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Pioneer Natural Resources Co (PXD) CEO Scott Sheffield on Q2 2019 Results - Earnings Call Transcript

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Q2: 08-06-19 Earnings Summary

Press Release SEC *10-Q* *Slides*

EPS of $2.01 beats by $0.15 | Revenue of $1.92B (-8.91% Y/Y) misses by $-398.3M

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Pioneer Natural Resources Co (NYSE:PXD) Q2 2019 Earnings Conference Call August 7, 2019 10:00 AM ET

Company Participants

Neal Shah - VP, IR

Scott Sheffield - President, CEO & Director

Jerome Hall - EVP, Operations

Richard Dealy - EVP & CFO

Conference Call Participants

Arun Jayaram - JPMorgan Chase & Co.

Douglas Leggate - Bank of America Merrill Lynch

Jeanine Wai - Barclays Bank

John Freeman - Raymond James & Associates

Brian Singer - Goldman Sachs Group

David Deckelbaum - Cowen and Company

Charles Meade - Johnson Rice & Company

Robert Brackett - Sanford C. Bernstein & Co.

Operator

Welcome to Pioneer Natural Resources second quarter conference call. Joining us today will be Scott Sheffield, President and Chief Executive Officer; Rich Dealy, Executive Vice President and Chief Financial Officer; Joey Hall, Executive Vice President of Permian Operations; and Neal Shah, Vice President, Investor Relations.

Pioneer has prepared PowerPoint slides to supplement their comments today. These slides can be accessed over the Internet at www.pxd.com. Again, the Internet site to access the slides related to today's call is www.pxd.com. At the website, select Investors, then select Earnings & Webcasts. This call is being recorded. A replay of the call will be archived on the Internet site through September 1, 2019.

The company's comments today will include forward-looking statements made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties are described in Pioneer's news release, on Page 2 of the slide presentation and in Pioneer's public filings made with the Securities and Exchange Commission.

At this time for opening remarks, I would like to turn the call over to Pioneer's Vice President, Investor Relations, Neal Shah. Please go ahead, sir.

Neal Shah

Thank you, Anna. Good morning, everyone, and thank you for joining us. Let me briefly review the agenda for today's call. Scott will be up first. He will discuss our strong second quarter results underpinned by solid execution and our reduced capital guidance for the full year. After Scott concludes his remarks, Joey will review our strong horizontal well performance optimized for rate of return. Rich will then update you on the benefits of our downstream planning for both oil and gas. Scott will then return with a brief recap and commentary. After that, we will open up the call for your questions.

So with that, I'll turn it over to Scott.

Scott Sheffield

Thank you, Neal. Good morning. On Slide 3, on creating value. The first key point is we continued to buy back stock. And obviously, where the stock is today, we'll be continuing to aggressively buy back stock third quarter on averaging our price down. What's great is that we had the best balance sheet of the independents in the business to allow us to do this.

We lowered the top end of guidance of our capital by $150 million with capital efficiency. We increased our dividend up to $1.76 per share with a yield of about 1.5%, and we moved to a quarterly distribution. We achieved our G&A savings much quicker than expected. Third quarter, we'll be down to about $2.25 of BOE. On a cash basis, we'll be below $2, moving toward a target established for the company toward $2 in 2020 and below $1.70 on a cash basis -- on a BOE basis.

We did achieve free cash flow when you add back in our restructuring charge for the second quarter based on the strip of about a week ago. We're establishing significant free cash flow second half of 2019 based on D, C & F on Footnote 2, continuing to show great cash flow uplift for our vision about exporting crude oil several years ago to the Gulf Coast and exporting around the world. $81 million, second quarter; $230 million, the first half.

Going to Slide 4. Again, we're at the top end of guidance on production and with significant improved capital efficiency. Next slide, Slide 5. Again, I mentioned that we're reducing our capital guidance at the top end by $150 million. Our drilling and completion teams are performing at very high levels around the clock. We've accelerated our West Texas annualization and reducing our infrastructure cost spending by about $50 million, lowering the top end of guidance approximately 4.5%.

Slide 6. Outlook is still great. Our $3.5 billion would have been increased over $3.6 billion without the restructuring charges. Again, I'll mention -- congratulate our D&C teams for executing at a very high level of efficiency throughout the company.

Slide 7, on improving our cost structure. I've already given the highlights, moving our targets down significantly. We're already in the top quartile of our peers. The goal is to stay there. As I said, the goal -- long-term goal is get below $2 per BOE, on a cash basis to be below $1.70 and continuing to drive it down over time.

Slide 8. Our priority is aligned now with our shareholders, returning $825 million already to shareholders, including when you pro forma the dividend yield of 1.5% and buying back over 2% of our stock already with future buybacks to occur in the third and fourth quarter, increasing the dividend already, as I mentioned, to 1.5% yield and going to a quarterly distribution. It's up 2,100% already from first quarter in '17. When you look at buying back our shares pro forma dividend and growing mid-teens, we're giving 20% back to the shareholders.

On Slide 9, 10, 11 and 12, I'm going to go ahead and give some comments on the big-picture items and hit a few highlights on those four slides, on 9, 10, 11, 12. After returning and studying recent reports put out by Rystad, WoodMac, IHS, S&P Global and some sell-side reports, I'm convinced Pioneer has the most productive wells and the highest returns in the Permian Basin with the most contiguous acreage position that's been drilling the widest-spacing wells more than anybody else over the last six years. We do not have to downspace due to our contiguous nature of our position in the Midland Basin.

From these reports, the Delaware is being drilled aggressively by many more operators. Rig count and Tier 1 acreage is being exhausted at a very quick rate. Similar reports have Delaware peaking in 2024 because of the aggressive drilling and downspacing because companies are essentially running out of inventory. The same reports are showing that the Midland Basin will not peak until the mid-2030s.

I am lowering my expectations of the Permian, reaching 1 million barrels of oil per day growth annually as it did in 2018. I'm still convinced the Permian will reach 8 million barrels a day at a much slower pace with the Midland Basin as the only growing basin in the U.S. past 2025.

Going back to Slide 9, 10, 11, 12 just to make a few key points, and we'll turn it over to our next speaker. On Slide 9 obviously are just points to make. As I mentioned already, I think they're mostly obvious on why the Midland Basin is the best place to be with our acreage position in regard to well cost, oil quality, OpEx and commodity mix.

Going to Slide 10. This is a slide from the sell side showing that we have the best returns in the business, and I'm convinced by reading these other reports that we do have that. Also, to help with those returns, Rich will talk more about the fact that we've aggressively hedged with the ramp in price several weeks ago, up -- with Brent up into the mid-60s. We're aggressively hedged in 2019 with swaps and also -- for the second half and also in 2020, which will help our return on capital employed growth. Over the next several years, the goal is to get our ROCE up to the mid-teens over the next 3 to 5 years in a $60 Brent market or $53, $54 WTI market.

Slide 11, the key there is the fact that we already have taken positions of exporting most all of our crude. We're getting the highest prices. And the fact that WTI in Midland, 41 degree gravity is getting a premium price to Delaware crude.

And Slide 12, again, we have an unmatched footprint, probably the highest net revenue interest among all the independents, low royalty. And it's interesting, the fact that we saw a couple of things happen. One with us, we sold some noncore assets this quarter for $20,000 per acre. It's the first time we've seen a cash deal coming in from private equity over the last two years. We'll continue to do that as we see great opportunity to deliver on noncore asset sales. In addition, we saw noncore assets go for $31,500 per acre with a deal that Oxy announced recently.

I'll now turn it over to Joey for Slide 13.

Jerome Hall

Thanks, Scott. Good morning, everybody. I'm going to be picking up on Slide 13. And I know there's been a lot of discussion recently about well spacing and the resulting parent-child effects. And as Scott just noted, Pioneer is in the enviable position of having approximately 680,000 mostly contiguous acres. And it's our acreage position that allows us to prioritize returns and capital efficiency rather than artificially increasing our inventory through tight well spacing, which, as we know, increases your exposure to the parent-child impacts. It's this development strategy, combined with advances in our completions methodology over time, is what has allowed us to improve well productivity year-over-year, as you can see there on the right-hand side.

Now I'm going to be moving on to Slide 14. Here, we're illustrating an additional factor in our ability to sustainably deliver strong margins. Looking on the left-hand side, you can see that based on gross production and normalizing on a two stream basis, Pioneer has consistently delivered the highest oil percentage in the basin since 2016. And then on the right-hand side, you can see that Pioneer also has the best 12-month cumulative oil production in the basin. These two facts, combined with our development strategy discussed in the previous slide, should lead to the best margins and the highest returns in the basin over time.

Now moving on to Slide 15, my last slide. Here, we're highlighting another successful Wolfcamp D appraisal. This was the Wolfcamp D 2-well pad in Western Glasscock County. And after 180 days, it is outperforming previous wells in the same area by 82%. We did POP 83 wells in Q2, and it's important to note that we deferred some facilities projects until the back half of the year. Once again, as Scott noted, a solid quarter of execution for the Permian team. Congrats to all.

And now I'm going to turn it over to Rich.

Richard Dealy

Thanks, Joey, and good morning. I'm going to start on Slide 16 where you can see that we had realized oil prices of $60 a barrel for the quarter that did include a significant uplift related to the firm transportation Scott talked about, moving our oil to the Gulf Coast where we get Brent-related pricing. This increased our price by over $4 for oil for the quarter and, as Scott mentioned, provided about $81 million of incremental cash flow or

$230 million year-to-date through June. Based on our forecasted prices for the third quarter, we are expecting an uplift of about $25 million to $75 million in the third quarter from the ability to move our oil and export it on the Gulf Coast.

During the second quarter, we moved about 90% of our oil, roughly 200 -- over 200,000 barrels a day to the Gulf Coast, of which 80% of it was exported with roughly 60% of that going to Asia and 40% to Europe. Longer term, our firm transportation commitments increase to about 250,000 barrels late into 2020, which is consistent with our forecasted production growth.

As I discussed in prior quarters, we try to move all of our products to higher-priced markets. And during the second quarter, we moved about 60% of our gas out west and priced it up the SoCal index. During the second quarter, this provided about $20 million to $25 million of incremental cash flow and improved our gas price realizations relative to other Permian players.

Once Gulf Coast Express comes on in the fourth quarter, we will move about 300 million cubic feet a day to the Gulf Coast and price that on a Ship Channel price index. And at that point, virtually all of our gas will be sold outside of the Permian Basin.

As Scott mentioned, before the pullback in commodity prices, we did aggressively hedge for 2019, 2020. So now we have for the remainder of 2019 72,000 barrels a day of oil hedged at Brent prices around $67 and 67,000 barrels a day of 2020 production hedged at roughly $64 per barrel, each of those with upside.

Turning to Slide 17. I think this slide highlights two key financial benefits that Pioneer has. First, it highlights the fact that we have the strongest balance sheet amongst our peers. And you can see that by -- measured against debt versus EBITDA basis. And then secondly, it highlights the quality of our wells and our cost structure as we have the highest EBITDA per BOE of our peers. This does not reflect the recent restructuring that we went through and the annualized $100 million savings. And so that will just further improve our margins. Both these point to our industry-leading financial position and our efforts to continue to improve margins and corporate returns.

So why don't I stop there, and I'll turn it back to Scott for a few closing comments.

Scott Sheffield

Thank you, Rich. On Slide 18, I think all these key points speak for themselves. But my primary goal is to get the company to free cash flow as quickly as possible as I came back. And I'm surprised how efficient, and all 2,000 employees are working around the clock and got us there already second quarter when I made the comment about getting free cash flow when you add back the restructuring charges for second quarter. So that's what I'm most proud of. We're going to continue to deliver free cash flow, and it's going to be a balance between growth, returning -- increasing dividends. As I mentioned earlier in the past, the goal is to get up to the average of the S&P 500 as quickly as possible and then also continuing our share buyback program. So again, I think all these key points speak for themselves, so I won't go over detail. Again, thanks. We'll turn it up over now to the Q&A session.

Question-and-Answer Session

Operator

[Operator Instructions]. And we'll now take our first question from Arun Jayaram of JPMorgan.

Arun Jayaram

This first question perhaps for Joey. I was wondering, Joey, if you could maybe discuss the optimal project or well packet size that you think is there to optimize returns and free cash flow generations from your asset base.

Jerome Hall

So from an execution perspective, the three well pad is what has been our bread and butter through and through. But as time is going on now, we're increasing that to four and six wells, and we're getting extremely good at that. But it's kind of hard to explain it as a package because sometimes we drill these larger projects with one rig and sometimes, we drill with same two rigs. But I would say going forward, it's not going to be uncommon for us to see 4, 6, 8 and 10 well pads. And probably, the sweet spot, somewhere in the six well pad size.

Arun Jayaram

Great. And just to my follow-up, Scott, in the press release, you guys highlighted how you believe that executing on the mid-teens oil growth outlook is the best or optimal in terms of generating top-tier returns and optimizing your free cash flow generation. My question is thinking about the next couple of years, you started the year running 24 rigs. You're down to 19. I think your guidance called for a rig count between 21 and 23 this year, and we thought you needed to add two or three rigs kind of per annum to support that growth. So just wondering how you're thinking about the next couple of years, particularly with Brent prices now moving towards in the mid-50s.

Scott Sheffield

Yes. First of all, I just don't think the world's going to -- it could, but I don't think the world's going to be $55 for the next three years. That puts WTI down to about $48, $49 net prices to people or $45. You're going to see a significant fallback in Permian growth. You'll probably move toward no growth for most people. But on that basis, we've got a great balance sheet. We have cash in the balance sheet, and we can drill through the cycle if we choose. So we're sticking with our mid-teens growth long term, adding two to three rigs per year. So I have -- we haven't changed our opinion at this point in time even if we go to the mid-50s.

Operator

We'll now take our next question from Doug Leggate with Bank of America.

Douglas Leggate

Scott, yourself and your offspring are the two only stocks green in the screen this morning, so congrats on the progress you've made since you got back.

I've got two questions, if I may. First, on the commentary in the press release about acreage sales on longer-dated stuff that you might not get to in this slower rate of growth, I guess, versus what we had previously thought of Pioneer. How is that process evolving?

Do you expect meaningful asset sales period? And if you can maybe just give us a broader update on how things are going with Targa and maybe your considerations around water infrastructure.

Scott Sheffield

Yes. In regard to all three, both infrastructure items you mentioned, natural gas, midstream and water and also on drillco, we will update when we complete those three items. So I expect two of them will be done by the end of the year. And then water, as we mentioned in the past, we're evaluating it now and we'll make it -- the Board will make a decision in 2020. So all three are being evaluated, proceeding as expected.

In regard to acreage sales, we will continue -- as I mentioned in the past -- over the last two years, there hasn't been much done, except for the Oxy transaction, which people have established acreage costs somewhere between $40,000 and $55,000 per acre for that transaction by various sell-side and external reports. We've seen this recent transaction for Ecopetrol doing a deal with Oxy at $31,500 per acre. In our treasure maps in the Midland Basin is where the experts, only 15% of that acreage was in core, 85% was noncore. So it seems like a very, very high price for noncore acreage. We would sell noncore acreage all day long at $31,500 per acre. Hopefully, we'll get continued asset noncore acreage for $20,000 per acre. So we are excited about that transaction.

And so far, the drillco process, as I mentioned earlier, if we decide to pursue with that by the end of the year, it's established around the same prices I've already mentioned, somewhere in that $20,000 to $30,000 per acre is what we would be selling that piece of the acreage for when you look at their expected returns. So hope that helps, Doug.

Douglas Leggate

Yes, it does. My follow-up is maybe for Rich. And it is kind of a philosophical question, I guess, because tripling or stepping up the dividend the way that you've done really starts to address an issue, I guess, that oil industry has been challenged with, which is how to value your sector that you in particular and obviously the general E&P space almost to the point of thinking along the lines of a dividend discount model with the depths of the acreage that you have in inventory and so on. So my question really is in order to help the generals do something like that, you need to have an idea what your thoughts are on future dividends strategy, payout ratios, trajectory for how that growth might follow your underlying capacity for cash flow growth. So I'm just wondering if you could share with us, now that you've reset the dividend to remain competitive as to how the growth rate with -- how do you think about that?

Richard Dealy

As we've demonstrated and Scott talked about, increasing from $0.08 on an annualized basis over the last couple of years to $1.76, it's clearly a focus of the company. And as we move to a free cash flow generative model, as we think about it longer term, I think we want to get to a dividend level that's competitive with the S&P 500. We'd like to do that as soon as possible, but we've got to be prudent about it where commodity prices are at. And as I said before, I mean returning capital to shareholders is an important part of our value proposition and is something that we'll continue to do over time.

Douglas Leggate

But is there like a payout target that you would consider like keeping it less than 10% of cash flow or something of that ilk?

Richard Dealy

I think, Doug, over time, we want to evaluate that. Clearly, we want to be free cash flow positive, and a chunk of that will be designated to go back into returning money to shareholders.

Douglas Leggate

Okay. We'll see how it evolves. Sorry, Scott, go ahead.

Richard Dealy

The exact percentage today, I just can't tell you what the exact percentage will be, but it will be -- a fair amount of that free cash flow will be returned to shareholders.

Operator

I'll now take a question from Jeanine Wai with Barclays.

Jeanine Wai

So in terms of the rig additions potentially in the back half of the year and trying to best position Pioneer operationally for 2020, can you talk about what the primary considerations are for deciding on whether you do add those rig fleet in the year and maybe how much lead time you need for planning purposes and how quickly you can actually pick up rigs?

Neal Shah

Jeanine, it's Neal. In terms of where rig count average, we put out in the beginning of the year in terms of rig budgeted, we have that average of 21 to 23 for the full year. We started the year for 24 -- at 24 rigs. We averaged roughly around that 21, 22 during Q2. We're exiting at 18 to 19. So we're expecting we'll remain well within our guidance. Q3 will roughly be, from a rig count perspective, flat with Q2. Q4 activity will be based on our thoughts on final 2020 plans, which we're still evaluating currently. But historically, as you've seen from last year, we -- it's all encompassed, as we know, as we discussed within the budget. So there would be no increase whatsoever to CapEx as we think about Q4 rig adds or activity adds in advance of 2020. But again, we're still in the process of formulating our 2020 plans.

Jerome Hall

And Jeanine, I'll just add that as far as advance notice, we have rigs that are available to us. And we just need 30 to 60 days advance notice to get those rigs back on again and mobilized.

Jeanine Wai

Okay. Great. And then, I guess, switching gears. Your marketing strategy is a big differentiator for Pioneer and you transported 205,000 barrels a day to the Gulf Coast during Q2. And I believe that amount of firm transport ramps as you ramp your own production over 250,000 barrels a day over the next couple of years. And there's been some debate in the industry on the status of just kind of new dock, new tank build-out in

Corpus Christi, the status of port dredging and all those other stuff. Do you think you can generally comment on your thoughts on this industry-wide? And then if you can provide any details on Pioneer's incremental dock and tank capacity that supports going from the 205,000 to 250,000 and whether there are any changes in your existing associate infrastructure over the next couple of years, too. So just trying to evaluate the risk/reward of your marketing agreements.

Richard Dealy

Sure, Jeanine. I think when you look at it and look at what's happening on the Gulf Coast, particularly in Corpus, there is a tremendous amount of export capacity being added. And so we don't see that as really a restrictive thing. And we're glad to see those are being added, we're glad to see the SBM projects that are -- hopefully get approved to take oil offshore and load bigger ships offshore. So I don't really see a bottleneck from that perspective really to what the growth of the U.S. crude market will be because most of that has got to get exported.

What I would say in terms of Pioneer's contracts, when we built our profile going from when we started at 15,000 barrels a day up to the 250,000 by the end of 2020, we built in all the -- in those agreements that we would have storage capacity and dock space for all those barrels. And so even past 2020, as that 250,000 continues to grow, we have dock space and contracts to storage as well. So we've matched all those things together to make sure that we don't get stuck without being able to get on the water.

Jeanine Wai

I guess after the -- part of that is there's some debate on whether there's delays in new capacity with dock space and tanks and things. So can you just verify that everything you have is existing? Or are you relying on new projects?

Richard Dealy

No, ours is all existing. So we're not relying on any new projects to meet our trajectory of production growth and moving those barrels offshore.

Operator

We'll now take our next question from John Freeman with Raymond James.

John Freeman

Last quarter, you highlighted that one of the initiatives was on reducing field facilities capital spending partly due to higher utilization of existing facilities. So when I look at Slide 5 and about half of the reduction in the CapEx guidance was driven by the reduced gas processing and water infrastructure spending coming down by about $50 million, I'm trying to get a sense of how much of that is -- I guess, should be like a permanent reduction as opposed to some of that spending just being pushed to some outer-years.

Richard Dealy

Yes. I would say as it relates to timing on that -- well, I'm just thinking -- I know on gas processing, it's really just timing and it's when the 2020 plant was going to get built, so it's just really timing there. It will eventually get done. It's just because of the little slower growth that they don't need to build those plants quite as fast. On the water side, really, that's really our subsystems. And so as we reduced our growth profile a little bit and changed from where we were previously in how we maximize utilization of existing facilities, we were able to just push some of that capital out. And so it's going to get deferred, so those subsystems will get built in later years. But we don't need to build them in 2019.

Neal Shah

So John, I was going to say that being said, tagging on Rich's commentary, we have talked about our water spending coming down next year as well, so it's not that you're going to see an increase in water spend for 2020 over 2019. While it is deferred, that water spend will still come down in 2020.

Richard Dealy

The Midland water treatment, the facilities are -- capital for 2020 is significantly less than what it is in 2019.

John Freeman

And I guess, sort of along those same lines is my follow-up. The facility in Midland, the wastewater treatment facility upgrade, it looks like that's a little ahead of schedule from what you all had planned last quarter where you said sort of early 2021 and now it's late 2020. Can you just remind us what the cost of that upgrade was?

Richard Dealy

The total cost of that facility is roughly around $125 million. And I would say, John, there's really no changes on timing. It's on schedule and on budget.

Operator

I'll now take a question from Brian Singer with Goldman Sachs.

Brian Singer

You mentioned, Scott, in your comments that you have the flexibility to spend through the cycle, and the balance sheet is certainly at a very low leverage with minimal debt. Can you talk to how willing you are to use the balance sheet and where your leverage thresholds are, either to drill through a down cycle or to buy back stock above and beyond internally generated free cash flow?

Scott Sheffield

Yes. I mean obviously, we got to have various views on commodity prices, but I just think the long-term goal is to have the flexibility. And you can't have the flexibility without having a great balance sheet. So like I was asked earlier about $55 Brent, obviously, at $55 Brent the next three years, I think Arun asked the question, we probably wouldn't change our plans. But we have the flexibility. If it drops too low, then we could reduce -- we have the flexibility to reduce the rig count. We could stay with the rig count, but we've got to combine that with achieving free cash flow.

So our cost under those scenarios would come down significantly from the service companies. As oil prices drop, so that's going to have a big -- so it's hard to answer the question if you do have a severe drop in commodities for several years. Generally, what's happened is that I just don't think the OPEC countries and the rest of the world -- lower oil prices will generate generally higher demand, then things will pick up fairly quickly as we've seen through the various cycles. So it's tough to really answer that long term, Brian, but the most important thing is that we have the flexibility to do any of the above that you mentioned.

Brian Singer

I guess, what I was kind of hoping for maybe was is there any upward leverage ceiling by which you would say, you know what, it's not necessarily worth drilling through? Or is there upward leverage ceiling that you would be tolerant to buy back stock regardless of the commodity environment above and beyond what you're getting post-dividend from free cash flow?

Richard Dealy

Yes. I'll say, Brian, we wouldn't want our -- from a leverage metric outlook and a debt-to-EBITDA basis, we wouldn't want it to be above 1x. We're just thinking in this business that we need to be below that level. So I think that would be what I would say the upper limit would be.

Brian Singer

Great. And then my follow-up is with regards to the Wolfcamp D results on Slide 15. Can you just add a little bit of color on what's different about the completions or the well performance of the locations chosen that drove the performance you're seeing here?

Jerome Hall

Yes. So all three is in the Wolfcamp D that we reported on here recently are relatively far away from each other. I think in one instance, about 10 miles; in another instance, about 18 miles and actually 50 miles away from our previous pad in the south area. So what we're doing is we're testing different areas. The completion recipes are relatively the same. We've done some testing of different cluster spacing and different amount of clusters because the pressure is higher, and our ability to create those fractures, it takes more energy. But for the most part, the completions have been relatively the same.

But again, we're not really testing different methodologies. We're testing different areas. We've got four other future Wolfcamp D tests planned, and they're also -- and two of them are in similar areas to the previous three and the other ones are in new areas. So again, we're mainly testing areas and appraising areas, not necessarily the completion technique, but we are making tweaks as we go.

Operator

We'll now take our next question from David Deckelbaum with Cowen.

David Deckelbaum

Just wanted to ask as you think about -- you talked about the rig plans going into next year, your sensitivities around cash flows, I guess just -- or commodity prices rather. As you think about the 21 to 23 rigs, should we still be thinking about that sort of flat split of 5 rigs in the south? Or I guess what are you seeing there recently that -- is that going to compel you to increase allocation? Or should that be kind of steady state there?

Jerome Hall

No. I think you could expect to see kind of a similar level of activity in the south as you currently see.

David Deckelbaum

Okay. And I guess just -- I know part of the capital budget tweak down was realizing some of the -- or adopting some of the in-basin sands a bit earlier than you had budgeted. I guess all else equal now, how do you think about your well cost trends going into the end of the year from where we are today? And do you still see some fat to take out going into '20, I guess, on a percentage basis?

Jerome Hall

I would say the big chunks, we realized them the first half of the year, that namely being the ProPetro transaction and also the West Texas sand. The -- and some of those relate to other changes that we've made related to the type of chemicals and moving from gels to less gel and even to slick water. So those changes for the most part have transpired.

So I would say moving forward most of what we'll see are efficiency gains. That's what we've seen both on the completions and on the drilling side. So I would say the big gainers have mostly happened in the first half, and we'll just see efficiency gains in the second half of the year.

David Deckelbaum

And if I could just ask one more. Scott, high level, you talked about how, in your view, we don't see any other basin in North America, I guess, of size growing beyond 2025 other than Midland. Just given that view, does that -- how does that square with your thought process around pursuing some drillcos or selling acreage? And wouldn't that inherently kind of increase the scarcity value for your company over time? You already have a free cash projection out there that's achievable in the mid-50s. You're already growing in dividend. I guess how are you balancing that as you think about just managing this business over the long term?

Scott Sheffield

Yes. As I've said before, David, the drillco acreage is focusing on acreage that is expiring over the next five years. And that's where the main focus of it is. And so it's lower returns. It's still worth drilling today, and we drilled a few wells on it. And outside -- I mean offsite activities have shown that there are some other operators that are drilling in the area, but it doesn't meet our current hurdle rates above 50%. And so that's the acreage that we're focused on, on drillco, so that's the main difference.

But I think you're right. Based on the scarcity, if Midland Basin is the only basin growing past 2025, it will make Pioneer's properties worth twice as much money or 3x as much money at some point in time over the next 5 to 6 years.

Operator

I'll now take our next question from Charles Meade with Johnson Rice.

Charles Meade

I wanted to ask a question. You guys have already spoken quite a bit on your marketing arrangements. So I wanted to ask a question perhaps for Rich. If you guys see -- there's already -- there's been some emerging differentiation between grades coming out of the Permian. Do you guys see more differentiation, I'm talking -- both in how you market and the pricing that you receive going forward?

And looking way further down the road, you guys have this 41-degree crude. My understanding there is that's where we're going to be relatively short in the U.S. compared to these lighter, more condensate grades. And so long term, do you guys anticipate that actually that crude is maybe going to make it to the Gulf Coast but stay there?

Richard Dealy

No. Whether it gets -- I mean it's all going to get to the Gulf Coast, for sure, and -- but I still think a big chunk of it is going to get exported. But clearly, the Midland grade, 41 degree gravity grade is getting premium pricing. For the last four months or so, it's averaged about $1.50 relative to the lighter crude coming out of the Delaware. And with the Delaware growth exceeding out of the Midland that Scott talked about, there's going to be more of the lighter quality step-on, which should make the value of our 41 degree barrel that much higher. So I think you're going to continue to see that price move up.

On the gas side, I think it's important to have takeaway out of the basin because I think any gas in the basin and there's not demand there, so it's got to get elsewhere and most of it's got to get to the Gulf Coast around California markets and mainly into LNG markets. And so we're aggressively moving our gas via whether it's Gulf Coast Express or Whistler down to the Gulf Coast as we continue to grow and getting it locked into LNG facilities or exported to Mexico. So I think both of those are important things.

Charles Meade

Got it. And Scott, I've always enjoyed your macro comments and your willingness to offer your opinion on that. I have two quick questions for you. You mentioned Delaware peaking in 2024 and Midland maybe in the mid-30s. I was wondering what the Brent price assumption was for that. And then the second piece, as I'm watching the Permian volumes through 2019, I'm starting to -- the way it looks to me is that there's going to have to be more growth in the back half of the year than we've seen so far to reach some of these estimates for Permian growth is in 2019 as a whole. And I'm wondering if you can offer your thoughts on Permian growth in the back half of '19.

Scott Sheffield

Yes. Most think tank groups are lowering their Permian growth from last year to about 600,000 to 700,000 for this year. And they're also lowering it for 2020 and going forward for all the reasons that I've said. So -- and that's due to the fact that people are drilling aggressively. They're downspacing. Now people are going to have less cash flow if we stay in the lower oil price environment. People don't want to build debt in this environment, so there's a lot of reasons why I just don't think we're going to see the long-term growth. So the majors are the only ones that are drilling aggressively. I don't see them slowing down. They've made some comments on their calls that they're having some issues. But -- so right now, I just don't -- growth is coming down for the reasons I have mentioned, so I'll stop there.

Operator

I'll now take our next question from Bob Brackett with Bernstein Research.

Robert Brackett

A question on the maturities of debt coming due in sort of '20 and '21. They're relatively modest relative to your enterprise value. But how do you prioritize either paying those out or refinancing them versus using the available funds for share buybacks?

Richard Dealy

Yes. I think right now, the current plan is we really look at it on a debt-to-EBITDA basis and where our leverage sits. But currently, right now, into the 2020, we're targeting to pay that off with cash on the balance sheet and still evaluate what to do in 2021.

Robert Brackett

And then a somewhat separate question. Scott, you mentioned earlier that you'd be happy to sell noncore acreage all day long in, say, $30,000. Can you just sort of contrast what you mean by noncore? Is it really high-quality acreage that you wouldn't get to in a timely fashion? Or is it the geologically sort of less core?

Scott Sheffield

Well, the piece that we sold for $20,000 per acre was an extreme North Martin County. If you remember, we did an asset sale about three years ago, and that was on the Dawson, Martin County line. It's in that similar area. It was isolated. So those are the type pieces that are noncore. It's a question whether or not you call the stuff we're looking in drillco area. I sort of call it lower-tier core. But that's the acreage that we're focused on, on the drillco. And so we've got an extensive acreage position. But -- so that's the difference between the two. So I can't tell you exactly how much noncore we have, but we do have some pieces that if we can't trade or block it up, we're going to sell somewhere between that $20,000 and $30,000 per acre range.

Robert Brackett

Is it fair to say it's more non-Pioneer core versus nonbasin core?

Scott Sheffield

Exactly. Exactly.

Operator

And that concludes today's question-and-answer session. I'd like to turn the conference back over to Mr. Sheffield at this time for any additional or closing remarks.

Scott Sheffield

Again, thank you for participating. Great questions, and we'll talk to everybody over the next three months. And see you next quarter. Thank you.

Operator

And once again, that does conclude today's conference. We thank you all for your participation. You may now disconnect.