UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): November 2, 2016

DEVON ENERGY CORPORATION
(Exact Name of Registrant as Specified in its Charter)

Delaware	**001-32318**	**73-1567067**
(State or Other Jurisdiction of Incorporation or Organization)	**(Commission File Number)**	**(IRS Employer Identification Number)**

333 West Sheridan Avenue, Oklahoma City, Oklahoma	**73102-5015**
(Address of Principal Executive Offices)	**(Zip Code)**

Registrant's telephone number, including area code: (405) 235-3611

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operations and Financial Condition.

On November 2, 2016, Devon Energy Corporation (the "Company") held its third quarter 2016 earnings conference call. As a result of technical issues experienced during the call, the webcast of the conference call accessible through the Company's website was not properly functioning. A copy of the transcript of the conference call is furnished herewith as Exhibit 99.1 and is incorporated herein by reference, and a replay of the webcast is also available on the Company's website at www.devonenergy.com .

Item 7.01 Regulation FD Disclosure.

The information in Item 2.02 above is incorporated herein by reference.

In accordance with General Instruction B.2. of Form 8-K, the information provided in this Current Report on Form 8-K, including Exhibit 99.1, shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), or otherwise subject to the liabilities of that section, nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Information Regarding Forward-Looking Statements

The transcript furnished as Exhibit 99.1 contains forward-looking statements within the meaning of the federal securities laws. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company. These risks include, but are not limited to, those identified in the Company's Annual Report on Form 10-K and its other filings with the Securities and Exchange Commission. Investors are cautioned that any such statements are not guarantees of future performance and that actual results or developments may differ materially from those projected in the forward-looking statements. The Company does not undertake any obligation to update such forward-looking statements as a result of new information, future events or otherwise.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits .

Exhibit No.	Description
99.1	Transcript of third quarter 2016 earnings conference call of Devon Energy Corporation.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

DEVON ENERGY CORPORATION

By: /s/ Carla D. Brockman

Carla D. Brockman
Vice President Corporate Governance and Secretary

Date: November 2, 2016

EXHIBIT INDEX

Exhibit No.	Description
99.1	Transcript of third quarter 2016 earnings conference call of Devon Energy Corporation.

Exhibit 99.1

Corrected Transcript

02-Nov-2016

Devon Energy Corp. (DVN)

Q3 2016 Earnings Call

FACTSET: callstreet

1-877-FACTSET www.callstreet.com

Total Pages: 23

CORPORATE PARTICIPANTS

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.

Sue Alberti
Senior Vice President-Marketing, Devon Energy Corp.

Thomas L. Mitchell
Chief Financial Officer & Executive Vice President, Devon Energy Corp.

OTHER PARTICIPANTS

Evan Calio
Analyst, Morgan Stanley & Co. LLC

Doug Leggate
Analyst, Bank of America Merrill Lynch

Ryan Todd
Analyst, Deutsche Bank Securities, Inc.

Arun Jayaram
Analyst, JPMorgan Securities LLC

Edward George Westlake
Analyst, Credit Suisse Securities (USA) LLC (Broker)

Scott Hanold
Analyst, RBC Capital Markets LLC

Peter Kissel
Analyst, Scotia Howard Weil

David Martin Heikkinen
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC

Matthew Merrel Portillo
Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.

David R. Tameron
Analyst, Wells Fargo Securities LLC

James Sullivan
Analyst, Alembic Global Advisors LLC

Bob Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

MANAGEMENT DISCUSSION SECTION

Operator : Welcome to the Devon Energy third quarter 2016 earnings conference call. At this time, all participants are in a listen-only mode. This call is being recorded.

I would now like to turn the call over to Mr. Scott Coody, Vice President, Investor Relations. Sir, you may begin.

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.

Thank you and good morning, everyone.

I hope everyone has had the chance to review our third quarter financial and operational disclosures that were released last night. This data package includes our earnings release, which includes forward-looking guidance, and our detailed operations report.

Also on the call today are: Dave Hager, President and CEO: Tony Vaughn, Chief Operating Officer; Tom Mitchell, Chief Financial Officer; and a few other members of our senior management team.

Also, I would like to remind you that comments and answers to questions on this call today will contain plans, forecasts, expectations, and estimates that are forward-looking statements under U.S. securities law. These comments and answers are subject to a number of assumptions, risks, and uncertainties, many of which are beyond our control. These statements are not guarantees of future performance, and actual results may differ materially. For a review of risk factors related to these statements, please see our Form 10-K and subsequent 10-Q filings.

And with that, I will turn the call over to Dave.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.

Thank you, Scott, and welcome, everyone.

Devon delivered another outstanding performance in the third quarter both operationally and financially. Our development programs delivered the best quarterly drillbit results in Devon's 45-year history, with new wells reaching peak 30-day rates of nearly 2,000 BOE per day. These prolific drilling results were centered in our world-class STACK play, where oil production increased by nearly 40% year over year.

Furthermore, the value of Devon's production continued to be enhanced by substantial cost savings achieved during the quarter. We are now on pace to reduce operating and G&A costs by $1 billion for the full year, which provides an uplift to our margins of nearly $5 per BOE produced.

In addition to our strong operating performance, another important accomplishment for Devon was the recent completion of our $3.2 billion asset divestiture program. These accretive transactions significantly strengthen our investment-grade position. And as a result, our net debt has now declined by 45% since the beginning of the year. To further enhance our financial position going forward, we've also been much more active building out our hedging position with the recent increase in commodity prices.

With a more focused asset base and improved balance sheet, the next step in our strategic plan is to accelerate investment in our world-class onshore resource plays. By the end of next month, we plan to have 10 operated rigs running, focused within our top two franchise assets, the STACK and Delaware Basin.

Looking ahead to 2017, we are still working toward finalizing the details of our operating and capital plans. However, I can tell you that at $55 WTI pricing, our upstream cash flow in 2017, including EnLink distributions, is projected to expand by more than the 100% year over year to around $2.5 billion. Under this scenario, we would steadily ramp up drilling activity over the next several quarters to as many as 15 to 20 operated rigs in the U.S. by year-end 2017. This program would represent upstream capital spending of around $2 billion, allowing us to invest within available cash flow.

On a retained asset basis, this focused investment in higher-margin projects is expected to drive double-digit oil growth in the U.S. in 2017 compared to the fourth quarter of 2016, which marks the low point in Devon's production profile. As a result of this growth in oil volumes, top line production of 2017 will range from low to mid - single-digit growth compared to Q4 2016. This range is dependent upon our level of ethane rejection during the year.

Importantly, this capital plan is designed to create operational momentum and much stronger growth rates heading into 2018. At a $60 WTI price point in 2018, our upstream cash flow has the potential to reach $3.5 billion, a greater than 200% increase from today's levels. Under this scenario in 2018, we will continue to aggressively ramp up our drilling programs within the U.S., with the majority of this capital directed toward the STACK and Delaware Basin. This low-risk drilling activity is expected to drive production growth of greater than 30% from our STACK and Delaware Basin assets in 2018. This strong growth would further transition Devon's product mix toward higher-margin light oil production in the U.S.

Now I want to be very clear. While we're excited about the outstanding growth prospects that reside within our portfolio, our capital allocation will be focused on value and rates of return, not to pursue top line production growth. And if commodity price volatility continues, our capital programs have significant flexibility, with no long-cycle project commitments and negligible leasehold expiration issues. This flexibility allows us to be nimble and tailor activity to invest directionally within cash flow.

Another strategic imperative for Devon in the upcoming year is to further delineate and better characterize the growing resource base associated with our U.S. resource plays. Between the STACK and Delaware Basin alone, we have exposure to more than 1 million net acres and thousands of development-ready drilling locations that are highly economic at today's prices.

To advance our understanding of the ultimate recovery and resource potential within these two world-class plays, we have important appraisal work underway. In the STACK, this catalyst-rich activity is concentrated on the Meramec infill spacing pilots and further derisking of the Woodford oil window. In the Delaware Basin, the Leonard Shale opportunity set continues to expand, and we are now flowing back on our first STACK lateral test that will help shape our view on how to best develop the three prospective landing zones in this oil-rich shale.

2017 will also be a breakout year for our Delaware Basin Wolfcamp program, as we began to actively develop this emerging play. The Wolfcamp will have a material impact to Devon's resource potential in the Delaware, and we are excited about progressing our understanding of the 9,000-plus potential locations we have identified in this play.

The bottom line is that Devon's asset portfolio has never been in better shape than it is today, and I believe that the quality and depth of our opportunity set is unmatched in the industry. We possess thousands of undrilled locations that are extremely well positioned on the North American cost curve. This high rate of return inventory will continue to expand as we derisk the tremendous resource upside associated with our STACK and Delaware Basin assets. With this resource expansion, it could necessitate additional high-grading of our portfolio, monetizing less competitive assets and accelerating the development of our highest rate of return inventory.

So in summary, before we move to Q&A, I want to leave you with a few key messages from today's call. First, our improved financial positioning now allows us to aggressively accelerate drilling activity across our best -in-class resource plays while continuing to focus on the value and rate of return of each investment. These accelerated drilling plans will drive attractive cash flow growth in 2017 and 2018 compared to today's level and continue to transition Devon's product mix toward higher-margin light oil production in the U.S.

In conjunction with our shift to higher-margin production, do not lose sight of our peer group leading leverage to rising commodity prices. For every $1 increase in realized price on a per BOE basis, Devon generates more than $200 million of incremental cash flow annually.

Looking beyond prices, Devon is also catalyst-rich over the next several quarters, as we further delineate the massive resource upside associated with the STACK and Delaware Basin positions. And finally, with the continued growth in the quality and depth of our resource base, we expect to have an overabundance of opportunities. If this is the case, we are very willing to further high-grade our portfolio and deploy additional investment toward the best projects in our portfolio.

With that, I'll turn the call back to Scott.

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.

Thanks, Dave. We will now open the call Q&A. Please limit yourself to one question and a follow-up question. If you have further questions, you can reprompt as time permits. With that, operator, we will take our first question.

QUESTION AND ANSWER SECTION

Operator : [Operator Instructions] Your first question comes from Evan Calio with Morgan Stanley. Your line is open.

Evan Calio
Analyst, Morgan Stanley & Co. LLC
Q

Good morning, guys.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Good morning, Evan.

Evan Calio
Analyst, Morgan Stanley & Co. LLC
Q

Dave, you mentioned you're evaluating the total inventory as you prepare two core basins to move into development mode in 2017, and that's something that's really supporting a newer 2018 guide here. But the higher-level question, though, is what do you believe the optimal inventory depth should be maybe on a years of activity basis? It sounds like we should expect a continued rationalization program if locations grow well beyond those optimal levels. Any thoughts there?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Evan, and that's always a very difficult question to answer exactly. What is the right inventory level? Somewhat akin to the old R-over-P [Reserves-over-Production] ratio we used to talk about for many years. I think you can obviously directionally have so much inventory that you're not maximizing the value of your inventory, or you could have too short of an inventory that there are questions about the long-term growth of the company, so there's certainly a balance point in there.

To name an exact amount of years of inventory is somewhat difficult. I'd say I tend to think probably somewhere on the order of 20 or so seems about appropriate, but it is certainly a subject that I often actually turn the question back over some of you guys to give your feeling. But I can tell you, I'm somewhere in that range, 20 – 25, something like that.

Evan Calio
Analyst, Morgan Stanley & Co. LLC
Q

Yeah 15 – 20 years from our view. A different question on, you provided year-end 2016 and 2017 rig target levels or unit levels. I know the board hasn't approved the budget yet. But can you talk about the ramp that's correlated to the move? Is it back-end loaded as you move into development mode, or is it – what's the ramp pace to the 15 units? And is the five delta something commodity related, or is that maybe asset supported, asset sales related? Any color there.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Let me walk you through that. So the 10 rigs at year-end 2016 is essentially set, and we are executing that. I think it's important to understand, it's really the 10 rigs plus the completion activity that we are conducting that's really driving our 2017 volumes. And so that's why we're very excited about the comp on the volumes that we've talked about in the operations report. The ramp up to the 15 to 20 rigs really won't add production in 2017, but that's why we're so excited about 2018 as we do ramp up to that level. That's what's going to provide the even higher growth levels as we move into 2018, led by more than 30% growth in the STACK and the Delaware.

Now the variability around that is really more – at this point I'd say more commodity price driven. Although frankly, we do have – we are committed roughly to live within cash flow. It there's a little bit of variability around that, we're willing to exceed cash flow by a minor amount, perhaps if necessary, supplement with incremental small-scale asset sales. We also, as you know, we've been hedging significantly more, so that's helped underpin and provide more comfort to the cash flows that we'll have in 2017. But the opportunities are there. We're confident that we have the opportunities there. So I'd say the delta is really more commodity price driven than opportunity driven.

Evan Calio
Analyst, Morgan Stanley & Co. LLC
Q

Great. Thanks, guys.

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.
A

Evan, this is Scott. Just one thing I'd like to add on that too. I would also say it's about productivity as well. If you look at where that capital is going, it's going to be focused in the STACK and Delaware Basin, and those are two of the highest rate of change plays that you're seeing as far as drilling days and improved completion designs. So I would say that we're getting better and better at that, so that would also have an impact with regards to what that rig ramp would be needed to deliver the production that we've talked about.

Evan Calio
Analyst, Morgan Stanley & Co. LLC
Q

Yeah, particularly in the [indiscernible] (14:30). Got it.

Operator : Your next question comes from Doug Leggate with Bank of America Merrill Lynch. Your line is open.

Doug Leggate
Analyst, Bank of America Merrill Lynch
Q

I was trying to say good morning, everybody.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Good morning, Doug.

Doug Leggate
Analyst, Bank of America Merrill Lynch
Q

So, Dave, you've raised the type curves obviously in the STACK, but you have not addressed the issue of the inventory. My recollection is you were using four wells per section, three upper and one lower, if I recollect. What do you need to see in terms of your density spacing in order to update that backlog, and what's your outlook thoughts on it, if you can?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp. A

Doug, just to be clear, the inventory is going up. There's no question about that. We've had about three successful pilots so far. I think we've tested now one zone up to seven wells per section. That's worked out very well. We have another 10 pilots or so. They're detailed in the operations report, the locations of those pilots. So really it's just a matter of timing when we feel like we have enough information from each of those pilots to increase the number. But there's no question it's going up. So, Tony, you want to add any details to that?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp. A

Doug, I think Dave summed it up perfectly. We're working on coming out of 2017 with development in two of our areas central to the work that we've been doing with the pilots. And we've got the detailed data already in-house on the three operated pilots. We're starting to get data in right now on three non-operated pilots. And as Dave mentioned, we've got another six or seven pilots that we're engaged in now. So all that information is helping us inform our 2017 development plans. And I think as we get more data under our belt, we'll come out and see a material increase to that inventory.

Doug Leggate
Analyst, Bank of America Merrill Lynch Q

Okay, I guess I'll have to be a little more patient. My follow-up, if I may, is I realize oil is heading in the wrong direction again this morning, and who knows what 2017 is going to look like? But you've laid out a trajectory that's got you tripling cash flow basically by 2018 at $60 oil. I'm just curious as to what should we infer by way of your activity level with that level of cash flow? And perhaps in even a higher oil price environment, where does Devon go in terms of activity, or do we flatten out at a targeted growth level at a particular rig level, but maybe return cash to shareholders at some point?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp. A

Doug, as you well know, we have a very deep inventory of opportunities, and certainly the two franchise assets that we have are the STACK play and the Delaware Basin play. And so if prices go even higher than that, we certainly can ramp up activity even further there.

We are always going to be mindful, though. I want to emphasize; we're going to be mindful of the returns. So we're not driven by top line production growth. We are driven by getting good returns for every dollar in our capital program, but we feel we have the opportunities we could further drive up activity in both of those areas, plus we have other areas that we are not funding right now as much as could be if we had higher cash flow levels. They already have returned well above the cost of capital, but they just don't compete as well as the Delaware Basin and the STACK.

In the Rockies, we are starting to fund now with one rig. We could add activity there with strong returns. And even the Barnett, and we've laid out some numbers in the operations report how we're driving down the cost there. We think we have a program that we can do both from the horizontal refracs and from additional drilling locations that right now are well above the cost of capital. They're just not as good as the Delaware Basin and STACK, so we are focusing our capital there because they're the highest returns. So we do not have a shortage of opportunities. And so I think if prices are even higher, we'd look at funding some of those opportunities as well.

Doug Leggate
Analyst, Bank of America Merrill Lynch
Q

David, I don't want to belabor or take up too much time here, but I want to be clear what I'm asking because one of your competitors is talking about a mid-cycle $55 level. I realize that's totally subjective, but their point is in a higher oil price environment, the industry got itself into bit of a mess by growing too quickly. And they would look upon that as a windfall and would not jerk around their rig count with a view to longer-term sustainable growth. What I'm hearing from you is that you would respond to a higher oil price with higher activity levels. I guess my question is, is that what the industry wants to see? Is high growth just going to keep this oil price in the problem we've got right now, or is there an argument that says work towards a growth level and return any perceived "windfalls" to shareholders? I guess that's really what I'm asking.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Doug, it's my view that what got the industry in trouble at the higher commodity prices is that there are a lot of projects that were funded out there that were very marginal projects, and we didn't pay enough attention to the reservoir. We didn't pay enough attention to the fundamental economics. And so I don't think it's so much the activity level in and of itself. It's the fact that this activity level was really going towards projects that didn't provide the returns that they should.

And so I can tell you here at Devon, we are very, very focused on returns, and we're very, very focused on the reservoir and making sure that each project that we do is going to provide good returns. So I don't necessarily think there's a problem on an individual company level as long as you can be confident you can provide good returns. I think what really happened is at $90 oil, a lot of these projects being funded were not providing good returns. We're overcapitalizing some of these fields, frankly, and that's what the big issue was.

Doug Leggate
Analyst, Bank of America Merrill Lynch
Q

I appreciate the answer, Dave. Thank you.

Operator : Your next question comes from Ryan Todd with Deutsche Bank. Your line is open.

Ryan Todd
Analyst, Deutsche Bank Securities, Inc.
Q

Great, thanks. Maybe if I could follow up on STACK activity, can you talk a little bit about how you view the mix of Meramec versus Woodford activity as we're looking at 2017, and any thoughts on what the potential swing in non- op CapEx might look like there?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

Excuse me, Ryan, Tony Vaughn here. Our plans are to, as Dave mentioned, we're going to be at – we're at six rigs coming into this year end, and we've got the capacity to build up that to roughly about 12 rigs. We have plans in the second half of 2017 to engage back into a drilling campaign on another row called the Jacobs Row, and you see that on page 10 of our operating report. So if I had to – we haven't gone through the budgeting process yet, so I can't say specifically how this will happen. But for the most part, our drilling activity up until about midyear of 2017 will be concentrated in the Meramec. And then in the second half of 2017, we'll take probably roughly about four of those rigs and move them into our Woodford campaign.

If you look at the magnitude of our OBO spending in the STACK play, it's quite substantial. I think we talked to you guys before about the level of participation that we had, not just in operated wells, but we have 430,000 acres in the play. So we have access to a lot of data, a lot of information, and that drives a spend of about $300 million per year from our non-operated exposure.

Ryan Todd Q
Analyst, Deutsche Bank Securities, Inc.

Okay, thanks. That's helpful. And then maybe I know this is always a hard thing to quantify, but any thoughts on what inning you're in for LOE and G&A cost reductions? The cost reductions over the past 18 months have been extremely impressive. Should we expect to continue to see downward pressure on those, and is there any risk to inflation in either one of those as we see rigs ramp over the next 12 months?

David A. Hager A
President, Chief Executive Officer & Director, Devon Energy Corp.

I'll take the G&A part and I'll let Tony talk about the LOE side. We obviously did a significant reduction in employees earlier in the year, on the order of 25%. It was a big move for us as a company, and it obviously involved some pain, losing some good friends. We did maintain the key operational capability and the key value drivers that can allow us to execute we feel comfortably a $3 billion capital program of about 20 operated rigs. And so we see really that we are at a given – what we've laid out here is potential for 2017 and 2018 that we are comfortable with the level of G&A in the company, and so I wouldn't expect a significant change on that one way or the other.

Tony may want to talk a little bit about the LOE side of the equation. I think probably we found most of the big gains, but I think that we're always continuing to look more. As the infrastructure increases in some of these fields, there may be some more things that we can do. So, Tony?

Tony D. Vaughn A
Chief Operating Officer, Devon Energy Corp.

Ryan, I think – I'll tell you I've got to hand it to our operating team both in the field and here in the office. They've taken a very passionate approach to driving cost out of the business, and you can see the improvements that we've made over the last two years. And I think if you were to look at the cost or the price of materials and services, it is starting to level out, starting to flatten out in most of those areas, but that doesn't mean we're still looking for opportunities to continually improve our business.

In some of those areas, we've unbundled or decoupled different components of our operations. As an example, separating the saltwater disposal from the water hauling vendors, that's offered improvements there. We've continued to build out our infrastructure and have more water and pipe now. We have a better power grid system, especially in the Delaware Basin. All that's tending to drive cost down. So probably the t ension that we see in the business is coming. We also have by virtue of our sale of the Access Pipeline an increased transportation fee that would be coupled into our LOE costs. But for the most part, our guys are continuing to work LOE in a very passionate approach.

Ryan Todd Q
Analyst, Deutsche Bank Securities, Inc.

Great, thank you.

Operator : Your next question comes from Arun Jayaram from JPMorgan. Your line is open.

Arun Jayaram
Analyst, JPMorgan Securities LLC
Q

Good morning, gentlemen. I wanted to see if I could discuss a little bit about your thoughts on guidance. You gave us a lot of clues how we should be thinking about 2017 and 2018 in terms of the ops report, but tell me if this is what you're trying to convey. You guided to at least double-digit U.S. oil production growth in 2017 versus the Q4 guidance. I think the guide was 105.5 MBOE per day at the midpoint. And then if we assume Canada is relatively flat from Q4 levels, including maybe a turnaround in Q2, that to me suggests that y our overall guidance, soft guide, however you want to call it, would be oil a bit north of 250 MBOE per day versus the Street at 243. Am I thinking about that right? And also, can you give us some sense of what capital it would take to achieve that in 2017?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Let me address first the capital and then I'll have Scott address the detailed question on the volumes. I did say in my opening remarks there that the capital in 2017 we anticipate being around $2 billion of E&P spend. But it is also important to understand that really the volumes in 2017 are being primarily driven by the completion work that we currently have ongoing in specifically the Eagle Ford but also other areas, and then in addition to that, the 10 rigs that we're going to have working by the end of this year.

The incremental capital of going from 15 to 20 rigs, which really rough numbers increases our capital budget that would be at 10 rigs if we stayed flat there for the year, probably about $1.6 billion versus going to 20 rigs would be around $2 billion. That incremental dollar is really driving 2018 volumes, which is why we're really excited just because of the timing of how long it takes to bring these wells on production. So it's not really a matter of $2 billion is needed to drive those 2017 volumes. We could do that at a lower level and it would just impact 2018, but that's again why we're even more excited about the growth potential in 2018. So, Scott?

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.
A

With regards to the production, Arun, I think directionally you're absolutely thinking about that correct. We would expect to be – when you combine the U.S. and Canada from an oil productive perspective we would expect to be north of 250,000 barrels. So we'll firm up that guidance as we get with our fourth quarter call. We're still working through the detailed operating and capital budgets, but directionally you're absolutely thinking about that correctly. And once again, I do want to emphasize, though, that is absolutely being driven by light oil growth in the U.S. So you're seeing a real time shift to high-margin production for Devon, which is going to significantly enhance our profitability.

Arun Jayaram
Analyst, JPMorgan Securities LLC
Q

That's great. Thank you, Scott. And just to follow up, Dave, you commented in your prepared remarks about potentially looking at opportunities just given the inventory depth to high-grade the overall portfolio. Can you give us a sense of timing and magnitude and just what you guys are thinking about in terms of potentially monetizing more assets?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.

A

There are a lot of variables that go into this equation. I can tell you, we want to get a greater sense of the inventory, particularly in the STACK and the Delaware Basin, where we are doing these spacing tests in the STACK play, both between the Meramec. You can also see there's now some Woodford oil potential that's developing underneath the STACK. I want to get a sense for that and how many zones in the Meramec are going to work. We've laid out that we're testing up to eight wells per section in the primary and six in the secondary in the Meramec. Now we're talking about a Woodford zone there.

And then in the Wolfcamp, we talked about the Leonard and testing how many zones in the Leonard may work, as well as the fact that the Wolfcamp is – we have 9,000 unrisked locations there, and we've moved about 500 or so into the risked locations, and that's going to continue to grow. So that's going to take till we'll start getting a better feel for that probably mid next year. So that's one factor in it.

And then the other big factor in it is really long-term commodity prices because you can see the leverage to the cash flow that we have from the operations report, the leverage that we have to higher cash flow at higher commodity prices, which is the highest leverage in the industry . And so where do we think long-term commodity prices are going to level out has a big impact on what cash flow we're going to have, which has a big impact of how many other opportunities that we can fund in other areas that already have potential returns well above the cost of capital, they're just not as big as the Delaware and the STACK. So we want to get a better handle from both of those variables, probably mid-2017 at the earliest before we make any strategic calls.

Arun Jayaram
Analyst, JPMorgan Securities LLC

Q

Great, thank you for that.

Operator : Your next question comes from Edward Westlake with Credit Suisse. Your line is open.

Edward George Westlake
Analyst, Credit Suisse Securities (USA) LLC (Broker)

Q

Good morning, congrats on the risked location update and the cash flow guidance. Just on the Delaware Wolfcamp, you've put in 500 risked locations. It looks like a large majority are in Rattlesnake and the Mi Vida. The 9,000 number, maybe just talk through the work that has to be done to unrisk those and what EURs you expect on the core 500.

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.

A

Okay. Ed, I think we've just talked about in the operations report the Rattlesnake and Mi Vida area, and we've mentioned that we have about 500 risked locations there. But we have a total of about 9,000 unrisked locations across our position in the Delaware Basin. And I'd have to say that the industry has done an outstanding job of derisking the play. It's moved from the Texas side of the basin up to the state line and now north of that state line, so we're utilizing a lot of that information. We do participate in some non-operated activity in there, so we're getting a good feel of the potential in the Wolfcamp.

I think some of the things that we're still anxious to understand through some of our pilot work that we'll engage in will be the vertical connectivity between that very thick Wolfcamp column. We know that out of the 2,000 wells drilled, and we've drilled some on the New Mexico side as well, we just haven't really prosecuted that in our development plan. But we know that from the X-Y through the upper – through the lower portion of the Wolfcamp, it's all productive. And so it will really be a matter of the development style that we choose to engage in.

I think one of the elements that we're incorporating into our thoughts as we go into 2017 is bringing in an aggressive approach from the Leonard A, B, and C intervals. We've got a stacked pilot engaged right now to help us understand the vertical connectivity. We've spent most of our time in the B zone. The industry has spent most of their activity in the C, so we know each of the three intervals are productive.

We're seeing some encouraging results. We're not commenting on that because the data is pretty young right now. We'll come back out and clear up the results of that soon. But we'll incorporate the three intervals in the Leonard with the typical work that we do in the Bone Spring and the two in the southern portion of the two New Mexico counties, and have a pretty aggressive approach into the Wolfcamp in both the Rattlesnake and Mi Vida areas. They'll be the first two areas that we engage the Wolfcamp.

Edward George Westlake Q
Analyst, Credit Suisse Securities (USA) LLC (Broker)

Thanks, that's a very fulsome answer. Just on the Eastern Woodford, your well cost is $6 million to $6.5 million and the EUR is 1,600 MBOE, and it's 25% oil, and that Old Ricky's Ridge well, it's 60% oil. It almost feels like it will be better than the stuff over in Blaine. As Blaine gets deeper, the costs go up. You're getting similar types of EURs. Maybe just a little bit of elaboration in terms of why those well results: A), they're cheaper; and B), the EURs are so strong, is it the thickness of the reservoir in that particular location?

Tony D. Vaughn A
Chief Operating Officer, Devon Energy Corp.

I think you're picking up on it. There's a lot of variability in the subsurface portions of the Meramec and the Woodford. The depth does run from the shallow being in the east to the northeast to the southwest, as you described. Also, about midway between the northeast of our position and the far southwest, there are some subsurface intricacies that make us run a third casing string. So as you move up into the Old Ricky's Ridge area, it's a very important data point there that we wanted to highlight simply because the oil cut is 60%. We really hadn't valued that in our thoughts about the Meramec. But as you can see up there, we think there could be a substantial NAV add if you move that high oil cut across the upper portion of our Meramec play. So this really sets us up for that stacked development from the five intervals in the Meramec and the Woodford.

Also unique about Ricky's Ridge, it was a 10,000-foot Woodford test. We incorporated 70 stages in that frac design and pumped about 2,600 pounds per foot of sand. So it was a pretty aggressive attempt to see what we could do there. We're very happy with the results. You can see some of the 90-day IP is solid, but the more important thing is the production profile is flat and much more optimistic than our initial expectations. So I think Ricky's Ridge is an important data point for us to keep her eye on.

David A. Hager A
President, Chief Executive Officer & Director, Devon Energy Corp.

And it's a little bit cheaper over there too because you're shallower to the northeast and get deeper to the southwest. And so that's true both whether you're drilling Meramec or Woodford wells.

Edward George Westlake Q
Analyst, Credit Suisse Securities (USA) LLC (Broker)

Thanks very much.

Operator : Your next question comes from the line of Scott Hanold with RBC Capital Markets. Your line is open.

Scott Hanold
Analyst, RBC Capital Markets LLC
Q

Thanks. I have a question on the STACK. It looks like you're going to be increasing activity in these longer 10,000-foot laterals. Can you give us a sense of how much of your acreage ultimately do you think is amenable to that? And what efforts are ongoing to help block up acreage more so this can become part of the long-term development plan?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

Scott, that's a good piece of the business that our business unit is engaged in every day. And so we're working with other operators there to block up and try to provide the most opportunity to drill long laterals. We find that to be the right answer, and especially in this particular play. Data is fairly early on that, but all the long laterals that we have drilled are outperforming initial expectations. We've got a very aggressive type curve that you can see there. So we're very excited about that ability to drill those long laterals. So we think about 2/3 of our position is currently available to drill the 10,000-footers. And so the majority of our work going into 2017 or at least 2/3 of that work will really be directed towards the long lateral type work.

Scott Hanold
Analyst, RBC Capital Markets LLC
Q

Specifically, do you find right now other operators are fairly willing? Are we at the right stage in the STACK for other operators to be willing to help do this and block up their acreage as well as yours?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

I think there's a good dialogue that's just now happening. There's a part of an industry group that we participate in with most of our larger operators in the field. They're working very well together. I think everybody is looking at operatorship. Everybody is looking at their position, trying to make sure that we take a very efficient approach.

So some of the work that you've seen us and heard us talk about with our Cimarex partner in the Woodford has been very accommodating to both the work that Cimarex does and Devon has done, bringing out the most efficient results. And I think we're just now starting to see some of those type of conversations happen with most of the operators there in the Meramec play.

Scott Hanold
Analyst, RBC Capital Markets LLC
Q

Okay, thanks. And then to follow up on the Mi Vida area again, can you give us a sense of why this has popped onto your focus? Is it some work geologically you have done, or is it more of what you're seeing from industry? Maybe this is looking at it a little bit too closely. But if I look at that map, you've got obviously some acreage outside of that little box that you drew down there. Is there any particular reason that's not included?

Tony D. Vaughn
A
Chief Operating Officer, Devon Energy Corp.

I think the one thing unique about the Mi Vida area is we've got I think about 5,500 to 6,000 net acres there, 8,000 gross roughly. So we've got a nice contiguous position in that portion of the Wolfcamp right there on the border of Reeves and Ward County. So it really sets us up for, again, a more efficient development going forward. So that's really caused us to put that on our radar screen. And we're getting a lot of good competitive data around us.

There are some good wells that are being drilled there. Again, we're trying to see and understand the vertical connectivity between that column to understand best how to develop that.

Scott Hanold
Analyst, RBC Capital Markets LLC

Q

Thanks.

Operator : Your next question comes from Peter Kissel with Scotia Howard Weil. Your line is now open.

Peter Kissel
Analyst, Scotia Howard Weil

Q

Thanks for taking my questions, maybe just another on the cost side of things, but more on the CapEx side than the OpEx side. In your supplemental presentation, you mentioned that you're proactively securing services to mitigate inflationary pressure in 2017. I was just curious if you could elaborate on that a little bit more, maybe in particular where you see the inflationary pressures and how you're mitigating that.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.

A

Hey, Pete. I'm going to introduce Sue Alberti. Sue is our Senior Vice President here that manages our marketing and supply chain groups. She's very well connected, and her group is with our operating team. So I'm going to let Sue describe some of the work that we're doing on the price of our goods and services.

Sue Alberti
Senior Vice President-Marketing, Devon Energy Corp.

A

Thank you. I'd like to say, we do think that as commodity prices improve and activity increases, we're looking to – we will get that inflationary pressure next year. We think that that could be mid to high single digits, especially in the stimulation area. And I'll tell you a few of the things that we're doing to mitigate those cost increases on the capital side. As you said, we talked about proactively securing equipment and crews at competitive prices, and we're locking in rates and terms where it makes sense given our outlook right now. So for example, on the rig side, we've locked in two long-term agreements for these rigs at current market rates.

And then Tony, talking about the LOE, said that we were unbundling the water transport and water disposal. We're doing unbundling on the capital side too in the stimulation area. And we've recently started this where we're contracting separately for pressure pumping, sand, chemicals, and diesel, taking out the markup of the bundling. And while it's new and we don't have a lot of data yet, what we're realizing what we see right now is about a 10% savings from that unbundling. So we probably will look to do maybe more of that, but we're very encouraged with those results.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.

A

I just want to add that Sue talked about probably the high single-digit type service cost increase. Again, we think we can offset that with all these internal efficiencies that we're doing. So she mentioned some of the efforts. There's a lot more than that going on, just the continuing design of the wells. I think Tony may even like to brag on a few wells we drilled recently in the Delaware. I'm not sure if you're going there, Tony, but I see you holding a piece of paper that I think you're proud of.

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

I'm trying to let you go in and say your few words and let me get it in here. Pete, I tell you I'm really excited about the work we do, and we've talked a little bit about the passion for the tentacle work that our operating teams do. On the drilling side of the business, we just stood up a Delaware rig and have now drilled three wells from spud to TD. Those used to take 17 days to complete. All three of these are averaging about 10 days now. That's really an approach to an optimized design that we've had the luxury of tying to a lot more subsurface data than we've had in the past.

It's also reflective of really the granular detail towards the execution of our business. And, Pete, I think we've talked to you about the well-con [well control] center there. So we're getting a lot of efficiencies both on the drill side of the business but also on the completion side of the business. And all that passion for data acquisition and integrating that into three-dimensional earth models and picking the right landing zone and designing more optimized or better frac designs, all that is paying off.

And we're also putting a lot of attention into the execution portion of the completion space. We monitor all the operations on the frac. We monitor all of the data on the flowback of the wells in great detail. We have also recently incorporated the coiled tubing drill-out data in our well-con center, so we think that's another potential savings there. So while Sue has mentioned that the industry is going to have some tension on cost, we think from the technical work that we're doing, we've got the ability to offset that in 2017, and very excited about additional enhancements that will be available to us for more of that type of work in the second half of 2017 and 2018.

Peter Kissel
Analyst, Scotia Howard Weil
Q

Great, Tony. Thank you, that's a great answer. One quick follow-up, more the efficiency side, though. In the STACK in particular, as activity levels continue to increase, what do you see as the biggest gating factors t here, maybe for the play in general but also Devon in particular? Is it midstream? Is it water availability? I know the play doesn't produce much water, but is there any concerns you have looking forward for any of those items?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

Pete, it's not on takeaway out of the basin. I think Sue could talk to us in a little bit of detail about that. We're not worried about that through 2017 and into 2018. A lot of the pace of activity right now is more associated with just doing good quality work, getting all the pilot work under our belt before we finalize our development plans going forward. And just like we do in all of our areas, we'll have a good build-out of infrastructure there. So we know that, say on the water handling side of the business, there could be a time when we have 20 rigs running just in STACK that there's a heavy demand on water, water handling. We'll be mimicking some of the work that we've done in the Cana-Woodford project and also in the Delaware Basin to make sure that that's very efficient, and our operating costs going forward are low and well thought through. And, Sue, I don't know if you want to add any comments to that.

Sue Alberti
Senior Vice President-Marketing, Devon Energy Corp.
A

Let me add a little bit to what Tony was saying about takeaway. We don't have any short -term concerns regarding for Devon processing or takeaway constraints in the STACK. And we have been working with EnLink to ensure that they will have adequate processing capacity for us on our forecasted production. In addition, we've got firm takeaway for our oil and our NGLs and actually until 2019 at this point.

I would say, though, that longer term when you think about the growth in this area, we think t hat there needs to be an industry solution for residue gas takeaway, and we're actively working solutions with multiple midstream companies to address this. But given the timeframe when we think that will be needed, we believe that there is enough time in order to get that in place when the growth is met.

Peter Kissel
Analyst, Scotia Howard Weil
Q

Great, thanks again, guys.

Operator : Your next question comes from David Heikkinen with Heikkinen Energy Advisors. Your line is open.

David Martin Heikkinen
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC
Q

Good morning, guys.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Good morning, David.

David Martin Heikkinen
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC
Q

One thing that we've been thinking about is the industry ramp in the Permian and just thinking about Devon's advantages around securing oil, gas, NGL, and water takeaway capacity with the EnLink relationship. Can you talk some about that over the long term with the 30% ramp in production in 2018 and beyond?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

I think absolutely it's an advantage when we're in growth plays. We have a very close relationship with EnLink. They are our midstream provider in the STACK play, and it gives us great comfort that they are. We have that relationship, so we can have teams working on essentially a daily basis on looking at what the long - term needs are and making sure that they have the right gathering, processing, and takeaway capacity at the right time to ensure that we can execute our capital plan and get our wells hooked up on a timely basis and get that value. So certainly, when you're in the growth mode in a basin, I think a tight relationship with your midstream provider is very important, and we have that with EnLink.

David Martin Heikkinen
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC
Q

A secondary thought and question, with your well-level return focus, how do you think about the shift in Devon's corporate return as you become more light oil? Just return on capital employed, or what metric should we use? And have you done any thought of well-level economics translating into corporate economics?

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

We tend to talk about the incremental well-level economics on these calls. But I can tell you that we actively look also at what we would consider full-cycle returns in each of our key project areas. Just trying to look at return on capital employed when you have all these write-offs is just – if you're just looking at that, it's hard to get a good calculation off the financials. But we look at it just from a pure rate of return, all cash spent, all cash we're getting back in each of our key plays to make sure that we're not only delivering on good incremental well-level economics, but we're from a total investment level that we're generating good returns on each area we work.

David Martin Heikkinen Q
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC

At mid-cycle…

Scott Coody A
Vice President-Investor Relations, Devon Energy Corp.

Dave, real quick. Hey, Dave, this is Scott, real quick. To further address that question, you will absolutely start seeing these high rate of return wells in the future years impact our ROCE calculations in a very positive manner. And also, another proxy for that would be on a cash flow per debt -adjusted share basis. It's certainly something that we view will be a very differentiating metric for Devon going forward.

David Martin Heikkinen Q
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC

I guess what do you think that the full-cycle returns are in your STACK and Delaware?

David A. Hager A
President, Chief Executive Officer & Director, Devon Energy Corp.

It's hard to give you that number right now because the play is still changing so much and how much incremental resource are we going to have over our original assumptions because the economics of each individual well is improving and we have a lot more wells than in our original acquisition assumptions. So it's certainly improving, but to give an absolute number I think at this point would be very difficult.

Tony D. Vaughn A
Chief Operating Officer, Devon Energy Corp.

Dave, I'll just add a little bit of a description of what we do on the operating side of the business. On a quarterly basis, we get the senior leaders from across the company together on a by business unit basis, and we do a look - back of the work that we just finished for the quarter and how that infers the forward look. We also have I think a very detailed look-back project from a project basis but also from an annual investment basis. So I think we do a really good job of ensuring that we have an accountable approach to the work that we do. It's all based on historical results shaped with a forward and continuous improvement look. So it's a pretty detailed process here in the operating teams.

David Martin Heikkinen Q
Founder & Chief Executive Officer, Heikkinen Energy Advisors LLC

Thanks, guys.

Operator : Your next question comes from the line of Matt Portillo with TPH. Your line is open.

Matthew Merrel Portillo Q
Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.

Good morning, guys.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

Good morning, Matt.

Matthew Merrel Portillo
Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.
Q

Just going back to the Woodford, I wanted to see if we could get some color or context around your development plans on the Jacobs Row, obviously quite interesting that you plan to utilize 10,000-foot laterals, but trying to get a better sense of maybe the size and scale from a section or well-count perspective that you might have in that development. It seems like it could be a pretty material growth plan for you going into 2018.

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

Matt, I think we're getting information in on the Hobson Row that will help us understand and infer the magnitude of performance improvement by going from the normal laterals to the 10,000-foot laterals. So we're going to utilize that to our advantage where we can as we go into the Jacobs Row.

So I think over 800 wells now have been drilled and completed and are producing. Each of the new vintage completions that we see, we tend to outperform the past or previous type curves. Costs are continuing to come down, so another step change here in addition to the Ricky's Ridge. And the increased oil content or fluid going forward is really just incorporating that 10,000-foot concept into the works. I think the returns on the Woodford play are beginning to shape up as being dramatically better than they have been in the past when it really has been in what we call the core portion of our field.

David A. Hager
President, Chief Executive Officer & Director, Devon Energy Corp.
A

And don't hold me to an exact number, but there are roughly 60 wells in the Jacobs development.

Matthew Merrel Portillo
Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.
Q

Great, and then just a follow-up question. We've talked a lot today about the Delaware and the STACK as your core oil developments. Just curious your thoughts on the Eagle Ford as you potentially return to activity in the play, any opportunity to continue to optimize completion designs as the basin has been in a frozen moment here for the last year or so? And are you changing any of your views on the spacing? I know that you have a new spacing design that you may be testing here with the diamond formation.

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

Matt, I'll tell you we're real pleased with where we are in the Eagle Ford. And if you go back and look at the pace of our activity, it's greatly slowed down in 2016 versus 2014 and early 2015. In fact, we were bringing on about 70 to 75 wells per quarter in that timeframe. In Q1 of this year, we were down to 22 wells brought on in the quarter. Second quarter there was only five, third quarter was only five. So we've seen the rate drop off there, but it is now stabilized, and we have four frac crews in the field that are lowering our DUC inventory down.

That's being done for a couple of purposes, but the primary purpose is to get information on the staggered lateral approach to the development, which is incorporating the upper Eagle Ford. And that information we're looking forward to having in 2017, which will shape what I think will be an accelerated pace of activity in the second half of 2017, which will have the potential for a material rate impact going into 2018. So we are looking forward. We are continuing to improve our completion designs.

Historically, we have pumped pretty much roughly a 2,000-pound per lateral foot type of job. We've moved that to more of a hybrid type fluid, and we're increasing the proppant load up to close to 3,000 pounds per lateral foot at this point, so a substantial change to the completions. The wells are just now starting to flow back on a few of those new completions. We're not ready to talk about that, but we're highly encouraged that some of the well rates that you've seen has report in the past we're going to materially beat as we go forward. So that play is setting itself up for what I think will be an accelerated ramp-up in the second half of 2017.

Matthew Merrel Portillo Q
Analyst, Tudor, Pickering, Holt & Co. Securities, Inc.

Great, thank you very much.

Operator : Your next question comes from David Tameron with Wells Fargo. Your line is open.

David R. Tameron Q
Analyst, Wells Fargo Securities LLC

Everything has been asked. I'm good, thanks.

Scott Coody A
Vice President-Investor Relations, Devon Energy Corp.

Operator, we're ready for the next question.

Operator : And your next question comes from David Tameron.

David R. Tameron Q
Analyst, Wells Fargo Securities LLC

Operator, you can move on to the next.

Operator : And your next question comes from James Sullivan with Alembic Global Advisors. Your line is open.

James Sullivan Q
Analyst, Alembic Global Advisors LLC

Hey. Good morning, guys. A lot of stuff asked and answered. I just wanted to quickly ask you guys to touch on, if you could. You mentioned it just in passing, the Powder River and [ph] they ran your rig back there (58:35), an area that you guys have spoken positively about obviously a number of times in that position over there. Obviously, you're adding the rigs, so you feel pretty good about it. What gets that area a big percentage of a limited capital pie? Is it just that you guys need a longer runway on infrastructure and permitting? I know you're looking at both those things, but what is it and what's the state of play over there right now?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.

A

James, thanks for bringing that up. We've been real pleased with the work that we've done in the Powder River Basin in the past, and we've been operating in that area for quite some time. If you recall, back before commodity prices dropped, we were drilling probably the highest return wells in the portfolio, in especially the Parkman in the Powder River Basin. And so we did take a pause in our activity as commodity prices ramped down and our focus has gone to STACK and Delaware.

We've continued to work the subsurface portion of that. We have an extensive 3-D coverage across that entire basin. So we have what I think will be unparalleled knowledge about the subsurface there. After the acquisition, we doubled our position there, and it's all Tier 1 opportunity connected. And we've got about three rig lines ready to go. It's a matter of managing the portfolio and staying within our cash flow. So we think it's a great an asset.

You've seen some transactions happen in the Powder which further confirm what we think the ultimate value in the Powder position will be. So while it won't ever have the scale and materiality that we'll see in the STACK or Delaware, it's got outstanding returns and we're looking forward to showing you additional subsurface results.

James Sullivan
Analyst, Alembic Global Advisors LLC

Q

Okay, great. Thanks, guys.

Operator : Your next question comes from Bob Brackett with Bernstein. Your line is open.

Bob Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

Q

Hey, good afternoon now, a question on the track development plan in the Delaware. Can you talk about the trajectory of wells per pad, say, last year or this year going into next year and what that steady -state number looks like?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.

A

Bob, historically and I don't know if it's more than just Devon, but the industry has really been prosecuting two and three-well pads across the Delaware Basin. And the areas where we have a larger contiguous position, we're going to employ this new design concept. And so there are up to about 14 known productive intervals in that Delaware Basin column, Bob. And so when you look at the number of unrisked locations that we've highlighted of 20,000, there's got to be a more compelling development plan going forward to accelerate present value. So that's the concept that we're looking forward to.

The way we're designing the track process, it's highly flexible between what we need to get done in the Delaware, which has some additional challenges with the federal permitting. But the concepted frac will be applied both in the Delaware and STACK on both of those STACK developments. So it's hard to tell you exactly how many wells per pad, but I can see us putting maybe up to 30 wells in a given section. We'll utilize very efficient drilling pads coupled with more of a centralized tank battery, so we'll see quite a few advantages. We've tried to highlight the advantages in our operating report, so you can take a look at that.

Bob Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC

Q

But will you do a pilot track sometime in the next years, or how do you get from where you are today to rolling out track?

Tony D. Vaughn
Chief Operating Officer, Devon Energy Corp.
A

We're going to push forward in 2017 employing this concept. We think it will be – you can call it a pilot, or really just to go forward with the development plan. We think there's a lot of flexibility in this, so we're going to be pushing forward to a more creative solution for our developments going forward.

Bob Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC
Q

And then a last follow-up, if a look at your 7.5-ish rigs for 4Q, you're calling for about $400 million in CapEx for the quarter. If I just scale that and say you're going to run double those rigs next year, and there are four quarters next year, I get closer to a $3 billion – $3.2 billion CapEx spend. But you're talking about $2 billion. How should I think about that?

Thomas L. Mitchell
Chief Financial Officer & Executive Vice President, Devon Energy Corp.
A

Yes, included in the $400 million will be also a larger component of – it will include the OBO component, plus we have other just leasehold expenditures, things like that, that are not actually Devon-operated drilling rig components. So really when you talk about going to the – and I've been talking about it on the Street for quite some time that we're going to be a run rate of around $1.6 billion with the 10 operated rigs. So going from 10 to 15 to 20, you're not increasing all these other components that are in our capital program, you're just increasing the operated rig component. And if you do the math on that, say on average it's another 7.5 rigs over 0.5 year or so, maybe that's more like four rigs. So you take four figs and average working interest, you get somewhere around that incremental $400 million to get you around $2 billion.

Bob Alan Brackett
Analyst, Sanford C. Bernstein & Co. LLC
Q

Got you, thanks for that math.

Thomas L. Mitchell
Chief Financial Officer & Executive Vice President, Devon Energy Corp.
A

Yeah.

Operator : And there are no further questions at this time. I'll turn the call back to Mr. Coody.

Scott Coody
Vice President-Investor Relations, Devon Energy Corp.

Thank you, and we appreciate everyone's interest in Devon today. If you have any additional questions, feel free to reach out to the IR team at any time, myself or Chris Carr. And once again, thank you for everything.

Operator : This concludes today's conference call. You may now disconnect.