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PRESENTATION

Operator

Welcome to the ConocoPhillips Market Update Call. My name is Hilda, and I will be your operator for today. (Operator Instructions) Please note that this conference is being recorded. I will now turn the call over to Ellen DeSanctis. Ellen, you may begin.

Ellen DeSanctis - *ConocoPhillips - SVP of Corporate Relations*

Good morning to our listeners. Thanks for joining us today to discuss this morning's press release in which we describe some further actions the company is taking in response to current market conditions. Recall we announced an initial set of actions on March 18. Like then, we're hosting a call today to discuss our rationale behind these actions and to give you a chance to ask questions of our senior leaders.

Our speakers today will be Ryan Lance, our Chairman and CEO; Matt Fox, our Chief Operating Officer; and Don Wallette, our Chief Financial Officer. We don't have any slides this morning, but we will post a replay of this call as soon as it's available.

One ground rule today, this call will address only the items from today's press release. We will not address any first-quarter items as those will be covered when we announce earnings on April 30. And then finally, we may make some forward-looking statements in today's call. As always, please refer to our SEC filings for a description of the risks and uncertainties that could impact future performance.

And with that, I'll turn the call over to Ryan.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Thank you, Ellen, and good morning. So earlier today, we announced a further set of actions that ConocoPhillips is taking in response to recent market conditions. I'll make some general comments about today's actions. Next, Matt will cover the capital and operating cost reductions and Don will cover the commercial and financial points, and then we'll go ahead and take your questions.

As Ellen said, backing up, recall in mid-March, we announced an initial set of actions to respond to the market downturn. At that time, we said we'd continue to monitor the market. We'd develop scenarios, and test our plans against those scenarios. At the time, we purposely deployed only a portion of our flexibility until we had more clarity around how this downturn would progress. Well, it's clear that since March, COVID-driven demand has continued to fall significantly. While there has been U.S. industry activity cuts and some supply adjustments from OPEC-Plus, it's not enough to balance the markets in the near term. We expect prices over the next several months will be weak and quite volatile. So we're taking actions that focus on near-term flexibility while also preserving our ability to respond further in either an up or a down direction, depending on the eventual timing and path of the recovery.

We continue to take measured actions that are consistent with our market views. And we can take this approach because we entered the downturn in a strong, relative position with significant flexibility. So here's what we announced today.

We're taking another $1.6 billion of 2020 capital cuts. Including the March reductions, we've now cut $2.3 billion of capital or roughly 35 percent, bringing our expected full year capital to $4.3 billion. We're reducing operating expenses by about $600 million or roughly 10 percent versus our initial 2020 guidance, and Matt will discuss both of these actions further.

We're suspending our 2020 buybacks after completing about $725 million of that program in the first quarter. As we've said many times, we prefer to dollar-cost-average share repurchases and level-load our capital programs through the cycles, but current prices are well outside our planning range, and we believe these are prudent levers to exercise in the circumstances.

Cumulatively, including today's actions, we've announced over $5 billion of reductions in cash uses for 2020 versus our initial plans with additional remaining flexibility. You also saw in today's announcement that we are taking actions to curtail about 225,000 barrels a day of gross operated oil and bitumen production. That's an expectation for the month of May and includes actions in the Lower 48 and Canada. Don will discuss these actions in more detail.

We are choosing to store our oil in the reservoirs instead of producing at the netback prices being offered. We are cutting back on the near-term part of our plan and conserving in places where we have the most flexibility. We're balancing liquidity preservation with a goal to retain program and organizational capacity that would allow us to resume activity quickly when warranted. And we'll continue to monitor the markets closely.

Now before I turn the call over to Matt, let me just say that our leadership team shares everybody's hopes for a swift resolution to the global COVID-19 situation. Within ConocoPhillips, we've been fortunate so far not having any significant direct impacts from the virus. I'm proud of how our organization has stepped up in the face of a big challenge, and I appreciate our workforce, our contractors, our partners, our community stakeholders and our investors for their support during this extraordinary time.

So now let me turn the call over to Matt to discuss the capital and operating cost items we announced today.

Matt Fox - *ConocoPhillips - Executive VP & COO*

Thanks, Ryan, and good morning, everyone. As Ryan said, today's actions exercise additional flexibility we have across our global portfolio. The $1.6 billion of incremental capital reductions will come predominantly from the Lower 48, Alaska and Canada segments. I'll step through those sources briefly.

In mid-March, we announced plans to slow operated development activity in the Lower 48 and anticipated some reduction from non-operated activity. That was about $400 million of the cuts announced at that time. With today's actions, we're reducing the Lower 48 2020 capital by roughly another $1 billion, including some further reductions in non-operated capital. So that's a total reduction of $1.4 billion in the Lower 48.

In terms of operated Big 3 activities, this takes our 13 rigs down to seven and our frac crews from five down to zero, and this action is designed to satisfy three objectives: preserve significant cash, avoid bringing additional production volumes online into weak near-term prices and maintain flexibility to ramp back up or ramp down further, depending on the eventual timing and path of the recovery. Because the frac phase of a well typically costs twice that of drilling yet it only takes half the time, stopping completions while continuing some drilling was the most rational thing to do in support of all three objectives. So we'll get down to four rigs running in Eagle Ford, two in Bakken and one in the Permian.

In Alaska, we announced a capital reduction of $200 million in March. And today, we're cutting another $200 million, so $400 million of cuts in total. Most of our flexibility in Alaska resides in our development drilling programs. As of this week, we'll have shut down our traditional and coiled tubing drilling activity. And we've elected not to start up the extended-reach drilling rig we mobilized to the North Slope last year. In addition, to minimize the risk of COVID cases on the remote Western North Slope, we also ended our winter exploration program early.

In Canada, we're cutting about $200 million of capital mostly driven by deferral of the next phase of Montney development. The first phase of that is going well. But we have discretion to slow drilling and the processing facility expansion, so that's what we're doing.

You saw in this morning's release that we expect to voluntarily reduce production at Surmont by about 75 percent due to very weak WCS prices on low netbacks. As a result, the need for sustaining wells is deferred, so we're also suspending sustaining capital programs in our Surmont area.

Finally, we'll make more modest changes outside North America, and we'll get some help from foreign exchange rates in the form of stronger dollar. So that describes the sources of the $1.6 billion capital reduction announced today or about $2.3 billion in total for the year.

We also announced a roughly 10 percent reduction in operating cost or $600 million versus our original guidance. These reductions are sourced from a combination of lower lease operating expenses, G&A costs and foreign exchange rate changes. Importantly, like capital, we're not taking any operating expense actions that would undermine our health and safety priorities, jeopardize asset integrity or significantly impact our ability to resume programs in the future.

But clearly, the capital and operating cost reductions will impact the 2020 production rate. Our expectation is that these reductions alone would have resulted in roughly flat average production from 2019 to 2020, but that impact will be overshadowed by the voluntary and potential involuntary production curtailments we're likely to see. So we're not providing updated guidance today on production or in any of our other typical guidance items.

And with the overall reductions in capital and operating costs this year, and using the sensitivities and differentials we provided in November, the WTI price required to cover capital in 2020 is reduced from about $40 a barrel to about $32 a barrel. And in fact, the remaining capital run rate results in a free cash flow price below $30 WTI for the remainder of the year.

So now I'll turn the call over to Don for some further comments on our commercial and financial actions.

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Thank you, Matt. I want to begin by providing some additional color on the production deferral actions we're taking in Canada and in the Lower 48. By the way, we're referring to these reductions in production as deferrals because we aren't taking actions that we would expect would impair ultimate recovery from the reservoirs.

The market typically thinks about maintaining productive capacity by drilling new wells. Curtailing production serves the same purpose but specifically retains profitable productive capacity. We think of deferrals in three buckets. First, there are involuntary deferrals. That's where circumstances such as government mandates or the lack of market access force us to shut in production. As you can appreciate, we, like the rest of industry, could see involuntary curtailments within the U.S. and internationally under current market conditions.

Then there are voluntary deferrals, and there are two types of these. One is the case where we would curtail because netback prices are less than the variable cost of operating an asset. This is what we're doing now by turning down production at Surmont. WTI prices are low, the basis differentials to WCS are high and the value of a Surmont barrel is below variable cost. This is a pretty straightforward deferral decision, and we'll turn down Surmont volumes to the lowest sustainable level without compromising the reservoir.

The other voluntary deferral is not as straightforward. This is a case where, subject to legal and contractual obligations, we can choose to curtail because there is an economic case for producing the barrel later rather than now, where the netback price today simply represents inadequate value to produce.

This is the case for our Lower 48 production deferral. We expect the upcoming months of May and June to be particularly weak for domestic pricing, with netbacks being significantly lower than the market prices. So we're planning to reduce oil production across our Lower 48 portfolio by about 125,000 barrels a day gross during May. We expect volume reductions in each of our Big 3 basins. Combined with Canada, Surmont and North America curtailments will total about 225,000 barrels a day of oil and bitumen gross for the month of May, which on a net BOE basis equates to roughly 200,000 barrels a day.

Trading for June deliveries in the U.S. begins in earnest next week, and we're expecting continued weakness. We'll have greater flexibility to curtail in June, so we could see even greater volume reductions then. As we go forward, we'll make production deferral elections on a month-by-month basis.

Our voluntary curtailment elections are currently focused on North America where we largely control the barrels and do not require a partner or government consents to defer. We view these as value preservation decisions that forego suboptimal cash flows now in anticipation of higher value later. And those opportunities are available to us because of the combination of a large, diverse portfolio and a strong balance sheet.

Let me wrap up my prepared comments with a few additional comments about our financial strength. As you know, we entered this downturn with a very strong liquidity position, with over $8 billion of cash and equivalents and a $6 billion corporate revolver that has no financial covenants. We continue to be A-rated by each of the three rating agencies. We believe we're very well positioned from a balance sheet perspective to weather a truly extraordinary situation. Coming into the downturn with a strong balance sheet plus significant cash and liquidity gives us the ability to take measured actions in response to this downturn. As Ryan said at the outset, we believe today's actions respond appropriately to our evolving view of the market but also preserve flexibility to respond further up or down as conditions change.

Now I'll turn the call over to the operator for Q&A.

QUESTIONS AND ANSWERS

Operator

(Operator Instructions) We have a question from Neil Mehta from Goldman Sachs.

Emily Chieng - *Goldman Sachs Group Inc., Research Division - Associate*

This is Emily Chieng on behalf of Neil. He just had his second child yesterday. My first question is around the production that is being ramped down in May, both in the Lower 48 and Canada. Perhaps can you give us a sense of what the level of confidence you have in bringing that production back online to full capacity or when the timing is right, perhaps from a geology or an engineering point of view, please?

Matt Fox - *ConocoPhillips - Executive VP & COO*

Emily, so you're asking about our ability to bring the production back, how confident we are in that? Is that what you're asking?

Emily Chieng - *Goldman Sachs Group Inc., Research Division - Associate*

Yes, sir.

Matt Fox - *ConocoPhillips - Executive VP & COO*

Yes. Very confident. We don't -- we're not going to shut-in anywhere that we see any risk of reservoir damage or anything that's going to impair our ability to bring it back. You can see, in Surmont, for example, we're taking the rates, as Don said, down to the lowest level that we can while still providing enough heat and pressure to the reservoir and so that we don't damage the reservoir. The rest of the deferrals are in the unconventional reservoirs, and we don't expect any issues in there at all. In fact, we expect to see quite significant flush production when those wells come back on. So no issues.

Emily Chieng - *Goldman Sachs Group Inc., Research Division - Associate*

Great. And my second question is just around Alaska. ANS pricing has obviously been quite weak recently. Are we -- are you thinking about production cuts from that region as well? And with the capital cuts that you're seeing, what does this mean for the growth in the region going forward?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Emily, this is Don. I'll respond to the ANS question, the Alaska production. Yes, Alaska is in the mix as far as the places that we would consider curtailing, at least the portion that we operate on the Western North Slope. But as we look at May netback pricing, Alaska is sold a little bit further forward than Lower 48 is and so the pricing is still acceptable to us. So we don't plan to curtail Alaska in May.

And as far as future production projections, we're not going to be in a position to provide that with all the uncertainty that we're under.

Operator

We have another question. It's from Phil Gresh from JPMorgan.

Phil Gresh - *JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst*

Thanks as always for hosting a call on this. My first question, I just wanted to clarify Matt's commentary around the breakevens. Could you reiterate that is -- that's on a WTI basis and that's to cover the dividend, the full amount? Is that a run rate event, like 2Q moving forward? Just want to make sure I understood what you meant on those breakevens.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Matt, I don't think we're enabled. Okay. (technical issue)

Matt Fox - *ConocoPhillips - Executive VP & COO*

Sorry, Phil, the -- I was making the classic blunder of being on mute while I was chatting the -- like starting a land war in Asia. Classic blunder. Anyway, the -- yes, what I was referring to was the WTI price required to cover our capital. The -- originally, the beginning of the year with our original capital guidance, that was around $40 WTI for the year. Now it's $32 with the new capital guidance. That's the average for the year. Then I also referred to, on a point forward basis, the run rate that we'll have to -- the average through the next three quarters is actually below $30 WTI to cover that run rate. Is that clearer?

Phil Gresh - *JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst*

Yes. Yes, very clear. And any additional -- go ahead.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Yes. Sorry, Phil. It's Ryan. And that -- yes. So that's just to cover the capital program. It would take $6, $7 additional to cover both capital and the dividend.

Phil Gresh - *JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst*

Yes. Yes. Okay. Second question is any, I guess, color on these curtailments that we should think about by assets, particularly in the Lower 48?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Phil, we're not going to provide a field-by-field breakdown of the curtailments at least as far as these estimates for May. Of course, you'll see the actuals when they get published. But I can say that for each -- they'll be across each of the Big 3 as well as Permian conventional. And they'll be significant in each.

Phil Gresh - *JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst*

Okay. Last quick one. Can you give an update on the Australia West timing? Is that still on track for the first half of this year? Or any updates you can provide?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Yes. Both we and the buyer remain committed to the sale. We continue to make progress, and we expect it to close in the second quarter.

Operator

Our next question comes from Roger Read from Wells Fargo.

Roger Read - *Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst*

Hopefully, everybody can hear me.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Yes. We hear you, Roger.

Roger Read - *Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst*

Okay. Great. I guess one of the things I'd like to follow up on is we think about, as you mentioned, greater flexibility in June on some of these shut-ins. How much of this is driven by partner issues? Or as the operator, you essentially have the flexibility, I guess, would be the right term to do shut-ins as you see necessary.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Yes. Roger, we're -- these are largely operated by ConocoPhillips, and we own them 100 percent. So these are actions that we're taking that we can control.

Don Wallette - *ConocoPhillips - Executive VP & CFO*

You could also add, Roger, that we're only referring to ConocoPhillips-operated production here. We really have no insight as to what some of our non-operated operators may be choosing to do. So we could see curtailments on properties that we don't operate but participate with a working interest.

Roger Read - *Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst*

Could you give us an idea of the breakdown within Lower 48 of operated versus non-op and just to kind of help us think about some of the moving parts in the future?

Matt Fox - *ConocoPhillips - Executive VP & COO*

Yes. Generally, we're close to 100 percent operated in the Eagle Ford and most of the Permian unconventionals. The Bakken is where we have significant operated production by other operators. And it's about 40 percent of the Bakken, as I recall.

Roger Read - *Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst*

Okay. Great. And then last question I had for you just because a lot of your descriptions have been in an oil term. Should we think of this as oil equivalent? Or are we thinking about this as oil only? So when I think about the 200,000 net, do I need to assume an NGL and gas impact there as well?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Well, Roger, the 200,000 was a barrel oil equivalent figure, and that was a net BOE figure. I don't have a breakdown by component on that.

Operator

Our next question comes from Doug Leggate from Bank of America.

Doug Leggate - *BofA Merrill Lynch, Research Division - MD and Head of US Oil and Gas Equity Research*

Let me add my thanks to you guys offering some clarity amongst all the fog that we're dealing with right now. So just two quick questions. I guess the big picture question, Ryan, is when you say you're not going to provide any additional guidance items at this time, does that mean that we need to kind of reset the 10-year plan?

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Not necessarily, Doug. I think certainly, the near-term part of the plan, we're taking some actions to reduce that. But we're maintaining the flexibility, as we said, both organizationally and where we're making the reductions that we're taking to return to that scope that we described in the 10-year plan. So certainly, some near-term impacts. But no, our intent is if/when prices recover back to a reasonable level, we would get back on to that plan.

Doug Leggate - *BofA Merrill Lynch, Research Division - MD and Head of US Oil and Gas Equity Research*

Okay. Matt, and forgive me for being dense, but can you just spell out for us what is the run rate CapEx in the second half? And if I may do a part B to that, the OpEx reductions that you mentioned, should we think of that as sustainable or those costs go back up again when oil prices rebound? And I'll leave it there.

Matt Fox - *ConocoPhillips - Executive VP & COO*

Yes. Doug, the -- yes, what I was referring to on the run rate for capital was, if you take $4.3 billion of operating plan capital on average for the year that we're now planning and if you assume that it's roughly $1.6 billion was spent in the first quarter, the -- just as -- that's in line with the guidance that we gave at the beginning of the year, then that would give you $2.7 billion remaining, which is, on average, $900 million a quarter. So that was what the basis was. So that's a run rate equivalent of $3.6 billion for the year, which is pretty close to our sustaining capital level if you'll remember. And so that's the number. That's the basis that I used to calculate the less than $30 free cash flow price required to cover that capital for the remainder of the year.

In terms of the operating cost, the -- some of these reductions are reductions that we would not anticipate maintaining in a higher oil price environment. For example, we're going to slow down well work and workovers. We're going to accept lower operating efficiencies in a lower-oil-price environment. In a higher-price environment, we would want to get back to producing at our optimum capacity for the higher-price environment. So I wouldn't see these as sustainable operating cost reductions. They're really done in response to the current circumstances.

Operator

Our next question comes from Josh Silverstein from Wolfe Research.

Josh Silverstein - *Wolfe Research, LLC - MD and Senior Analyst of Oil and Gas Exploration & Production*

Just a question on the supply curtailments. What's the decision or the key drivers that go into the decision-making to bring volumes back online? Is it simply having a buyer or price? What are the two or three variables that go into this decision?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Yes. Josh, I would say that the key variables, we're not going to -- we like to be transparent, but we don't like being very transparent about how we think about pricing. We're in the market every day buying and selling petroleum. But yes, I'd say the key variables are maybe the obvious ones.

They're going to be what's the available price for us to sell on that day and what's our view of future prices. And the bigger the gap there, then the more willing we'll be to -- or the smaller the gap, the more willing we'll be to sell oil.

Josh Silverstein - *Wolfe Research, LLC - MD and Senior Analyst of Oil and Gas Exploration & Production*

Got it. Got it. And then, Matt, you had mentioned still running some rigs on the backside of this, I'm guessing, building up some backlog here. Is the thought at least right now to try to have kind of a stabilized Lower 48 production base on the back side of this? Are you even thinking about trying to set up the asset base to -- the Lower 48 base to grow for 2022 again? How are you just trying to think about that setting up for the future right now?

Matt Fox - *ConocoPhillips - Executive VP & COO*

Josh, we're not really focusing on sustaining flat production in any particular area. As I said earlier, we're down roughly to a sustaining capital level on a run rate basis. But that doesn't necessarily mean it will be sustained in any individual segment. We are going to be building some DUCS, obviously, as we go through the remainder of the year. And that gives us the flexibility if we choose to ramp up production relatively quickly, or not. We could just complete those wells at a regular pace. So we haven't really decided yet because market conditions will give us a guide as to what makes the most sense to do as we start to move out of this lower-price environment.

Operator

We have a question from Alastair Syme from Citi.

Alastair Syme - *Citigroup Inc, Research Division - MD & Global Head of Oil and Gas Research*

Can you just explain to me some of the pitfalls (inaudible) from curtailing or shutting in the Lower 48? Are you choking back on individual wells? Or are you shutting in entirely? And then so what happens as you go into June? Do you need to start to cycle of some of this inventory round for reservoir reasons?

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Well, Alastair, thanks. Yes. No, we've got a pretty specific set of protocols that we're using in the Lower 48. So we've identified the wells we can shut in that we think can come back relatively quickly. And as Don and both Matt have said, we didn't want to reduce the productive capacity that we have to return production and even expect flush production as we turn them back on. So it should come back relatively quickly.

Alastair Syme - *Citigroup Inc, Research Division - MD & Global Head of Oil and Gas Research*

And you could leave that shut-in for a month or so? Or would it -- is there a timeline?

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Certainly, the unconventionals. Absolutely. Yes. No, we're not time-bound-driven. And we have to probably, for contractual reasons, rotate things around a little bit to make sure we're still holding things in good stead on our leases. But that's all quite manageable.

Operator

We have a question from Paul Sankey from Mizuho Securities.

Paul Benedict Sankey - *Mizuho Securities USA LLC, Research Division - MD of Americas Research*

I hope you're all well. Could you talk a little bit about how you guys -- are you storing a lot of oil? And can you talk a bit about any pipeline commitments or impact on pipeline commitments you may have? And the original question was just are you placing all your oil? Or are you building up inventory here?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Paul, we're not storing a significant amount of oil above ground. We prefer to avoid the -- we've got the cost of transporting the oil to the storage facility, the storage fees themselves, the cost of getting it back out, transporting it back to customers. And so we're choosing to store our oil in the field, in the reservoir instead. And as far as pipeline commitments, yes, we have pipeline commitments. I'm not going to get into all the details, but we believe that we can manage around that. We have a quite capable commercial organization that's able to backfill volumes that we don't flow. And so we don't expect significant costs associated with those commitments.

Paul Benedict Sankey - *Mizuho Securities USA LLC, Research Division - MD of Americas Research*

And then the theme of your analyst meeting was lowest-cost production. Can you sort of at a macro level characterize where you think you sit relative to the U.S. industry here? Do you feel that the industry is being slow to shut down production? What are you seeing competitively around the place in terms of how you would expect the industry to respond to this crisis and the extent to which you're ahead of that curve, which I guess is what I'm driving at.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Yes. I think, Paul, we -- I would expect you're going to see a lot more of this. I think, as Don described, there's probably some involuntary actions coming as inventories build and there's no place to move the crude. Whether you're inland or on the water, it's not going to matter as these inventories reach tank top. So I think our ability to maybe go a little bit earlier on this is, I think, evidenced by our strong balance sheet and the flexibility that we had coming into this downturn and the capability that we've got as a company. And we're just not going to sell our crude for these kinds of prices and think as the COVID situation works itself through the economies here in the U.S. and globally that demand will start to return and there's better prices in the future for us.

So we're just not going to -- we're not going to choose to sell our oil at these kinds of netbacks. And maybe some people can do that, some maybe not, because the dollar cash flow is going to be what they need because they don't sit in the same sort of financial position that we are as a company. But I think generally, across the industry, we're going to see more of this as we go forward.

Operator

We have a question from Scott Hanold from RBC Capital Markets.

Scott Hanold - *RBC Capital Markets, Research Division - MD of Energy Research & Analyst*

I apologize. My line has been going in and out. So if I had missed -- I may be asking a repeat question. If I do, just let me know. When you step back and look at your decisions to reduce mostly in the North American area versus internationally, does that indicate that there's a bit of higher sensitivity to pricing in the North America versus internationally? Or is it just primarily focused on where you operate and where you don't?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Scott, yes. I think as we mentioned, we're going to be taking a look at this on a month-by-month basis. And so we're focused on May right now. And the prices that we're seeing internationally are a little better from a netback standpoint. So even if we had complete control over our international assets, we probably would not choose to curtail. A lot of the places where we operate, it's the governments that are making those decisions on a national basis. So we may see actions in some places where we operate internationally. But for now we're focused on where we can control the decision and control the barrels, and that's in North America.

Scott Hanold - *RBC Capital Markets, Research Division - MD of Energy Research & Analyst*

Okay. Understood. And then my follow-up is in one quick piece. And Matt, you made a comment about, I think -- and I again apologize. My line just went out when you were saying that, but based on your new capital spending plan, that it's pretty much on a relative basis at maintenance mode, obviously, ex curtailment. I think you indicated that. Is that correct?

And then also, if you could make a comment on if you think the U.S. should do proration as being discussed in Texas and maybe Oklahoma right now?

Matt Fox - *ConocoPhillips - Executive VP & COO*

So I'll take the first part of that and then hand over the sort of the more political question to Ryan. But the -- I think what you were asking, Scott, and it broke up a little bit, was for me to confirm that I said that this, absent any curtailment, we would be roughly flat from 2019 to 2020. So if that was the question -- and I'm sorry. I didn't hear it clearly. Then I can confirm, yes, that's roughly what we'd expect absent any curtailment effects. And the -- although we're not giving any definitive guidance going forward, such as assuming so many uncertainties. But directionally, that's the implication of the capital and operating cost reductions for production.

Ryan Lance - *ConocoPhillips - Chairman & CEO*

Yes. And Scott, on the second piece, we didn't support the action that the Texas Railroad Commission was hearing in terms of forced curtailments across industries or across all of Texas. We think the market is working and will work, and we're going to see probably more of what we've been talking about today in terms of deferrals coming, whether they're involuntary or voluntary with the way -- everybody saw what the inventory build was last week, and we expect that to continue. And like most people are predicting, we'll reach inventory fill sometime in May. And the markets are going to make this happen.

Operator

Our next question comes from Bob Brackett from Bernstein Research.

Bob Brackett - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Research Analyst*

I think a number of my questions have been asked, so I'll ask a somewhat wonky question on Surmont. So what is the process of shutting in a SAGD? Are you shutting in phases? Are you shutting in pads? How do I think about the steam-oil ratio? Are you still injecting sort of 3 units of steam for every unit of oil? And finally, what's that sort of split between, call it, fixed OpEx and variable OpEx for that operation?

Matt Fox - *ConocoPhillips - Executive VP & COO*

Yes. Bob, maybe I'll take that. The -- yes, in Surmont, the -- because it's a SAGD operation, some of the pads, some of the well layers require continued steam to maintain the temperature and the pressure. And some of them, for example, have overlying water. And you want to make sure that you're holding that overlying water back by continuing to put steam in the steam chambers. Some of the steam chambers that are less mature have less overall heat in them and, therefore, require a bit more heat to stop the water from condensing. So basically, what we can do or our guys in Canada can do is they can basically move from well to well and make sure that they're managing that such that we don't have any flooding of the injectors by water that's condensing. So it's an active process, an active management process. And the 35,000 barrels a day gross it would come down to, we think, is the minimum that we need to maintain production.

In terms of variable operating cost, in Surmont, the variable operating cost is roughly $4 a barrel. The -- it's mostly gas cost.

Bob Brackett - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Research Analyst*

And what was the fixed OpEx per barrel be then?

Matt Fox - *ConocoPhillips - Executive VP & COO*

So the -- I don't have the fixed OpEx off the top of my head. Actually, we've been looking at the variable recently. So I can't give you that number right now.

Bob Brackett - *Sanford C. Bernstein & Co., LLC., Research Division - Senior Research Analyst*

Okay. I appreciate the technical and economic details.

Operator

We have a question from Ryan Todd from Simmons Energy.

Ryan Todd - *Simmons & Company International, Research Division - MD, Head of Exploration & Production Research and Senior Research Analyst*

Maybe a follow-up on the previous question on Surmont. As you think about the eventual ramp-up in production on the other side of this, how much does time of shut-in have an impact on the eventual ability to re-ramp and the cost of re-ramp? Is it different if it's shut-in for a month or six months? And what sort of process will you potentially have to go through to get things ramped up there?

Matt Fox - *ConocoPhillips - Executive VP & COO*

We'll be able to ramp up relatively quickly. Within a month or so, we should be able to get ourselves back up to the earlier operating conditions. We have -- I mean we do have experience of unplanned significant shutdowns in Surmont, as most oil sands producers do because of the occasional wildfires that pass through there. So we do have a flexible enough plant and then the operators that are experienced in bringing these back on. And so we don't anticipate a long lag from -- to get back to full production when we -- when the market conditions are right for that.

Ryan Todd - *Simmons & Company International, Research Division - MD, Head of Exploration & Production Research and Senior Research Analyst*

Okay. That's helpful. And then maybe as a follow-up, I appreciate all of the clarity and some of the drivers that you provided for us in terms of the curtailments. I guess as we -- as I think about the volumes that are being curtailed in the Lower 48, the 125,000 barrels a day, how -- is there an operational driver behind that number? I mean why 125,000 versus 150,000 or 75,000 is -- or is that like a preemptive number that you would hope to avoid involuntary curtailments in the future? I guess anything more in terms of, I guess, maybe your ability to cut further why that number?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Yes. Ryan, I can give you some additional color around that, I guess. As we -- trading for May deliveries begins in -- or began in the second half of March, and we began trading oil, entering into contracts for deliveries in May back then. And I wouldn't say that prices were good, but they were tolerable. And then as we moved in further into the trade month, prices continue to deteriorate rather rapidly. So by the time you got to April, the prices we were seeing were just not acceptable to us. So as far as the 125,000 for May, a lot of it has to do with how much volume we had committed when prices were acceptable to us and how much remained unsold when prices fell below our tolerance point, I guess.

Matt Fox - *ConocoPhillips - Executive VP & COO*

And I guess that's why June barrels, there may be more deferrals, as you said, Don, in your prepared remarks?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Right.

Operator

Our next question comes from Michael Hall from Heikkinen Energy.

Michael Hall - *Heikkinen Energy Advisors, LLC - Partner and Senior Exploration & Production Research Analyst*

Hope everybody's staying safe and sound. I guess I just wanted to -- we've hit a little bit on the kind of thought process or sensitivities and approach to thinking about bringing back the deferrals but -- on the volume side. But I was curious on the completion side, you dropped to zero frac crews. Is it assumed within the current capital budget that that remains a zero through the course of the rest of the year? Or do you assume you'll bring some completions back by year-end with the current round of the capital budget?

Matt Fox - *ConocoPhillips - Executive VP & COO*

Essentially, it assumes that we won't bring the completion crews back this year. I think we maybe assumed that we will gradually ramp in towards the end of the year but the -- but for all intents and purposes here, you can assume that the completion crews are not coming back this year. Obviously, we have the flexibility to change that if circumstances change, but that's the essence of the -- probably a current capital estimate.

Michael Hall - *Heikkinen Energy Advisors, LLC - Partner and Senior Exploration & Production Research Analyst*

Okay. That's helpful. And then I'm curious too on the production deferral side. Obviously, it sounds like, certainly, on average, the Lower 48 impacts are of the voluntary and let's say non-operating cost-driven sort. But are there any areas within the Lower 48? Specifically, I'm thinking about the Delaware Basin where I'm assuming you have some exposure to WTL pricing. Are there any areas there that were not covering operating costs and hence more similar to that first bucket of the voluntary curtailment that you talked about? And then similarly, are there any API discounts that you're seeing in the Eagle Ford or anywhere else within the portfolio?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Michael, again, we're talking specifically about our outlook for pricing in May. And for each of our Big 3 basins, our cash operating costs are a good bit lower than the netback pricing that we see that's available. So this isn't a case where we're curtailing because we're not covering either variable or total cash cost. We could do that and clear that by a margin. We're just simply not accepting the netback prices that we're seeing that's not profitable enough for us.

Michael Hall - *Heikkinen Energy Advisors, LLC - Partner and Senior Exploration & Production Research Analyst*

Okay. And I guess just -- are you seeing any high-gravity discounts in areas like the Eagle Ford or Delaware or anywhere else in the portfolio?

Don Wallette - *ConocoPhillips - Executive VP & CFO*

Everywhere where we're producing condensate, we're seeing high-gravity discounts. Yes.

Operator

At this moment, we show no further questions. I would like to turn the call back to Ellen for final remarks.

Ellen DeSanctis - *ConocoPhillips - SVP of Corporate Relations*

Thanks, everybody. And stay safe and stay well, and we'll be announcing earnings at the end of the month, and we'll give you more information as we know it at that time. Thank you.

Operator

Thank you. Ladies and gentlemen, this concludes today's conference. We thank you for participating. You may now disconnect.
