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PRESENTATION

Ellen DeSanctis ***ConocoPhillips Company - SVP of Corporate Relations***

Good morning, everyone. My name is Ellen DeSanctis, and I'm the Senior Vice President of Corporate Relations for ConocoPhillips. Our entire executive leadership team is here this morning. And on behalf of all of them, it's my privilege to welcome you to our 2019 Analyst & Investor Meeting.

I'm going to quickly review today's agenda. Ryan Lance will begin by reaffirming the value proposition we launched three years ago, and he will present a highlight of today's 10-year plan. Matt Fox will describe our differential strategy and portfolio. These form the foundation, the basis, for the plan -- the investment plan you'll see today. Next, you'll hear from our three region presidents. They will provide asset-level details on each of their areas. You'll hear from Bill Bullock, who'll cover the Asia-Pacific Middle East region, you'll hear from Michael Hatfield, who'll cover the Alaska, Canada and Europe regions. We'll take a short break after Michael, and then we'll resume with Dominic Macklon, who will cover our Lower 48 region.

Don Wallette will summarize the financial details of our base plan, and he will address how our plan performs across price cycles. Ryan will come back for some closing comments and then we'll host a question-and-answer session.

Today's meeting is all about our compelling future. So we will make some forward-looking statements today. Actual results could differ materially from the projections that you see. The risks and uncertainties in our future performance are described on the cautionary statement shown here and in our periodic filings with the SEC. We will also use some non-GAAP measures today. Reconciliations to the nearest GAAP measure can be found in the appendix section of today's material. Again, welcome. Thank you for your interest in ConocoPhillips. And now it's my pleasure to turn the meeting over to Ryan Lance.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Thank you, Ellen, and good morning. I want to welcome our guests to our meeting and our listeners that are online. Certainly pleased to host this year's analyst meeting on our home field here in Houston. So today, as Ellen described, we're going to lay out a plan that we believe is one of the boldest, yet the most sustainable, plan of any company in the E&P industry. Our plan is based on our approach to running an E&P company that is built upon free cash flow generation, peer-leading return on capital, and of capital, but not just for one year or two. Today, we're presenting a 10-year plan. A plan that is powerful, sets us apart and clearly demonstrates our commitment to long-term value creation for all of our stakeholders. Now I'm going to start with a chart that none of us can ignore. And it's shown here. Three years ago, we launched a new value proposition based on two fundamental premises: The first was that this business is entering a new normal of lower, more volatile prices. The chart on the left clearly demonstrates that this has continued. In the early part of the decade, oil prices averaged about $100 a barrel and varied about 10 percentage points. Over the past few years, the oil price has averaged in the low $50 per barrel, but it's cycled up and down across a much broader percentage range; the second premise was that our industry faces a flight of sponsorship by investors. The chart on the right paints a picture of a sector that will struggle for relevance unless the industry can create value on a sustained basis.

Now we took these two premises head-on in 2016 when we reset our value proposition. We understood that to win in a volatile business, it's critical to deliver consistent performance through the cycles, be resilient to the low prices and retain full exposure to the upside. As for regaining market confidence, the key is to know what matters to investors. And for our sector, what matters is disciplined capital allocation, returns on capital, returns of capital to our owners and responsible execution. These two premises were top-of-mind in 2016 and they remain top-of-mind today.

Since 2016, we've delivered performance that consistently exceeds these premises. And the plan you'll see today premises -- demonstrates our ability to sustain this performance for a decade. That's why we believe we can thrive in a volatile business and attract investors to ConocoPhillips for the long term. Since the time of the value proposition reset, our strategic objective has been clear: To deliver superior returns to our shareholders through the cycles, and we've designed our strategy, our principles and our priorities to satisfy this objective. The strategy addresses three distinct challenges in our industry today: Price uncertainty, capital intensity and maturity. Now these represent a challenging backdrop for any commodity business, but we believe we offer an investment approach that is aligned with these realities.

We addressed price uncertainty by having a low cash flow breakeven price and maintaining financial strength. We know these are differentiators in a commodity business. We're in a capital-intensive business. To thrive in that reality, our strategy framework includes having a world-class, diverse, low cost of supply portfolio, but that's not enough. Our strategy requires us to optimize our investments to lower our capital intensity. That's how we avoid getting trapped on that treadmill that has dogged our industry.

Now for those that are paying attention, that's the first time I've mentioned cost of supply. We kind of like that term. So Mr. Sanky, the over-under is 70, if you want a bit of the action.

Unidentified Participant

(inaudible)

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Now finally, we want to address maturity in the business by frankly acknowledging that it is mature. In any mature business, it's essential to stay disciplined and allocate capital to deliver strong free cash flow and returns on, and of, capital. In the middle column, we show our principles that are foundational for our company. They're to keep a strong balance sheet, grow cash flow on a per-share basis and generate peer-leading distributions to our shareholders, and financial returns are at the center because that's what matters over the long term.

And on the right side are the five clear priorities for capital allocation. They have not changed. Our first priority: Maintain production and pay our existing dividend, which we raised by 38%; then we want to grow our per-share dividend at a competitive rate, which we've done; third is to have an A-rated balance sheet. That's what we have; and fourth, to supplement our dividend with share buybacks in order to return more than 30% of our cash flow from operations annually, which we have consistently exceeded; and finally, we'll invest to expand cash flows but not at the risk -- at the expense of returns.

Now we believe our strategy, our principles and our priorities are the right ones for this business. They're at the heart of our value proposition and they're what's guided us into an advantaged E&P that we are today. You'll recall that when we launched our new approach in 2016, it required a significant transformation inside ConocoPhillips to improve our underlying performance. Our efforts touched virtually every aspect of the company. Now this slide presents our three-year transformation on a page. It compares the

ConocoPhillips of three years ago on the left to the ConocoPhillips of today on the right. Our production base is smaller due to asset sales of about $20 billion, but the high-graded portfolio is now generating stronger underlying performance. Our free cash flow yield was zero in 2016. In 2019, we are estimated to generate a free cash flow yield of 9%, which is strong for any company in any industry. We also significantly strengthened our balance sheet. Net debt in 2016 was $24 billion and it's estimated to be roughly $6 billion by the end of this year. That's as strong a balance sheet as you'll find in this business today.

In late 2016, we activated our new return of capital program consisting of a more affordable dividend with buybacks. That year, our total return of capital to shareholders was equivalent to $1.10 per share or about 28% of our CFO. In 2019, we expect to return $4.45 per share, representing over 40% of our CFO.

Over this time frame, our resource base has grown and gotten better. Despite production of 500 million barrels and asset sales, our resource with less than $40 per barrel WTI cost of supply is 50% bigger now than it was in 2016. But the proof of our transformation shows up in our capital efficiency. From 2016 to now, our return on capital employed has made a complete turnaround and it's not just from price, it's underlying. The improvement from minus-4% in 2016 to the expected 12% this year significantly exceeds the implied impact from the price improvement over this period.

Financial return is our North Star. The improvements across all these metrics set the stage for the 10-year plan that you'll see today. We're stronger now than we were three years ago, and we plan to get stronger over the next decade, and we'll keep our focus on these drivers of value. I would be remiss if I didn't recognize the significant efforts of our workforce over this time frame. Their commitment and dedication made our transformation possible. They did the heavy lifting and they delivered the results. As I said a moment ago, you need the right strategy, the right principles, the right priorities for this business, but you also need a great workforce, and we have one.

Now in a moment, I'll summarize our 10-year plan and then turn the meeting over to the other speakers. Before I do, I want to take a moment to acknowledge the aspects of ConocoPhillips that really transcend the numbers. Yes, we believe we have an important role to play in delivering affordable energy to all four corners of the world. But we must do that in a way that works for all stakeholders, for our investors, for our workforce, for our neighbors and for our partners, and that means doing things the right way.

At ConocoPhillips, we take accountability for our strong financial and operational performance, but we also take accountability for greater responsibilities. Performance with a purpose is core to ConocoPhillips. We are widely recognized as a leader in environmental disclosure and performance. External recognition includes our standing in the S&P 500 ESG index as well as the Dow Jones Sustainability Index. We were the first E&P company to set an emissions intensity reduction target. We also lead the pack on social and governance issues with support from an engaged and diverse Board of Directors.

Our Board and management team recognize to compete against the broad market for investor attention, so we're adding the S&P index to our performance peer group. And we continue to up our game on disclosure.

Now in addition to having a strong focus, we're going all-in on the digital transformation. For example, we're implementing robotic process automation in our back-office functions. We're advancing artificial intelligence, deep learning and machine learning for emissions monitoring and seismic advancements. We're using predictive analytics across our operations and our planning processes, and we're doing these in partnership with some of the most innovative companies in Silicon Valley and the top-3 global cloud leaders. But everything we're doing on this page, just like the plan you'll see today, recognizes a -- requires a world-class workforce, one that is diverse, inclusive, engaged and has the skills for the future.

At ConocoPhillips, we take pride in having a strong culture based on our SPIRIT Values: It's safety, it's people, it's integrity, responsibility, innovation and teamwork, and that's who we are.

So today, we're showcasing a powerful plan that sets us apart from the industry. This is our plan on a page. It's about as simple as we can make it. The punchline, at a reference price of $50 per barrel WTI real, we expect to generate $50 billion of free cash flow over the next 10 years, while staying resilient to the downside and fully exposed to the cycles.

Let me step you through the math. Over the planned period, we expect to generate about $120 billion of cash from operations. That's shown in the green bar on the left. Moving to the next bar, we plan to invest $70 billion across our existing portfolio. That's in that dark blue wedge. On top of the capital, we show our projected dividend outlay of approximately $20 billion. Now that reflects a 38% step-up in the ordinary dividend, and assumes we grow the dividend rate in line with our cash flow growth and the dividend growth rate of the broader market.

On top of that, you can expect and see that we repurchased $30 billion in shares over the next 10 years consistent with our commitment to return of capital greater than 30% annually. And after all that, based on our projections, we will even have some cash to spare. Off to the right, I've listed some of the key outputs of this plan. For about $7 billion of CapEx per year, we expect to grow our production 3% annually. We believe this is rational for the mature industry that we're in. The 10-year capital program can be funded at an average cash flow breakeven price of $35 per barrel WTI, which we believe is peer leading. Our balance sheet maintains an enviable leverage ratio of net debt to CFO of less than 1 turn. And based on this plan, we exceed our distribution targets over the next 10 years. And most importantly, we expect to grow our return on capital employed by 1 to 2 percentage points each year. That's a powerful plan for a company our size, and we challenge any other E&P company to show you a plan like this.

Now of course, today, it is a plan. It was built bottom-up by rigorous selection and investment phasing of our existing inventory. So it does not include investments in resources we currently don't have captured in the portfolio. Likewise, it's based on a reference price that will, no doubt, cycle higher and cycle lower. So as opportunities arise to add resources that are accretive to our value proposition. Or as prices cycle, you should expect this plan to be optimized using the same principles that we've laid out here today. And only to make it better. Of course, we know the future is full of uncertainties, but there's one thing you should be certain about, and that's our commitment to long-term value creation. Our mission for today and for the next decade is to demonstrate that across the cycles, we have the strategy, the portfolio, the financial framework, the world-class workforce to be the best E&P investment for all of our stakeholders.

So now let me turn the meeting over to Matt. He's going to give you a deeper dive into our view of scenarios and our strategy as well as a deeper view of the portfolio.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Thanks, Ryan. Good morning, everyone. So I'm going to introduce the operating plan that results in the $50 billion of free cash flow that Ryan just described. But I'm going to start by explaining the underlying philosophy behind our strategic planning process, how we've chosen what we believe is the optimal portfolio for this business, and I'll finish with a look at the 10-year plan.

Now our planning process is designed to acknowledge and prepare for the inherent uncertainty in our business, including testing the strategy across a wide range of scenarios. Over the last several years, the portfolio choices that we have made have reshaped our asset base to focus on diverse, low cost of supply and low-capital-intensity assets. I'll describe the resulting portfolio that forms the foundation of the plan. I'll finish by explaining our approach to capital allocation across the coming decade, how we intend to optimize the pace of development within our assets, how we'll optimize that across the portfolio, and then why we believe this will result in the $50 billion of free cash flow. So let's start with our planning process.

We see strategic planning in the context of an approach to managing our business as a whole that covers strategy, execution and accountability, because all three need to work together to consistently deliver superior returns. I'll start with strategy. Our whole strategy process is based on a recognition of the strategy paradox. And that paradox says that to have a differentiated, successful strategy requires commitment, but that commitment needs to be made into the face of a very deeply unpredictable world. So how do we resolve this fundamental paradox for our business? Well, it starts with a thoughtful examination of the different external worlds we could be facing. In other words, alternative scenarios. I'll get into that in more detail in the next two slides.

The second fundamental underpinning of the strategy is a clear set of objectives and priorities. As Ryan said, our priority is to deliver superior returns to shareholders through cycles, and we have clear and consistent priorities that Ryan also just described. We then consider different sets of coherent choices that could meet these objectives and then how they would perform across the scenarios. To facilitate the process, we have a proprietary planning tool that allows us to consistently and thoroughly model different portfolio and capital allocation choices and then test them across these scenarios. We use cost of supply as the primary allocation decision criterion for capital. There's no news there, but I'll refresh your memory in a few moments on what we mean by cost of supply.

And importantly, we discuss the uncertainties and alternatives in full collaboration with our Board all the way through the year. But great strategies are of little value without great execution. Now I won't dwell on the elements of this because they're pretty much self-evident, and we have a strong track record of safe, consistent and environmentally sound execution that you're all familiar with. And then finally, we need to hold ourselves accountable for the results of the strategy and the execution. What we did right and what we can learn from that. And importantly, what we got wrong and what we can learn from that. I'm going to give you an example of something very important that we learned from one of these look-backs later in the presentation. This is all done consistently and rigorously throughout the year with after-action reviews and formal look-back process for the Board. And of course, accountability is a key part of our compensation system. The whole cycle is highly integrated, rigorous and embedded across the whole company because we recognize it's critical to our long-term success.

So let's go back to the beginning and talk about resolving the strategy paradox. Starting with how the world might play out over time and the associated implications for strategy. Now I don't need to tell you, but the world faces an uncertain future. Here's our data on how changes in population, the size of the world economy, energy demand and carbon emissions have played out over the last 30 years, and here are third-party projections of how they may change over the next 30 years. And we believe looking at uncertainty over this time horizon is required for strategic planning and these ranges represent some pretty profound uncertainty in some pretty fundamental variables for our industry. Now these are uncertainties that influence the outlook for all businesses and governments across the world, and they could lead you to raise your hands up in dismay, find a dark corner to crawl into, but that's a reaction that we try to avoid. We'd rather embrace this uncertainty and gain insights into what decisions we should make to set the company up for success in any future.

But by themselves, these sort of high-level views of the world aren't particularly helpful for a strategic planning process because they're inadequately specific to our business. So they don't provide enough granularity to help with decision-making. So how do we develop our scenarios? We use our proprietary tool that allows us to view comprehensive ranges of scenarios focused across the dimensions that we believe will have the biggest impact on energy supply and demand over the next 30 years. In our view, those are trends in technology, government policy and consumer behavior. Examples of key technology trends include the cost of supply for oil and gas, nuclear and renewables, the cost and capacity of energy storage and the cost of carbon capture, to name a few. Examples of significant government policy decisions include OECD fiscal policies like carbon tax and the pace of non-OECD climate action. And consumer elements include trends in urbanization, mass transit, ride sharing. We then build a model using third-party internal supply-and-demand projections and correlations that allow us to assess different rates of change in each of these dimensions and the elements within them and understand the interaction between them over time. We can then model specific combinations of parameters that could transpire. So for example, the degree of penetration of electric vehicles by 2050 will have a profound impact on demand for oil. We've modeled that range. The magnitude and adoption pace of carbon pricing could shape the future supply and demand for fossil fuel and renewables. We've modeled that range too. And if consumers fully embrace ridesharing and the current trends in urbanization continue that could significantly impact vehicle miles traveled. And we can model all of these ranges and many, many more and they can result in literally thousands of scenarios.

Now based on our current scenario range, oil and gas remain a significant part of the energy mix through 2050. And over that period, we see oil prices averaging between $40 and $70 a barrel. That range represents about 80% of the outcomes, so there's a chance that the average could be above or could be below -- above $70 or below $40. But bear in mind, this is the range of uncertainty in the average price that comes from our scenario model, not the range of outcomes in any given year. Cycles and volatility will remain and the range could be significantly wider in any given year.

With such a wide range of potential outcomes it's critical to have a system in place that tracks trends in the individual elements within the technology, policy and consumer dimensions, because the details really matter. For example, in addition to modeling carbon pricing, we can model other carbon policy structures, for example, a ban on or restrictions on Lower 48 unconventional reservoir fluid development. Now depending on the case, because higher cost of supply resources would be needed to replace U.S. oil and gas, this could result in increases to the cost of supply that range from $10 to over $30 or $40 a barrel. Now beyond the negative implications this would have for the U.S. and the world economy, it would actually be counterproductive from an emissions perspective because unconventional resources are not only low cost of supply, but also low carbon intensity too. So this sort of granularity is important and is part of our scenario modeling capability.

And our Scenario Monitoring System gives us the ability to recalibrate and update the priorities and probabilities as we go through time. So these scenarios represent a wide range of future worlds that we could be operating in. So what do we do with them? Well, the range of potential future outcomes drives our strategic choices. And thankfully, the answers to the fundamental strategic questions are consistent across all the scenarios. First, how should we manage uncertainty? Well, across all the scenarios, these answers work: Maintain a strong balance sheet and a low breakeven price, retain exposure to upside in price and proactively manage climate change risk. Second, what portfolio should we choose? Again, there are several no-regret answers here. Have and maintain a diverse portfolio that is low cost of supply, low base decline and low capital intensity. And then finally, how should we allocate capital? We must optimize the pace of our capital investments, consistently execute our programs through the cycles and focus mercilessly on returns and generating free cash flow. And you'll see that our strategy is designed to address all of these realities.

Okay. So I've just spent some time providing you some context on how we run our business and how we think about the choices to address the strategy paradox. So let's get into some of the meat now, starting with our portfolio. We've used the phrase cost of supply about half-a-dozen times now for those of you who have been keeping track or not been keeping track. Because the fundamental tenant that we follow is that in any future world, low cost of supply wins. So when we say cost of supply, what do we actually mean? It means the WTI price required to get a 10% return after tax on a going-forward basis, and this is an illustrative example of what it includes. Firstly, on the left, facilities and wells capital. This is not capital cost per barrel, this is capital cost per discounted barrel. And that's important because the capital usually comes up-front and the production comes later. In fact, all of these measures on the slide here are discounted measures but the one that has the most significant impact, a discounting impact, is on capital.

Secondly, we add all the elements of operating costs, lifting cost, transportation to the hub and overhead costs, both direct and allocated. In other words, fully loaded OpEx.

The next two elements deal with the fiscal regime. Now obviously, the characteristics of fiscal take vary across the world, but we are predominantly in tax and royalty regimes so that's what we've illustrated here. Then we've got to make an important adjustment for the fact that we're typically not producing 100% oil, and that adjustment is made not based on the heating-value parity, but on monetary value parity in the relevant market. So for example, the price of gas in North America is converted to oil at a ratio of about 20:1 to reflect the value advantage that oil has over gas in the North American market.

Then finally, we adjust for the marker differential to WTI. In the case of Western Canada crude, that would increase the cost of supply on a WTI basis. For Alaska oil, that would decrease the cost of supply on a WTI basis. We do this across 100 entities -- more than 100 entities across the portfolio and they all have to have a cost of supply below $40 a barrel after tax to make it into our development plan. This approach that's reviewed and blessed by our corporate experts means that we have a consistent framework across the whole company that allows us to focus on the areas that we can tackle to continue to reduce cost of supply. It's independent of prevailing oil price and is the primary decision criterion in the company.

So let's move on and look at the cost of supply distribution across the portfolio. But first, a quick piece of housekeeping to describe how the resource base has changed since we last published a supply curve, in 2018. Around this time last year, we had 16 billion barrels of resource below $40 a barrel. Over the last year, we've closed the sale of our U.K. business and announced the pending sale of our Australia-West assets. And of course, we produced some of the resource. That would leave us with 15 billion barrels of resource. In this plan, we're assuming one further significant portfolio change that will dilute our operated Alaska position in Kuparuk and Western North Slope from around 100% equity to around 75% equity. Now we've increased our position in these assets over the last couple of years at very favorable acquisition prices that allowed us to get control of the investment pace and fully capture the value from our exploration success and the Nuna acquisition. But we don't intend to proceed with the long-term development of these assets at 100% equity. That would be inconsistent with our practice of managing large-scale projects. So we've adjusted the resource base down to reflect that this dilution is in our plan. We've also added resource through the year, from a mixture of cost of supply improvements, exploration and acquisitions. This leads us to a total resource base at the end of 2019, including the impact of the future Alaska dilution, of 15 billion barrels, and we've increased the percentage of that that's below $30 a barrel in the process. Our current production rate, that's a resource-to-production ratio of over 30 years. So what's the resource comprised of? First point I want to make clear is that the 15 billion barrels is only 40% of our total resource base of 37 billion barrels. And as I'll describe shortly, we have a great track record of converting resource from above $40 to below $40 a barrel. The reason we highlight the 15 billion barrels is because that's the resource that attracts capital in the plan. In fact, the resource we plan to develop has an average cost of supply below $30 a barrel. And you can see that it's diversified across these four megatrends. Just over half the resource is in unconventional assets in the Big 3 in Montney, about one-third is in our conventional assets, and the remainder is fairly evenly split between oil sands and LNG. And just a quick editorial point here. We've been disclosing our supply curve to the market for four years now, and we're still the only oil and gas company that does so. We think that is a great example of the transparency in our disclosures that Ryan referenced earlier. And the resources are not just diversified geologically, they are diversified geographically as shown in this chart. About 45% of the resource is in the Lower 48, 20% in Canada, 15% in Alaska and the remaining 20% is spread across APME and Europe. So that's the current resource base, 37 billion barrels of oil equivalent, which we develop 15 billion barrels of because it has the lowest cost of supply. Of course, we run a business where we deplete our resource base every year. So in the context of a 10-year plan, we thought it would be appropriate to explain how we think about adding resources to the plan over time. There are really only three ways to add resource: Access more from within our existing portfolio, find more through exploration or add new resources inorganically. As you'd expect, we come at all three of these with consistent decision criteria to ensure that the new resource will be competitive within our existing portfolio. The primary decision criteria we use are that the development of the resource needs to be less than $40 a barrel cost of supply, and the all-in life cycle cost needs to be less than $50 a barrel.

Let me explain why we think of it that way. Before we bring an existing resource into the development plan, there are typically technology development, engineering and pilot testing costs. We think of these as the cost to convert the resource from above $40 to below $40 a barrel. We call this the "conversion cost." In the case of exploration, the equivalent would be the all-in exploration and appraisal costs. And in the case of inorganic resource, it would typically be the acquisition cost. Now in the industry, these are generally referred to on a cost-per-BOE basis. That's what's shown in the first waterfall bar that I'm going to build up here in a moment. To transform the center cost of supply equivalent, we need to follow a process consistent with the technique I showed a few slides ago when I described our development cost of supply. So we adjust for all the factors required to get those barrels into a WTI-equivalent basis, like mix and differentials. We then adjust for the time value of money because, again, these costs are incurred before production. And when we aggregate these, this gives us the conversion finding, or acquisition costs on a pre-development WTI cost-of-supply basis. To that, we add the go-forward development cost of supply, which needs to meet the less than $40 a barrel threshold, and the aggregate of these components needs to be less than $50. We also want resource additions to be accretive to our value proposition, consistent with our financial framework and provide an opportunity for us to bring our technical and expertise to bear to add value. Now this provides a consistent framework for all three sources of future resource additions: Resource conversion, exploration or inorganic additions. And we have a strong track record in each of these categories, as I'll explain now, starting with replenishing the resource base from within our existing portfolio.

When we launched our value proposition in 2016, we had 10 billion barrels with a cost of supply below $40 a barrel WTI. Since then, we have added 5 billion barrels below $40 a barrel. 2 billion has come from the Big 3 as we've driven down capital and operating costs, increased the number of development wells and improved recovery per well. 1 billion has come from resource additions in APME; for example, cost of supply reductions in China and Malaysia. And 2 billion barrels has come from ACE from seismic advances in Ekofisk, longer laterals in Alaska and improvements in Surmont's cost of supply. We added these resources from within the portfolio at very low cost through technology development, pilot testing and creative engineering solutions. We also added resource from exploration during this period. Our exploration strategy within our existing regions is focused on business units where we see potential for meaningful resource adds. You're going to hear about each of those from the regional presidents shortly. Our new ventures activity is currently focused in Argentina and Colombia, and we've had a lot of success in the exploration channel over the last 3 years. We've added 2 billion barrels of resource, dominated over this period by Alaska and Montney, all with development costs below $40 a barrel. And we intend to continue this strategy with an annual capital spend of $300 million in the base plan directed towards testing new prospects in place. And we've also been active in acquisitions. Our inorganic additions have all been asset purchases or trades. Or just over the last few years, they've all been focused in North America. Since 2016, for a capital cost of less than $1 billion, we've added 1 billion barrels, with the development cost below $40 a barrel in the Western North Slope, Kuparuk, Montney, the Permian and the Eagle Ford. These are great pieces of business and we will continue to pursue them.

Now obviously, they're difficult to forecast. So they're not reflected -- any new inorganic additions are not reflected in the base plan.

Now time for another editorial, this time to address the elephant in the room. We know there's a lot of speculation about whether we're going to do a major acquisition, so we want to address that directly. Now obviously, we can't, and we shouldn't rule that out, but we can rule out doing a bad acquisition driven by the wrong reasons. Today's in-depth review of the portfolio and 10-year plan will clearly demonstrate that we don't have a problem in this portfolio that needs fixing. You've also seen us aggressively reshape the portfolio mostly through dispositions, so it should also be clear that we are not driven by a desire to get bigger. And after doing all the work to get our balance sheet in shape, we're not going to do something that undermines our financial framework. We are thoughtful, patient and value-oriented, and we can assure you that any acquisition will be premised on maintaining balance sheet strength, meeting our commitment to distribute at least 30% of cash from operations to shareholders and adding low cost of supply on an all-in price of less than $50 a barrel. Now we considered calling the Houston Zoo to see if we could have an actual elephant in the room, but we thought addressing this head-on will be less messy for all of you. Okay, so that's the editorial over.

Let me summarize how we've replenished low cost of supply resource in 2016. We've added 5 billion barrels by converting resources within the portfolio to less than $40 a barrel. We've added 2 billion from exploration, 1 billion from acquisitions. Now over that period, we've sold some assets, and we've produced some oil and gas. But the net effect is at the end of 2016. Since the end of 2016, we've grown our less-than-$40-a-barrel resource base from 10 billion to 15 billion barrels. So that's the first element of the right portfolio. It needs to be low cost of supply, and resource adds need to be low cost of supply too.

The next key portfolio attribute is low capital intensity, and that's driven by the base decline rate. We have a differentially low base decline rate and we sustain it through the decade. Let me explain why that's the case. We consider the base decline rate, that's the rate at which all the wells we have on at the end of any given year decline in production from there-on-out. So if we take all the wells that we'll have on at the end of this year and just play them out through 2020 and beyond, base production will decline about 10% a year. We then add new wells in 2020. This new production results in an instantaneous decline rate in the first year of 20%. And as you can see on the bottom left here, that's one of the lowest first-year declines in this group of 39 U.S. independents. This is because the new production we are adding isn't all high-decline unconventionals. And by the way, the couple of bars to the left of us on this chart are smaller companies that don't have any unconventional assets. Now by the end of 2020, if we just produced-out all of the wells now online, our base decline would be 10% a year. The same applies to next year and the next year and all through the decade as illustrated here for three discrete periods. So how are we able to sustain such a low base-decline rate compared to our peers? Well, for several reasons. Firstly, our underlying base is supported over the decade by net-zero-decline assets in oil sands and LNG and very low-decline assets at Prudhoe Bay and Kuparuk, for example. Secondly, as I explained earlier, the decline rate of our new production is lower than most of our competitors because it comes from diverse sources. And thirdly, although we are growing, we are not growing at such a pace that the base can't keep up. As I'll show you in a minute in our optimized plan, we're growing an average of around 3% a year over the next decade. But why does this base decline really matter? Well, because low base decline results in low capital intensity and high free cash flow. This third-party data for 2019 shows that this combination places us first among our peers in free cash flow generation by quite a long way and that's by design because of the portfolio choices we've made. Several of our peers, and particularly pure-plays, struggle to reproduce this because they don't have a balanced portfolio. Now there's a lot more I could say about why our low cost of supply, low-decline portfolio is the right one for our industry, but you're going to get a much deeper dive into each of the elements of the portfolio from the regional presidents in a few minutes so I'll move on.

I'm now going to cover how we think about the optimized pace of development within our assets, how that results in capital phasing across the assets and how that leads to significant free cash flow growth over the decade. When we are determining the optimal development pace for our assets, we're trying to answer one long crucial question: What investment pace optimizes value and capital efficiency and leads to high returns through the cycles? This question applies equally to our conventional or unconventional assets. I'm going to use a generic example to explain how we think about this. We start with a view of plateau rate on the x-axis versus NPV on the left axis. Across the reasonable price range, the shape of this curve is pretty similar, pretty independent of price, so we've normalized 100% of the maximum NPV on the y-axis. For unconventional reservoirs, you can also think of the x-axis as a steady-state rig piece. So the answer is obvious: Build to the plateau rate that maximizes NPV, right? Well, not from our perspective because that ignores capital efficiency. If we are adding $1 billion of capital to get $1 of NPV has got to be uses of that capital. So we add a secondary axis to deal with this capital efficiency issue. The metric we choose to use is incremental cost of supply. We could use other metrics like incremental profitability index, but -- and some of the most perceptive of you may have picked this up -- we're a wee bit obsessed with cost of supply, so that's what we use.

Now typically, the incremental cost of supply curve has a shape like this, increasing from left to right. In practice, especially for conventional projects, it can be more discontinuous, more stair-stepping than this, but always has this underlying characteristic, because more throughput capacity requires more infrastructure. We then apply a threshold of $40 a barrel cost of supply. It's important to note that this is the incremental cost of supply. The average would be below $40 a barrel. This leads to a capital efficiency-constrained plateau rate. But in all cases we've looked at across the portfolio, every one, it captures more than 95% of the NPV. This results in resilient investments that will deliver returns above our capital throughout the cycle all the way down to $40 a barrel. But this isn't the only benefit of this approach in a cyclic environment. Let's consider a world where we have price cycles like this with a 3-year wavelength around some mid-cycle price. And put it in the context of unconventional reservoir development. The way most of the industry thinks about capital discipline now is simply "live within your cash flow and leave a bit over to distribute to shareholders." Taken that literally, we'd have you running more rigs and higher prices and fewer rigs and lower prices. There's already an obvious problem here. You invest in more capital in periods of high inflation and less capital in periods of deflation. But it's worse than that if you consider the incremental production associated with this approach compared to a steady-state approach, because the lag between drilling and producing the wells means you end up producing more oil in the low-price environments and less oil in the high-price environments. This is not good.

Unfortunately, we know this because we did it. Earlier, I mentioned we had learned something really important from our look-back process. Well, we looked back at what we did in Eagle Ford and Bakken from 2014 to 2017. We rejacked our rigs up and down to get through the cycle because we were managing the cycle using capital flexibility. Our look-back analysis showed us that had we run steady-state instead through the cycle, our economic rate of return would have been at least 5 percentage points higher. Now if you apply that return delta to a large-scale capital program like ours over a decade, that's a lot of value our shareholders would be missing out on. But wait, there's even more advantages to this approach. By not jacking our activity around or not confusing our workforce or carrying too high a G&A burden, we can continuously and consistently deliver our learning curve. And it helps with our supply chain strategy with our contractor relationships. And really importantly it improves our safety performance, because we get to work consistently with the best crews in the industry. That's why our definition of capital discipline now is optimized, consistent through cycle execution of the capital program. In other words, have a strong balance sheet, including cash, and exercise balance sheet flexibility through the cycles, not capital flexibility. Exactly the same philosophy applies to our approach to dollar-cost averaging our buyback program, as Don will describe later.

So I've just laid out a dozen reasons why this approach to capital discipline makes sense. Go back and count them in the transcript, so a dozen reasons. So now what I would like to do is to show what this optimized approach results in for our unconventional and conventional programs, starting with our unconventional portfolio.

Now Dominic and Michael will cover these assets in a lot more detail shortly, but in summary, we've applied our optimized plateau and consistent rig-loading philosophy to our Big 3 assets and Montney. As a result, our plan is that we will stabilize activity across the four assets around 20 rigs, and the unconventionals will attract just over $4 billion a year on average through the decade. We expect this to result in production growth from 400,000 barrels a day to 900,000 barrels a day over these 10 years, and there's remaining growth to come yet as Montney heads towards plateau in the early 2030s. The same optimized-pace model has been applied to the conventional assets. This results in planned average capital of about $2.5 billion between the base development drilling and future projects. That will stabilize production between 750,000 and 800,000 barrels a day from a conventional business. Bill and Michael will get into the details of specifically where do we plan to allocate this capital.

So all the points I've made so far illustrate the fundamentals that drive the 10-year plan. So let me walk you through the plan now. I'm going to build this up like a sedimentary rock, layer by layer. First, we expect LNG and oil sands to contribute a steady 250,000 barrels a day through the decade for almost none of the plan's capital. We expect the conventional base to take about $300 million of maintenance capital annually and decline about 10% a year. When we add the unconventional base, we get to a total base production of just under 1.1 million barrels a day in 2020 and the aggregate decline of this base is 10% a year, as I discussed earlier. Now we inject in the conventional growth an average capital of $1.7 billion a year, and this results in a stable conventional production at the top of the green wedge between 750,000 and 800,000 barrels a day. Then the unconventional growth kicks in. The aggregate effect is a compound annual production growth rate of about 3%. And then finally, we add in our exploration capital of $300 million a year, and that gets us to a total average capital of just under $7 billion.

Now obviously, we're not assuming any production associated with resource we haven't discovered yet. Now I'm going to quickly describe the same plan and the time dimension to give you another way to think about this. In the first third of the plan, capital average is $6.5 billion as we add a few rigs to the Permian and invest in the Willow prospect. Over this period, we expect production to grow about 4% annually. In the middle of the plan, the capital average is $7.4 billion as we complete the Willow infrastructure and continue to add rigs in the Permian and Montney to get them towards their optimum plateau. Production growth over this period is also estimated to be about 4%.

In the last third of the decade, Willow infrastructure was commissioned, when we moved into the sustainable drilling phase and the ramp to three rigs in the Montney is complete. Over this period, we plan for capital to average a bit less than $7 billion and the rate of growth to slow to about 2%. Now another quick piece of housekeeping before I leave this slide. The plan you'll see today and what's shown on this slide reflects the underlying capital in production to account for the dispositions we've announced and the 25% dilution of the Alaska-operated assets. For the simplicity, these charts assume that all happens at the start of 2020. But in reality, we may not complete the Alaska sale in 2020 and the other dispositions might not close until the end of the first quarter. So our preliminary 2020 capital and production guidance will be a little bit higher than what's shown on these graphs and the difference is shown very clearly in the 2020 guidance we provided in the appendix.

Okay. So that's a high-level look at capital and production in the plan. But what you really want to know is, well, what does this deliver? Well, it delivers a lot of free cash flow. I'm going to build the free cash flow up on a geographic basis, then hand over to Bill, Michael and Dominic, to get into the details of how and why this shows up in each of their regions. All the free cash flow projections are done at $50 a barrel real WTI.

First, we expect the Asia-Pacific and Middle East region to steadily deliver $15 billion of free cash flow through the decade. In fact, in the first third of the decade, APME delivers half of the company's free cash flow for just 5% of the plan's capital. The Lower 48 is self-funding throughout the plan. We forecast free cash flow to grow from about $1 billion a year in 2020 to over $2 billion a year in the first five years and then stabilize through the end of the decade. On this basis, over the 10-year plan, Lower 48 delivers about $19 billion of free cash flow. Finally, in the plan, Alaska, Canada and Europe region, free cash flow growth is back-end loaded because of investment in Willow and Montney. We expect each to contribute a total of 16 billion barrels and to be delivering $3 billion a year of free cash flow by the end of the decade. That results in the total free cash flow of $50 billion that Ryan mentioned right at the start of the presentation.

So what have we covered in the last 40 minutes or so? Well, we've discussed how we resolve the strategy paradox, the paradox of needing to commit to a strategy in the face of profound uncertainty by answering three fundamental questions: How should we manage this uncertainty? What portfolio should we choose to have? And how should we allocate capital? And we've given you a comprehensive answer to all three of those questions. Let me describe how our portfolio has 15 billion barrels of low cost of supply resource and how our decline rates result in differential free cash flow generation. And we've laid out a rational construct for the pace of capital allocation, leading to an optimized 10-year plan. We hope you agree that this is a cogent, coherent strategy that's specifically designed to deliver superior returns through the cycles.

Okay. Now I'm going to hand over to the regional presidents to put some more flesh on the bones here, starting with APME that Bill will take you through. Bill?

Bill Bullock ***ConocoPhillips Company - President of Asia Pacific & Middle East***

Thanks, Matt, and good morning. I'm looking forward to discussing our Asia Pacific and Middle East region with you in detail this morning, so let's dive right in. As Matt has just shown, the region is a low-capital-intensity, free-cash-flow machine, which we expect will provide $15 billion of cash flow over the planned period in a fairly ratable fashion. And importantly, under our plan, over 50% of ConocoPhillips' free cash flow will come from this region over the next three years. After our recently announced sale of our Australia-West business, we're producing in five countries. We have LNG operations in Qatar and on the East Coast of Australia, and these equity affiliates provide steady production and reliable cash generation. The Corridor Block in Indonesia is a significant gas producer. In China, we have multiple phases of ongoing development in the Bohai Bay Field, and in Malaysia, we have a solid stream of attractive future phases of investments and a focus on growing through exploration. The region contains about 2 billion barrels of resource or about 15% of the company's resources under $40 a barrel, with an average cost of supply of less than $20 a barrel. This is some of the lowest cost of supply resource in the portfolio. 70% of the resource base is in LNG-producing assets, both Qatargas 3 and APLNG. These are the orange bricks on the chart. The remainder is in conventional assets, including the Corridor PSC in Indonesia and multiple phases of development in China and Malaysia. I'll provide more insight into each of these businesses in just a moment. We expect capital investment in the region to average about $300 million per year, or less than 5% of the company's capital over the planned period, and all of this is while delivering 20% of the company's production, averaging around 300,000 barrels a day. And importantly, it's high-margin, with over 90% of our sales volume in the region indexed to oil, whether through actual oil production, oil-linked LNG contracts or oil-linked gas contracts in Malaysia and Indonesia.

The combination of high margins, low CapEx and stable production provides the platform for strong free cash flow generation. That's how APME delivers 30% of the company's free cash flow over the next 10 years. So let me show you the details.

I'm going to begin in Qatar, where we have a 30% investment in Qatargas 3. Now Qatargas 3 is a fantastic asset. It's a 7.8-million-ton-per-annum LNG facility producing from the North Field, the largest contiguous conventional gas field in the world. We expect that it will produce over 80,000 barrels a day throughout the planned period, all while requiring negligible additional capital. And we're pleased to have been invited to submit a bid proposal for participation in the North Field Expansion. Only a few companies have been invited to do that.

Next, I'd like to discuss APLNG, our LNG asset in Queensland, Australia. Like Qatargas 3, APLNG also provides strong production and reliable cash generation. We expect APLNG to provide about $500 million per year in net distributions to ConocoPhillips, with distributions increasing by $20 million per year for every $1 a barrel increase above $50 a barrel WTI. The venture has a very low distribution breakeven price of less than $35 a barrel, including all underlying capital and project finance obligations. The LNG facility itself is operating very, very well. We're routinely achieving over 99% reliability and can produce at 110% of nameplate capacity. And we have a laser focus on reliability, particularly on turbines as they're the heart of LNG plant operations. In fact, we've reduced trips on main turbine packages by almost 90% since our first full year of operation in 2016 and this is through predictive maintenance and rigorous defect elimination efforts. Over the planned period, we expect APLNG to produce over 100,000 barrels per day net to ConocoPhillips. About 20% of this production is sold into firm domestic contracts. That's the dark wedge at the bottom of the chart, and it's worth noting that APLNG supplies about 30% of the East Coast of Australia's gas market. About 70% is sold under two 20-year LNG sales agreements into China and Japan, and the remainder is currently available for sale into the spot market, and that's either domestically or as spot LNG.

Finally, I'd like to draw your attention to the yellow acreage showing APLNG's position in Queensland. We have a very large acreage position. It's about 4.6 million gross acres, and we're differentially positioned in some of the most productive portions of the Surat Basin. We have got line of sight to low cost of supply resource development programs that will enable us to fulfill our contracts and to capture additional market opportunities as they emerge.

Now before I move to our next asset, I do want to pause just briefly and remind you that we have a "business inside our LNG business," and that's licensing our Optimized Cascade liquefaction technology. We license this technology globally, and over the past 20 years have grown the business to become the second-largest liquefaction licensor in the world. But that really doesn't tell the full story. Since 2015, projects using Optimized Cascade represent about 50% of global new-build capacity. The business has been a significant cash contributor to the corporate segment, contributing over $1 billion in cash. Now we collect this revenue as new LNG trains are commissioned, so it's a lumpy income stream, but it is very good value.

Okay. I'd like to return back to our asset reviews. And next, I'll talk about Indonesia, where we've had an operating presence for 45 years. ConocoPhillips operates the Corridor Block in Indonesia, providing natural gas to Jakarta, the Duri steamfloods, other domestic customers and customers in Singapore. The asset currently produces about 55,000 barrels a day, and we've just signed a new PSC, granting us the opportunity to continue in the corridor block for another 20 years. This is after our current PSC expires December 2023. We have a very strong track record in Indonesia, including superb project management. Our last two major projects, the Sumpal Compression and Suban Compression projects, were executed 30% under budget and with an average cost of supply of less than $10 a barrel. And importantly, the business has one of our leading safety performances in the company.

Next up is China, where we have a great legacy position in Bohai Bay. We're currently producing about 30,000 barrels a day from multiple developments in Bohai Bay, as shown on this map, and it's all oil production. It has some of the highest cash margin in the company at approximately $35 a barrel. Phase 3, shown as the orange wedge on the graph, had 2 wellhead platforms come online in the fall of last year, and we'll continue to ramp up, with wellhead platform K expected to come online mid-2020.

You can also see that we have additional low cost of supply wedges planned, which extend the production plateau of Bohai Bay and offset the underlying base annual decline rate of about 15%. I'd like to highlight these for you on the next panel.

One of the ways that we have lowered cost of supply in China is by standardizing kit for our development projects. We've collaborated very closely with our operator CNOOC, who's done an excellent job in repeatable, reliable execution. There's multiple aspects to this improvement. For instance, optimizing and standardizing platform designs, increasing the use of local content and construction-peer reviews, and these efforts have resulted in significant platform weight reductions, scheduled improvements and notable cost savings. The future development phases really do match what the pictures on this timeline imply: The platforms are essentially cookie cutters. They're being built in the same yards and by the same project teams. The capital cost reductions for Platform J in Phase 3, shown on the bottom left, will roll forward in the Phase 4A and 4B. And not only does the capital costs improve with repetition, we are seeing reduced cycle times from FID to first oil by up to 6 months. So we're getting production more quickly and for less money, which all leads to an attractive portfolio of future development phases and the cost of supply of less than $30 a barrel.

Malaysia is up next, and the story is much like China. It's a great legacy asset with multiple phases of development, but with an added exploration focus. We're currently producing offshore from Malikai and SNP, Gumusut and the KBB cluster, and production is currently around 60,000 barrels a day. It has strong cash margins, and we have several low cost of supply Phase 2 and Phase 3 projects, which I'll discuss in just a moment.

Our focus in Malaysia is to build upon the solid foundation we've established and find new opportunities for future growth. We've been picking up prospective acreage on the shallow-water shelf and have recently begun a multiple-well exploration campaign on the acreage shown on this slide. Now to give you a sense of scale, the two exploration areas shown on the map are about 1 million acres each. That's equivalent to about 340 Gulf of Mexico blocks, so there's lots of room for prospects.

But back to our developments in Malaysia. We have Phase 2 and Phase 3 drilling programs for Gumusut, Malikai, SNP and KBB. All the future phases have very low-cost supply and attractive returns, just as you would expect from projects where the core infrastructure is already installed.

For example, Gumusut Phase 2 came online in August and has a cost of supply of about $7 a barrel. Malikai Phase 2 is approaching FID and also has very attractive metrics. And in fact, the entire program averages less than $15 a barrel cost of supply. I'd also like to note that the PETRONAS floating LNG facility came online in May. The floating LNG facility supplements offtake at KBB, adding about 7,000 barrels per day to our KBB production.

Okay. Going to exploration just briefly. We've used our proprietary 3D compressive seismic imaging over all of our blocks in Malaysia to help enhance our prospect identification. The image quality is significantly enhanced compared to conventional seismic and it's acquired at lower cost. Now this is a 2D CSI slice, but of course, the geologic faults are occurring in three dimensions and understanding them is critical for our identification of prospects. It takes a significant amount of time to interpret those faults manually, particularly on blocks as large as the ones in Malaysia. So we've recently been trialing using advanced analytics and machine learning to identify these faults, and that's what's shown on the right. This method has proven to be incredibly accurate, reducing our interpretation time by a factor of 10. We're already looking at additional opportunities to apply machine learning to the interpretation of reservoir signatures. And as we do this, this frees our geoscience staff from the more-tedious activities and allows them to spend more of their time on prospect identification and can dramatically accelerate the exploration timeline. So needless to say, we're really excited about this innovation.

So that wraps up my asset-by-asset review, but I do want to just briefly discuss how the region addresses environmental and social issues. You'll hear about this from each of the regional presidents, as that's core of every part of ConocoPhillips.

We have strong programs across the region. I'm just going to highlight two. Our APLNG facilities are located on Curtis Island. It's within the Great Barrier Reef World Heritage Area. We have gone to significant effort to ensure that this site is managed in an environmentally responsible manner. For instance, we have an ongoing active marine turtle management plan at APLNG, including a 10-year monitoring program that helps identify changes to turtle populations. And so far, the research shows that Curtis Island LNG facilities have no impact on marine turtles or their habitat. And in Indonesia, our business has been recognized with six corporate social responsibility awards in just the last two years. That's from three ministries, three regional authorities, and all for our efforts in helping local families becoming more independent and more self-sufficient.

Our workforce across the region is dedicated to long-term success through a focus on sustainability.

So let me take you back to where we started. The key takeaway is the region as a low-capital-intensity, free-cash-flow machine. Our LNG projects at APLNG and Qatar provide significant reliable distributions throughout the plan. Our conventional assets in China, Malaysia and Indonesia have excellent cash margins and a solid inventory of low cost of supply future phases development. And of course, we're always looking for opportunities to extend our success in the region. So that's how, over the next 10 years, we're going to deliver $15 billion of free cash flow at a $50 barrel price.

So thank you. Now I'd like to hand over to Michael, who will tell you about our high-value investment opportunities in the ACE region. Michael?

Michael Hatfield ***ConocoPhillips Company - President of Alaska, Canada & Europe***

Good morning. Thank you, Bill. I'm excited to talk with you about our ACE region. You can think about ACE as a microcosm of ConocoPhillips, where we'll make high-value investments that generate a lot of cash in the 10-year plan and beyond. This slide shows how ACE fits into the company. Let's look briefly at each of these areas before we get into the details. In Alaska, Matt mentioned the 25% sell-down of our operated assets. With this sell down, we'll be producing over 180,000 barrels a day and have significant running room with these conventional assets. In Canada, our Montney unconventional asset has a resource base of 2 billion barrels and Surmont is a large oil sands asset, where we're making significant improvements to reduce the cost of supply 35%. In Norway, we produce 130,000 barrels a day from these legacy conventional assets. Now in the next decade, we expect our ACE assets to generate $16 billion of free cash flow. This represents over 30% of ConocoPhillips' total free cash flow. So let's look at the resource base that's generating this cash.

ACE has 6.4 billion barrels of resource, which is 40% of ConocoPhillips' resources. These assets have an average cost of supply less than $30 a barrel. In rough numbers, Alaska has 2.5 billion barrels, Montney has about 2 billion, Surmont has 1 billion and Norway has about 700 million barrels. Now let's look at the capital to develop these resources and the production we'll generate as we execute our 10-year plan.

Over the decade, ACE will attract about 40% of ConocoPhillips' capital and deliver one-third of our production. Capital averages about $2.5 billion a year. We expect this investment will generate production growth of 5% per year, with the region growing from 400,000 barrels a day in 2020 to exit the decade at around 600,000 barrels a day. Our largest investments are in Alaska with $15 billion, which will generate strong production and cash flow growth. We'll invest nearly $7 billion in Canada over the next 10 years and expect to grow production in Montney throughout the decade and beyond to over 250,000 barrels a day. Our Surmont oil sands production grows from 65,000 to 85,000 barrels a day, with modest sustaining capital and some debottlenecking activities. Our production in Norway declines modestly to exit the decade at about 90,000 barrels a day.

Now let's take a deeper look at these assets. Let's start with Alaska, where we've operated there for over 40 years. For those who aren't familiar, our primary assets are from east to west, our nonoperated interest in Prudhoe Bay and our operated assets are Kuparuk in the center and the Western North Slope. We have established infrastructure in these areas and exploration opportunities in the west, where we have our Willow and Narwhal discoveries. The timeline at the bottom notes a few milestones, including how we intend to grow these legacy assets with development drilling from existing facilities, small projects within our core fields, large new projects and exploration upside. We'll touch on each of these activities in the coming slides.

Let's start with our base production. Over the last few years, we've reduced our base decline rate from 8% to 6%. The thumbnails at the bottom show a few of the ways we're mitigating our decline. On the left, we're improving our waterflood management and enhanced oil recovery performance by optimizing the allocation of our water and miscible gas injection. This improves the waterflood patterns and results in recovery in those areas up to 60%. The middle thumbnail is an example of how we're using data analytics to quickly identify opportunities where we can optimize our gas lift operations. This helps mitigate our base decline.

Lastly, by optimizing our maintenance activities, we've improved our uptime 4%. Going forward, we're using predictive analytics and artificial intelligence to minimize downtime on critical equipment. This drives further improvements in facility uptime. And we have a lot of growth opportunities to layer on top of this strong base.

Over the last 40 years in Kuparuk and Alpine, we've brought online 54 operated drill sites. We've added four new drill sites in the last five years. These include CD5 in Alpine and our initial development of the Northeast West Sak area in Kuparuk. We've invested over $2 billion gross in these four projects and have a cost of supply of around $30 a barrel. These projects were delivered 7% under budget, with 5% more resource than expected and represent 35% of our current operated production. Now as we continue to leverage these areas around our core assets, where we have several projects teed up in the next five years, which you can see on the right. The most significant is GMT2. It was sanctioned last year and has first oil in 2021. It will cost $1.4 billion, have 48 wells and be produced into our existing Alpine facilities. This development extends our infrastructure to the west and has a cost of supply of $18 a barrel. We'll also develop the Nuna resource, which we acquired earlier this year. This is a new addition to what we showed last year at the Alaska Investor Tour. And it comes online quickly, we'll have first oil in 2022, with a tieback that leverages our existing Kuparuk facilities. The Eastern NEWS area is a continuation of our successful West Sak development. We plan to develop this area with 20 to 25 wells from new Kuparuk drill sites. All of these wells will be multilateral horizontals.

At Narwhal, production is slated to start in 2022 to our Alpine facilities and continues relatively flat for many years. I'll discuss the details of Narwhal later.

We also have several incremental projects at Prudhoe Bay, which will be executed in the near future. So in aggregate, these new projects have a cost of supply less than $25 a barrel. By the middle of the next decade, we expect these projects to have peak oil production of over 50,000 barrels a day.

Now let's look a little deeper at our drilling, which is one of the key enablers of this performance. We have an exceptional track record in Alaska of drilling challenging wells to deliver resources that would be inaccessible by traditional methods. At CD5 in the Western North Slope, we've drilled the 10 longest wells in Alaska. You can see several of the records on this graph. The longest well is over 32,000 feet. The longest lateral ever drilled in North America, at nearly 22,000 feet. And we were able to reach our Narwhal appraisal target from an existing pad at a relatively shallow depth of a high sail-angle of 83 degrees and a horizontal distance of over 3 miles. And we expect to push the records even further because next year, we'll take delivery of a newbuild extended reach drilling rig.

This ERD rig is the largest mobile land rig in North America. It has the latest in drilling technologies, including managed pressure drilling and the latest in rig automation. It incorporates a reflexive drilling system that can automate repetitive tasks and improve performance significantly. These technologies will enable us to manage the challenges of drilling even longer and more complex wells to access additional resources. This rig is capable of drilling more than 7 miles away from the pad. Compared to existing rigs, it has 3 times the subsurface coverage. To put this in perspective, with the ERD rig centered in Lower Manhattan, we can reach the other four boroughs covering an area greater than 150 square miles. Having a reach like this allows us to maximize resource recovery, while minimizing the surface footprint.

Over the decade, we expect the ERD rig will access 100 million barrels at a cost of supply of $25 a barrel. Our track record of execution has allowed us to economically develop these areas and will be key to continuing to unlock value in Alaska. So that was a high-level look at our prospect-in-development drilling programs across and adjacent to our existing fields.

Now let's take a look at our exploration and appraisal program, starting with our 2019 campaign at Narwhal.

We discovered the Narwhal accumulation in the 2018 winter drilling season with two exploration wells and an appraisal sidetrack drilled from ice pads. This year we drilled an extended-reach horizontal well to Narwhal, which is shown in red, from our existing CD4 pad. You can see at the bottom right graphic on the geosphere image, we encountered a consistent, thick oil-bearing sand along the full length of the horizontal lateral. The well test established high productivity, with a peak rate of over 4,500 barrels a day. As a result of these encouraging wells to date, we're increasing the Narwhal resource range to 150 to 400 million barrels. That's a 50-million-barrel increase compared to the midpoint of our previous range. So we've been very encouraged by the results of this year's appraisal at Narwhal.

Now let's take a look at what we've learned at Willow. In the last winter drilling season at Willow, we completed two horizontal and four vertical appraisal wells to further delineate the reservoir and increase our confidence and our resource estimate. The two horizontal wells averaged over 2,500 barrels a day. This exceeded our expectations.

Because of the limited drilling season with -- and the limits on the test equipment -- these wells only had 2,000-foot laterals. This is only about 20% of the lateral length of the future development wells. In a full development scenario, the longer laterals will clearly translate into higher rates.

We also conducted two interference tests from the new vertical wells, which are 1,800 feet away from wells that were previously drilled. This involved injecting water in the new wells and monitoring the pressure responses in the existing wells. We chose 1,800 feet because that's the well spacing in development and we went in to test transmissibility across that distance. The results of this test program can be seen on this graph. The dynamic production and injection tests achieved an excellent response. These interference tests have clearly demonstrated that water flooding will economically increase recovery.

So at Willow, we've established high productivity and good inter-well connectivity. This information will inform our well spacing and facility sizing. As a result of these tests, we're increasing the EUR at Willow to 450 million to 800 million barrels. That's a 50-million-barrel increase from the midpoint. We have one more winter drilling season ahead to finalize appraisal at Willow and Narwhal, so let's look at those plans.

At Narwhal, we're currently drilling an injection well, which is the easternmost dot on this map. It's 1,800 feet away from the production well we just tested from the same Alpine pad. Later this year, we expect to complete this injection well to test reservoir connectivity, much like the interference test that we ran at Willow.

We're also in the midst of planning our upcoming winter drilling program further west. This program will consist of four appraisal wells at Willow and three exploration wells at Harpoon, which is a large new prospect. It's the large orange area, 25 miles southwest of Willow. These seven wells are shown in red on the map. The Willow wells will help to further define the resource range because we have yet to encounter gas or water contacts. These wells will also help optimize the placement of our pads.

Now it could appear that we're drilling a lot of appraisal wells at Willow, but bear in mind Willow is over 25 miles long and 10 miles wide, so the appraisal-well density is not out of line. The 2020 appraisal season will collect the data we need to finalize our design for Willow and Narwhal.

Now on our acreage, 75% of the exploration portfolio is undrilled. Harpoon is the next in the series of prospects to drill. Harpoon has a similar seismic signature to Willow and Narwhal, but the seismic suggests this area has the potential for stacked pay horizons.

So going back to Willow and Narwhal. Let me show you what our technical teams are working on for these developments.

To develop Narwhal, nearly half of the development wells will be drilled from our existing CD4 pad, and we expect production into our existing Alpine facilities in 2022. We'll also build a new pad, CD8, to access the remaining Narwhal inventory. We plan to start production from that pad in 2025. The Narwhal development wasn't in our plan last year, but is now based on the encouraging results we've seen.

Now at Willow, we already know that Willow will be a new hub for the North Slope with the conceptual pad layout something like this, with three to four drilling pads, a central facility and other supporting infrastructure. We're using the plateau optimization model that Matt mentioned to size the development. We expect to FID the project in 2021 and have first production in the 2025-to-2026 timeframe.

In the 10-year plan for Willow and Narwhal -- for the Willow and Narwhal developments, we have $6 billion of capital, with total peak oil rates of 70,000 barrels a day, net. Our engineering teams are working options now on facility sizing, module construction and transportation. However, the details of this configuration and the facility sizes are yet to be fully landed. For example, we're considering an alternative that would increase capacity and redirect GMT2 to Willow. This would open up capacity at Alpine for incremental Narwhal and ERD production.

Our total overall resource range from Willow and Narwhal has increased to 600 million to 1.2 billion barrels with a P50 of 900 million barrels and a cost of supply of the base plan of $35 a barrel.

So here's the punchline. The Narwhal and Willow discoveries are bigger and better than we originally thought. Our engineering teams are working options now to optimize these developments using available capacity and existing infrastructure across the North Slope and optimally design the new facilities to lower the cost of supply even further across all of these developments. And there's a possibility to make these developments even more attractive as we learn more from our appraisal activities and engineering studies. So more to come next year.

Now this is an aggregate view of our Alaska production over the next 10 years. It starts with maintaining the technical and operational discipline to optimize our base operations. We build on the base of continued development drilling in our core area along with the other projects that will be executed in the coming years. Compared to last year, Narwhal is in the plan and Willow is better than expected. Willow was the step-change of our long-term growth story when it comes online in the middle of the decade with significant and high-margin production. And with additional exploration prospects to drill across our acreage, in the coming years, there's considerable resource upside. Remember, 75% of our exploration portfolio is undrilled.

And just a reminder on the right, our Alaskan production is roughly 95% oil. It typically trades at Brent, not WTI. And today, receives a premium to Brent, which helps drive these compelling financials.

Now lastly, in this 10-year period, across our Alaskan assets, the total gross investment is about $25 billion. These investments increase production from our fields and more than mitigate the current decline through TAPS. In fact, as a result of these investments, we believe production through TAPS will increase. This will create a very economically advantaged future for the state of Alaska.

With that, let's move south to Canada. We have been on a relentless drive to improve our oil sands business at Surmont. Over the last few years, we've reduced our cost of supply from $46 to $30 a barrel. This 35% reduction has come about from innovation, such as improving our netbacks through commercial activities like the dual diluent project which we recently started up at CPF2. This gives us the ability to switch between condensate or synthetic crude or a combination of the two to blend the bitumen. This is turning Surmont into one of the most flexible, commercially advantaged oil sands plants in Canada.

We've reduced the capital cost of our drilling, completions and well pads by optimizing the designs of our wells and reducing the size of our pads. Through activities like using data analytics to optimize our steam allocation, we've reduced our lifting costs 13%. Additionally, over the last three years, we've improved our operating performance and reduced our emissions intensity by 16%. This is largely driven by the implementation of our innovative non-condensable gas injection process. With this process, we inject gas, along with the steam, to form a thermal blanket over the steam chamber and reduce the heat loss to the overburden rocks. We're continuing to expand implementation of this technology across the field.

Our Surmont development area is highlighted in the northern part of this map. This area contains 1.1 billion barrels of net resource with an average cost of supply of $30 a barrel. As you can see, there's significant resource upside. This resource is similar in quality to the current development area and is accessible with current technology from our central processing facilities. From these existing locations, our evaluation indicates that we can access an additional 1 billion barrels of net resource as shown to the south of the development area.

We're looking at potential low-cost supply options to access these additional resources. This is upside to our current plan.

Now in Northeastern British Columbia, our Montney unconventional asset is entering an exciting phase of growth. Let's look at that now. Over the last five years, we have leased, bought and traded into a position of more than 150,000 acres at an average cost of $1,500 an acre. And on our acreage, we now see 1.8 billion barrels of resource. As Montney grows, we expect to one day be talking about the Big 4, not just the Big 3.

Montney's cost of supply is around $30 a barrel. One of the drivers of Montney's competitiveness is the quality of the liquids stream. Liquids on our acreage are half of the production mix. 55% of the liquids are condensate. Our condensate is 52-degree API, and there's demand from Canadian bitumen producers to use this high-API product as diluent. Over the long term, we expect condensate to trade at relative parity to WTI in Canada. This is one of the reasons our Montney position has such a low cost of supply.

Another important aspect is the high productivity of our Montney wells. Montney's well EUR is over 1.7 million barrels of oil equivalent. This helps drive down the capital and operating components of the cost of supply stack. The resulting effect is that cost of supply in this part of the Montney is competitive with the best unconventional plays in the Lower 48. This, plus the scale of our resource position, is why we expect to soon be talking about Montney as part of the Big 4.

Our first phase of development is well underway as you can see on this next slide. We finished drilling and completion activities on the first 14-well pad and finished drilling on our second 9-well pad. With the graphs on the right, you can see our drilling and completion execution on these early pads is demonstrating that we can achieve our manufacturing-mode cost targets. We're testing spacing and stacking in our completions across three and four layers, bringing in learnings from our Lower 48 shale developments.

Our Montney gas plant has been delivered on-schedule and under-budget. We've commissioned the plant and are currently waiting on a third-party pipeline before ramping up production. We expect the pipeline to be completed in mid-January, and the first pad will start up immediately thereafter. We're utilizing the plateau-optimization model, which Matt described, to determine the optimal rig level for this asset. As a result, in our plan, we had a second rig in 2023 and a third rig in 2027. This will allow us to match the pace of development with our infrastructure build-out and offtake commitments.

We expect Montney to grow significantly into the next decade. We expect to plateau in the mid-2030s with just three rigs at over 250,000 barrels a day.

So let's move over to Norway. After 50 years, it's still a key legacy asset in the portfolio and has additional upside. Although these are well-established assets, we're still finding opportunities to add value. Several examples are shown in the top of this slide. Our development drilling program utilizes technology like the ultra-deep resistivity tool. It has a depth of investigation about 10 times that of conventional tools and allows us to more effectively place our horizontal wells, driving down their cost of supply.

The second thumbnail shows a 50% reduction we've achieved with our drilling and completion costs as a result of renegotiated rig contracts and improved drilling execution. In today's plan, our ongoing drilling campaign at Ekofisk and Eldfisk provides over 100 million barrels of resource at a cost of supply of around $30 a barrel.

The third thumbnail depicts how we've significantly reduced our emissions and operating costs over the last couple of decades. We've implemented projects such as installing subsea electric power cables between platforms, electrification of cranes and installation of hybrid power systems for supply boats. Deliberate actions like these have made our Norwegian operations the lowest greenhouse gas intensity in the portfolio.

When we combine our development drilling programs with the low cost of supply projects near our infrastructure, our base decline rate of 14% is offset to an aggregate decline rate of 4%.

So let's look at these upcoming projects. We have four projects lined up over the next decade -- Tor II, Eldfisk North, Tommeliten Alpha and some additional satellite tiebacks. We'll use innovative minimal structures, either subsea or unmanned, to cost-effectively deliver these attractive opportunities. These four projects have a combined resource of 100 million barrels. These projects are great examples of the work that has gone into reducing cost of supply. Several years ago, these projects did not compete in the plan, but after achieving capital and cost improvements they now have a cost of supply of $20 to $30 a barrel.

In Norway, we also see exploration potential. We'll drill three operated exploration wells in the prolific Utsira High area of the North Sea through the remainder of this year and into next. The first well in the program was the Busta well, and it was a discovery in October. We're still evaluating the data we collected, but we logged 80 feet of high-quality net pay. Initial results indicate the potential for a gas/condensate play in the [Brae] formation. This is an area that's easily accessible via tieback to existing infrastructure. More to come on this opportunity.

Next up is the Enniberg prospect, which is near Busta, and is targeting the Jurassic Statfjord formation. We've recently spud this well and expect to reach TD in January.

The third well in the program is the Hasselbaink prospect, and it targets the tertiary-age Boulder formation. We expect to spud that well in January.

We also continue to evaluate exploration acreage in the annual license rounds. We were recently successful in adding several attractive opportunities, which we expect to drill in the coming years within our $300 million corporate exploration program.

In closing, I want to take a moment to emphasize our strong commitment to sustainable development across ACE. In Alaska, we're a leader in environmental stewardship, with decades of relationships and extensive environmental data to help us adapt and inform our work. For example, we utilize scientific environmental data that we gather to inform our engineering designs in order to minimize our impact on the ecosystem. In Canada, we're a founding member of the Faster Forests consortium. In the last 10 years, this group has planted over 5 million trees in the boreal forest. And in Norway, I've already mentioned the excellent work we're doing to reduce emissions.

So in summary, ACE is a microcosm of ConocoPhillips. In Alaska and Norway, we have large legacy conventional businesses with development drilling, project opportunities and exploration. In Canada, we have a stable, profitable oil sands operation with low sustaining capital and an emerging unconventional development in the Montney that we expect to offer significant long-term growth. And across the whole ACE portfolio, there's upside from exploration, additional resource conversion and further optimization. In our plan, these assets grow at a compound rate of 5% a year, but more importantly in the second half of the decade, generate strong cash flow growth and deliver total free cash flow of $16 billion.

With that, I'll turn it back over to Ellen.

Ellen DeSanctis ***ConocoPhillips Company - SVP of Corporate Relations***

Well done, gentlemen.

We're going to take a break. We'll resume at 10:15 in the morning.

Thank you very much for your attention so far, and we'll see you promptly at 10:15.

(Break)

Ellen DeSanctis ***ConocoPhillips Company - SVP of Corporate Relations***

Welcome back, everybody. Thank you very much for being on time.

We're going to start promptly now. And it's my pleasure to introduce Dominic Macklon, who will cover the Lower 48 region.

Dominic Macklon ***ConocoPhillips Company - President of Lower 48***

Well, thank you, Ellen, and good morning, everyone.

I'm pleased to complete our regional overviews today with the Lower 48. Now all of you understand that the shales have changed the game for our industry. What we're going to describe today is how we apply a very different approach to the plays that we believe continues to set us apart.

So as I cover the material today, you will hear three consistent messages. First, we're developing our high-quality, unconventional assets at an optimized pace that delivers exceptional returns and free cash flow, and resilient returns through the cycles. Second, our outlooks are based on prudent and proven assumptions around costs and well spacing and stacking, our reliable and predictable outlook. And third, we have line of sight to resource upside not yet factored in, so we expect more upside ahead.

Now our Lower 48 assets are already performing well and delivering strong free cash flow. And we anticipate a growing wave of free cash flow ahead. At our reference price, we expect the Lower 48 to generate approximately $19 billion over the plan, 90% of which will come from the Big 3.

In the Eagle Ford, we're a leader in what is the premier unconventional basin with tremendous running room ahead. And that's because from the start we focused on doing it right, not doing it fast. In the Bakken, we are outperforming our expected plateau rates. And in the Permian unconventional, it's still early days for us. But today, we'll show you a plan where this asset grows to become even larger than Eagle Ford in the next decade. And finally, our conventional legacy assets, primarily in the Permian Basin and also in the Gulf of Mexico, in today's plan they provide low-decline, strong supporting free cash flow.

Now I won't say much else about those assets today. My focus will be on the Big 3 where we have a growing low cost of supply resource.

We now have 6.5 billion barrels, less than $40 cost of supply in the Lower 48. Six billion barrels of that is in the Big 3, and that's grown by about 1 billion barrels since our last Analyst Day in 2017. Now greater than 97% of those increases have been organic, driven primarily by successful results in additional ventures in the Delaware and improved well performance in the southwest area of Eagle Ford.

Now looking at the stack, you see the significant resources in Eagle Ford and the Permian unconventional. Over 2.5 billion barrels in each case. And this is the very high-quality resource position underpinning our high-return, growing free cash flow outlook for the decade. In the plans you have seen today, the Lower 48 is expected to be the fastest-growing region in the company. We plan to employ about 50% of the capital which will increase our production from approximately 500,000 barrels a day to around 800,000 barrels a day by the end of the decade. And with very strong cash margins, around $25 a barrel at $50 WTI.

And I want to make a really important point here. We are not driven by production targets. Rather, we are driven by capital efficiency, returns and free cash flow. And as Mike discussed earlier, we have developed an investment criteria to optimize development for every asset in our portfolio, and we have applied that directly to our unconventional assets. So I'd like to briefly explain now how we have done this.

So in 2017, you'll recall, we set out a three-year growth plan as part of our strategy to expand cash flow, and we are successfully delivering on that plan with an expected compound annual growth rate of 22%, projecting we will generate around $3.5 billion of free cash flow during the same period.

So the question is, what should our future investment pace be? And this is where we've applied the optimization methodology described earlier. So for each of the Big 3, we have built integrated models that honor the unique aspects of our fields and allow us to create asset-specific NPV curves and incremental cost of supply curves. Now it's interesting to note that the important variables that influence the shape of the cost of supply curves include infrastructure capacity, well inventory by type-curve area and simultaneous operations constraints. That is how many rigs and frac crews you can run simultaneously in close proximity.

So as an example, we can see how this looks for Eagle Ford. So here again, you can see the NPV and incremental cost of supply curves plotted against plateau rate, or an unconventional case, rig count. And just as Matt explained earlier, this specific example for Eagle Ford reinforces two really important insights.

First, even though we're applying a less than $40 cost of supply threshold, we're still capturing 96% of the NPV. And second, the difference in optimal rig count between the maximum NPV pace and the less than $40 pace is very material. It's four rigs. So with corresponding infrastructure, this would require around $1 billion of additional capital per year or $10 billion over the next decade for very little value. So by using this methodology, we have defined plateau rates for our Big 3 assets that we project will allow us to deliver exceptional returns in free cash flow and maintain consistent, resilient investments through the cycles, and we are still capturing more than 95% of the NPV. So this is an approach that is clearly very supportive to our company value proposition.

I'd like to turn now to our asset overviews, beginning with Eagle Ford. So Eagle Ford continues to be a premier asset, we believe with decades of free cash flow ahead. We project $12 billion in the next 10 years alone. And the modeling I just described, determined our optimal plateau rate to be approximately 300,000 barrels a day with eight rigs. So that's up from our current rate of approximately 215,000 barrels a day with seven rigs, and we plan to add the eighth rig early next year. So more growth ahead for Eagle Ford.

Now it's really important to note that we still have only drilled 25% of our identified inventory, and after successful results from our refrac program, we have added 300 refracs to our base plan. On top of this, we have recovery enhancement pilots underway that provide further upside potential not yet built into our resource base. So Eagle Ford is an asset that still has significant remaining running room. And it's not just quantity of remaining well locations. It's also the quality.

So for those of you that have followed our Eagle Ford development over the years, you're very familiar with the relatively moderate pace we have taken, focused on learning and technical optimization. And this leaves us not only with differential remaining running room but also differential quality through optimized spacing and stacking.

So if you look at competitor acreage offsetting ours, you will typically see a single-layer development strategy that was executed at a very rapid pace, particularly during the 2013 to 2015 period, and this has resulted in the vast majority of the offset operators' remaining child well locations being subject to significant degradation, more than 28 -- sorry, more than 20%.

In contrast, we have developed an optimized spacing/stacking approach. There are different solutions for different parts of the field, but a typical example is this triple-stack multilayer co-development. So as a result, we have preserved the majority of our remaining inventory with minimal degradation. That is the majority of our remaining inventory at Eagle Ford are parent-like wells. Now it's also important for me to emphasize that for those child wells that will be in the degradation zone, we have modeled-in appropriate degradation factors. So you should not expect downside surprises. In fact, with the refracs and the Vintage 5 completion technologies that we'll talk about shortly, we see upside in further mitigating child well degradation.

Now you might be thinking, okay, they've done a good job minimizing future degradation, but is ConocoPhillips' well spacing and stacking strategy delivering competitive recoveries and cost per barrel? Well, the answer is yes, and I can demonstrate that with our updated benchmarking analysis.

Now you will see many different metrics being used for benchmarking, many highly curated and many that focus on very short-term IP rates. But the metrics that we regard as most meaningful to assess our competitive performance when it comes to investment returns are 12-month cumulative oil production. So we consider the first 12 months as the first significant economic period. Not 24 hours or 60 days, for example; estimated ultimate recovery, which, of course, is strongly informed from the first 12-months decline curve; and finally, the well CapEx per BOE. And we have plotted this here for EUR, but you can observe you would have similarly competitive results if plotted on a 12-month basis. So we continue to pay close attention to this data, and you can see we continue to be a leader in the basin.

Now also of significance is that we're achieving greater than 20% recovery factor, greater than was historically ever thought possible from the shale reservoirs. But a key message today is that we believe we can do even better. Economically increasing recovery factors remains a significant opportunity for us to add low cost of supply resource organically. And in the next few slides, I'm going to show where we've had some recent success, along with an update on the recovery technologies that represent pure upside to our plan.

So this year, we have made significant progress proving up our mechanical isolation refracs. Now looking at the top left-hand side of the graphic illustrates the concept, simply that we are recompleting all Vintage 1 and 2 wells with much more intense Vintage 4 completions.

Now it's important to understand that these are mechanically isolated, meaning that we are installing a casing liner within the original lateral we're cementing and recompleting, and this is key to their success. So we now have 15 refracs online with an average 75% increase in forecast well EUR. Our base plan includes 300 refracs with a cost of supply less than $30 per barrel, with further upside beyond our plan.

Now another important feature of these refracs is that 80% of them are on parent wells that will be stimulated at the same time as their neighboring child wells. And this will significantly reduce degradation by achieving a much more symmetrical frac pattern in the child wells. And RS Energy recently published a paper recognizing our success here called, "The kids are going to be all right." So our refracs will help drive up our recovery factor, but there are other ways we are looking at to add upside that's not yet built into our plan.

So in July this year, our reservoir engineers published a technical paper that is summarized in this slide. At the top of the graphic, we illustrate a small section of horizontal production wellbore with two perforation clusters. In our Eagle Ford stimulated rock volume pilot, which you've heard about us talk previously, we gathered horizontal core data parallel to the wellbore about 70 feet away. And there are two key insights we discovered.

First, we observed many hydraulic fractures, actually, many more than we expected. And these are represented by the ellipses on the core diagram. Second, while we were able to observe proppant grains and their related embedment pits in fractures adjacent to the perforation clusters, and those are the sand-color ellipses, the fractures between the clusters had little to no proppant. And those are the gray-colored ellipses.

So in essence, our stimulation design at the time was creating a lot of fractures but not allowing proppant to travel to fractures in between the clusters, certainly a more tortuous path, and this results in a lot of unpropped fractures. And we know that unpropped fractures close up as pressure depletes. So building this knowledge into our simulation models demonstrates the impact this will have on recovery factor, highest recovery from prop fractures adjacent to the perforation clusters and lower from unpropped fractures in between the clusters, which provides the design basis for our next vintage of Eagle Ford Completion, Vintage 5. So with V5, our primary goal is to improve proppant placement.

An important secondary objective is to increase the tessellation of the frac pattern. Now as I'm sure you all know, a well-tessellated pattern has no overlap and no gaps. So the illustration showing two neighboring wells demonstrates the concept between V5 versus V4. You see more prop fractures, less overlapping gaps in the fracture pattern between neighboring wells. Now also worth noting that a more tessellated fracture pattern would also help to reduce child well to parent well degradation factors.

Now it's important to say for various reasons, including pressure-related fracture behavior, we are not expecting dramatically higher IP rates with V5. Rather, the Vintage 5 wells are all about driving a material improvement in recovery over time.

Now our V5 pilot tests are progressing well. We have 10 pads planned in total at Eagle Ford, with three pads online to date and a fourth by year-end. We will also have a V5 pad coming online at Delaware early next year. And the chart shows the average performance of the Eagle Ford pads so far.

So we are beginning to see separation and improved performance, but it's still early days. We expect to have the data to make a full field decision on V5 application by early 2021. A reminder, this upside is not yet built into our outlook. When it comes to economics, our V5 designs could impact full well costs by about 5% to 10%, and we're targeting a 10% or greater improvement in recovery to go to full implementation.

Now finally, for Eagle Ford, a brief update on our further -- and a further upside recovery technology not yet built into our plan, and that is enhanced oil recovery. Now unlike some of our competitors in Eagle Ford, 60% of our acreage has naturally high volatility and does not require EUR. However, there is opportunity for increased recovery on the remaining acreage. So we are progressing three natural gas injection or huff-and-puff pilots with encouraging early results and indications of long-term, low cost of supply increase in recoveries. We expect to see conclusive recoveries in 2020, after which we would build a program into our long-term development plan.

So this wraps up Eagle Ford, a premier asset that we expect will deliver exceptional free cash flow over the plan, and we believe we have significant remaining running room, with further organic resource upside that can drive value for ConocoPhillips for years to come.

So now on to Bakken, the most mature of our Big 3 unconventional assets, yet still, we project a very strong decade of free cash flow ahead. Bakken is in the plateau phase. And if I ask you to cast your minds back to November 2017, in our last Analyst Day, you'll recall our expected plateau rates were in the 70,000 barrels a day range. Well, as you've noticed from our results year-to-date, Bakken is outperforming expectations, with a plateau rate outlook now of between 90,000 and 100,000 barrels a day. So this is a step-change in expectations, in part driven by our completion design and execution efficiency over the past 18 months. Now of course, approximately 40% of our back-end production is operated by others, and we have also seen improvements in our key partners' completion performance.

So we anticipate that Bakken will contribute about $3 billion of free cash flow over the next decade, and we have further resource upside from an emerging refrac program that is not yet built into our outlook. So using the very same methodology we have successfully applied at Eagle Ford, we're about to bring on our first three refrac pilots in Bakken this quarter, and we have approximately 300 candidates identified at Bakken.

Now just as for Eagle Ford, we keep a very close eye on our competitive performance. You can see we continue to do well in the Bakken. However, we do have opportunity to improve our underlying results. As more of our new well completions come online over the coming year, we do expect to further improve our ranking.

So next, I'd like to share more about the breakthrough we've had in our completion design in the Bakken. So in 2017 and early 2018, we performed multi-variate analytics on relevant industry well data to seek to understand the sweet spot in completion design in our primary zones, the Middle Bakken and the Three Forks. Now unlike recent trends in other basins, where more intensive completions have still been successful in driving higher returns, we saw indications that less-intensive completions might drive higher returns in the Bakken, particularly given its relatively higher permeability versus the other unconventional plays. Now in fact, it was more complex than this. Some aspects were less intense and others more so. We found three drivers that really mattered -- tighter cluster spacing, lower proppant and lower proppant-to-fluid ratio, suggesting an opportunity to improve recovery factors near the wellbore.

So we've baked these insights into our design, and the results really have been tremendous. With less proppant, our completion time and costs have fallen, and yet, our well productivity has increased, all resulting in a $2 per barrel cost of supply improvement. So improved production and faster completions is the primary driver for our outperformance on plateau rates in the Bakken.

And Bakken really is a model of how we're approaching the unconventionals. Get to optimal plateau, generate strong returns and free cash flow, keep learning, find upside and increase value. And that's a great segue to the Permian.

So finally, for asset overviews, I'll cover our Permian unconventional portfolio. Now typically, we have only talked about the Delaware. And while that's still certainly the largest of our Permian unconventional resources, we are also, today, including our high-quality Midland Basin and Northwest Shelf acreage. And together, we expect that the Permian unconventional will become the largest producer of the Big 3 assets over the next decade, eclipsing even Eagle Ford.

So the map here highlights our core development acreage in the Delaware, around 90,000 net acres, the Northwest Shelf, where we have around 20,000 net acres, and 60,000 net acres in the Midland Basin.

So for the Delaware, our plateau modeling work has identified an optimal investment pace of six rigs, and this compares to our current two to three rigs. And then we have a further four-rig split between the Northwest Shelf and the Midland Basin from the middle of next decade.

Now along with the rest of industry in the Delaware, we are still very much on the steep part of the learning curve, particularly around well spacing and stacking. This is the primary reason we have elected to pursue a moderate ramp-up pace in the Delaware so we get it right. Now we believe the Permian will be our next high-margin growth engine, and we expect this asset to contribute around $4 billion of free cash flow over the next decade. And with Delaware already producing over 50,000 barrels a day at $50 WTI, Permian unconventional should be free-cash-flow-positive from now onwards.

Now despite our current relatively lower activity, we already benchmark competitively across the same three key metrics looked at for Eagle Ford and Bakken. And this is due to our very high-quality acreage position in the Delaware, along with our ability to learn not just from our own operations but all of industry operations around us. And we expect to do even better on our competitive positioning as we approach true manufacturing mode in the coming years.

So with up to 12 benches across 4,000 feet of productive interval, the resource density and rock quality in the core areas of the Delaware is unquestionable. But obviously, industry analysts are intensely focused right now on the optimal development strategies. Optimizing well spacing and stacking within the ventures and the simultaneous development of ventures are crucial for sustained strong returns and free cash flow. So just as we have done in all our unconventional plays, we are taking a very methodical approach to this.

So first, I'd like to highlight that while we are optimistic about all of these ventures, indeed we have already tested 11 of them on our own acreage, we project that 90% of our Delaware production over the next decade will be derived in primary zones in which we have very high confidence, as the Wolfcamp A and C at China Draw, and the Wolfcamp A and Bone Spring second sand at Zia Hills. This confidence is based on around 800 existing industry wells close to our core positions, with at least 12 months production history. In fact, those 800 wells are all within this map, 798 to be precise.

And you'll be well aware that other operators have been piloting different ranges of spacing assumptions in this part of the basin, including some pretty aggressive tests of more than 20 wells per section in the Wolfcamp A. Well, we too have experimented with spacing and stacking, but our results indicate for our core acreage optimal spacing is in the range of 12 to 16 wells per section. And that's the range we are in. Now we will continue to hone in on this, but we believe we can deliver this 10-year production and free cash flow profile anywhere within that range of spacing.

So we have high confidence in the resources and the spacing and stacking premises for these primary zones. For the many other benches across the stack, we are bringing our full array of proven subsurface technologies to efficiently evaluate and design optimal development. We call it solving the stack. And this slide is a great example of how we transfer knowledge and technology between our unconventional plays.

Now given the multiple zones in the Delaware, technologies that help accurately characterize interzonal pressure communication are particularly valuable. So I'd like to highlight the two on the left-hand side, time-lapse geochemistry and microseismic, both of which are really helping in this regard.

So with time-lapse geochem, by sampling hydrocarbons and analyzing geochemical fingerprints, we can allocate produced fluids to specific zones using reference data from rock core or cuttings, and this is highly valuable data in understanding zonal contributions.

Below that is the microseismic example. This shows data recorded from two Wolfcamp C wells on the same pad while being stimulated, dark blue dots from the first well and the overlying purple dots from the second well. A very similar pattern on both wells. Now to briefly explain, microseismic geophones record the sound propagated when the rock is fractured, and the dots are indicative of fracture geometry within the Wolfcamp reservoir interval. This can then be interpreted as stimulated rock volume, or SRV.

And what we have seen from this is that the majority of the fracture events stay within the Wolfcamp C, that's the lower cloud of dots, but we can also see a smaller upper cloud of dots. And that is located in the Wolfcamp A, about 500 feet above. So these indicate fractures have the potential to create short- and long-term pressure communication between the Wolfcamp C and the Wolfcamp A. And that could very well lead to significant parent-child well-type degradation, if not simultaneously developed. So early understanding of these interactions enables our teams to optimize simultaneous loan development and minimize degradation losses.

So we are integrating all of these aspects of applied science with actual well performance data to ensure we optimize development planning as we prepare to ramp towards manufacturing mode in the Permian.

So this completes our asset overview to the Lower 48 today, but I'd like to now turn briefly to cover what we're doing across the business to optimize our margins. Starting first with the sort of cost side, we take a life-of-field view of the development of our unconventional assets with a clear mission to ensure our field design and operating philosophy are structured to maintain the most competitive costs and margins that we can, and we really have developed a clear ConocoPhillips way of doing things that can be fairly, simply described in three key areas.

First, we want to minimize the number of moving parts in our facilities. This minimizes maintenance costs, maximizes reliability. In this regard, gas lift has huge advantages over rod pumps and other mechanical artificial lift systems. So we've implemented gas lift across the Big 3.

We are also an industry leader in the application of digital technologies to maximize remote monitoring and control. A very recent advance was a successful field testing of new, low-cost, wireless conditioning, monitoring IoT devices. So these allow us to significantly expand conditioned monitoring data across our plant and equipment at very low cost, in a similar way that wireless devices have had a profound impact on the cost and ease of installation of building alarm systems. And more data means more insight and the opportunity for greater operating efficiency.

Of course, we already gather vast amounts of data across our operations, which is immediately accessible by our engineers and data scientists via our integrated data warehouses, and we continue to advance our analytics capabilities to increase effectiveness of our maintenance and reliability programs.

Automation and machine learning applications are also developing rapidly. As an example, we are working to create a machine learning capability that will automatically optimize distribution of gas lift across thousands of Eagle Ford wells. Now bringing this all to the bottom line, based on existing proven technologies, our lifting cost outlook for the Big 3 already averages less than $4 per barrel over the decade, and we expect to leverage technology to continue to chip away at these costs. But it's not just about costs, it's also about price realizations, and we have robust commercial strategies in place to capture advanced netbacks.

Now as you know, we have a very strong heritage and capability in both gas and crude marketing from our days as an integrated company. And we are advanced in the process of implementing a well-defined, long-term U.S. crude marketing strategy that will deliver the majority of our production toward the Gulf Coast and on to international markets. We're developing a portfolio of long-haul pipeline capacity positions, with interconnectivity between the main basins, along with a diversified position of dock facilities along the Gulf Coast. Our export capacity will be more than 200,000 barrels a day by 2021, and our existing global marketing presence provides us with options for direct customer access.

Now it's also worth mentioning, we remain a top-five North American gas marketer, which is continuing to prove our strategic value in securing offtake in key basins, including the Permian, all of which contributes to enhanced realizations.

Now as I wrap up now, I'd like -- just as Bill and Michael did, I'd like to make a few comments on our commitments beyond the numbers.

So based on our spirit values as a company, we are committed to a responsible and sustainable development across each of the societal, economic and environmental pillars. Among the many stakeholder, health, safety and environmental actions we are taking, there are three key areas I'd really like to highlight.

First, water. Across the company, almost 90% of the water we use is either non-fresh ground water, seawater or recycled produced water. And a great example of our recycling efforts is in the Delaware Basin, whereby Q3 next year, we'll be using recycled water for 90%

of our operations requirements there.

Secondly, and on a matter of particular importance to our industry, we are among the leaders in methane detection and capture. We have completely eliminated high-bleed gas pneumatic devices across the Lower 48, and have been conducting voluntary leak detection and repair, or LDAR, programs for several years, using handheld optical gas imaging cameras. And we're advancing a range of additional initiatives to further increase gas capture and reduce emissions.

One example we successfully pilot tested this year are drones equipped with on-board gas analyzers. This technology holds great potential as an addition to our arsenal of LDAR tools. So our goal here is to advance this toward a facility-based drone system, which would automatically deploy to conduct regular flight path routines, transmitting data back toward our integrated operating centers. This concept offers a breakthrough in real time, cost-effective detection and subsequent repair of fugitive emissions.

And finally, reducing traffic. Not only does investment in gathering infrastructure for oil and water reduce our lifting costs, we will have eliminated more than 100,000 truck trips per year across Bakken and Eagle Ford, reducing traffic and improving road safety, something of great importance to our local stakeholders, as well as reducing emissions.

So across the Lower 48 region, just as across all of ConocoPhillips, we embrace our responsibilities to perform with purpose. And this brings me to my final slide.

And I'd really like to end how I began, with the three key messages I would like you to take away for our Lower 48, Big 3 business.

First, we're developing our high-quality assets at an optimized pace that delivers exceptional returns and an anticipated $19 billion of free cash flow over the decade, and returns that are resilient through the cycles.

And second, our outlooks are based on prudent and proven assumptions around costs and well spacing and stacking. So I believe we're giving you a reliable and predictable outlook.

And third, we have line of sight to resource upside not yet factored into our plan. So we anticipate there is more resource and financial upside beyond our base plan.

We believe our acreage positions and differential execution strategy in the Big 3 offers unmatched value creation for our owners that supports our company's commitments to free cash flow, returns on and of capital and sound stewardship of the business.

So thank you very much, and I'll hand over to Don now to cover the financial plan.

Don Wallette ***ConocoPhillips Company - Executive VP & CFO***

Dominic, thank you.

Since I'm in charge of the accounts of the company, I'd like to report the final official tally of the number of times we've said the term "cost of supply" today. It's 85 times. So congratulations to those who had the over on that.

Now you're not going to hear me say cost of supply because it's a non-GAAP measure, so far. We're working on it. Oh, 86.

We're going to conclude this morning's presentation with a review of a powerful financial plan that results from the investments that you've heard our previous speakers describe. We believe this plan clearly demonstrates our ongoing commitment to the shareholder-oriented value proposition we laid out three years ago and one that sets us apart from other energy investments.

I'll talk about our financial plan in three ways. First, on the left, I'll describe in more detail the most compelling aspects of our 10-year plan. They're listed here. A projected free cash flow of about $50 billion over the 10 years. Strong and growing returns on capital and distinctive returns of capital to our shareholders.

In the middle column, we recognized that prices could be lower, at least at times, than our reference price. I'll describe how we're positioned for the down cycles, with a top-tier breakeven price and a strong balance sheet. These are what allow us to maintain consistent execution through downturns.

We also routinely stress-test the resilience of our plans, and I'll show you an example of a stress case that demonstrates how we perform in an extreme low-price event.

And on the far right, our plan has significant upside exposure to high prices. Cash flow sensitivities are provided in the appendix, so you can estimate this upside within a range of prices.

I'll lay out our framework for how we think about allocating cash above our base plan. Our goal today is to demonstrate that we have a proven track record of value creation, and that we are well-aligned with shareholder interests across the cycles.

This slide will serve as the agenda for our financial plan discussion, and we'll begin with a review of our 10-year plan. Ryan spoke to this summary earlier, so I'm not going to linger on it, but it captures the key results of our 10-year plan.

Based on a $50 oil price, we anticipate generating about $120 billion of cash from operations, using about $70 billion of capital and generating $50 billion of free cash flow. The attributes of the plan are listed on the right. This is a viable, balanced, shareholder-friendly plan that should appeal to energy investors and non-energy investors alike.

Next, we're going to delve more deeply into the financial merits of our plan, beginning with our strong free cash flow generation. We made an early and sustained commitment to free cash flow generation. As Ryan described, we did this by attacking the underlying drivers of profitability and financial strength, not just by cutting capital and growth.

We've been free-cash-flow-positive for the past three years, which is well ahead of most of energy. The chart on the left shows our recent four quarters financials, and you can see that over this period, we've delivered free cash flow, represented about half of cash from operations.

On the upper right, we see free cash flow as a percentage of CFO for the trailing four quarters on a relative basis. And Matt described how our low capital intensity provides us a competitive advantage when it comes to free cash generation. We're in the top quartile versus competitors.

And as the lower right chart shows, we have one of the highest, forward-looking free cash flow outlooks. As you can see, in both charts, we're competitive with the integrated companies and quite distinctive compared with the independents. So we were early to get free cash flowing, we're in the top-quartile today and we retain a strong position on a forward-looking basis.

Next, I want to cover the expected financial returns from our plan. As Ryan said, our North Star is financial returns. The chart on the left represents a 2019 consensus view of return on capital employed. We're differential versus industry competitors at consensus prices. We lag the S&P, but we believe it's important to compare ourselves, not just to industry, but to the broad market. We'll win back sponsorship over the long term by offering disciplined capital allocation, with returns that compete across industries, and that is our goal.

On the right side of this slide, we have two charts that describe the earnings growth and financial returns that we expect our plan to deliver. On the top chart, we estimate earnings to grow from around $2 billion in 2020 to north of $6 billion by the end of the decade. So that's a 12% earnings CAGR over the 10-year period.

Of course, on a per-share basis, earnings growth is compounded by our planned buybacks. That earnings growth fuels the growth and return on capital employed over the plan period. That's shown in the bottom right chart. We project 2020 ROCE to be around 7%, but we expect to grow this by 1 to 2 percentage points a year over the decade. Our projection for 2029 is about 20%.

So we've covered free cash flow generation, and we've covered our outlook for profitability and returns on capital. Now let's talk about returns of capital and the underlying distributions philosophy that is central to our 10-year plan.

A core aspect of our value proposition is returning a significant portion of the cash generated to our owners. Not only does this represent a proxy for discipline, it helps drive superior shareholder returns over time. This slide describes how we think about the level of payout as well as the mix of distributions.

As for the overall payout level, our philosophy is to set a target that is competitive with the integrated companies and distinctive compared to the independents. The chart on the upper left shows we are very well-positioned amongst our peers. Our stated target is to return at least 30% of cash flows to owners, but importantly, we aim to meet or exceed that target on a consistent through-cycle basis. That's where our mix of distributions comes in.

We believe we've set a prudent mix of dividends and buybacks that offers a competitive distribution yield, with a return of capital that grows over time. Our four-year trend is shown on the lower-left chart.

As for the dividend, we set it at a level that is affordable at the low end of the price cycles. That's step 1. Our recent 38% dividend increase reflects a high level of confidence that we can sustain a new dividend because of our improved underlying financial strength. Once we set the dividend, we intend to grow it. That's step 2. Our goal is to grow the dividend at a rate that is competitive with the S&P, which generally averages between the mid-to-high single digits. We've done that since 2016, and in today's plan, we continue to do it for another 10 years.

As for buybacks, we believe they play an important role in our approach toward distributions as a supplement to dividends. Before initiating our program in 2016, we rigorously evaluated buyback performance across a long period of time and across many industries. Our conclusion was that dollar-cost averaging creates the most value over time and is especially important for cyclical industries, and that's how we've approached this distribution channel. The lower-left chart shows our track record. We revisit the level and mix of our distributions on a routine basis. Today's plan assumes we maintain a consistent approach over the 10 years.

I'll wrap up our base plan discussion with a summary of the key financial metrics our plan is expected to deliver. First, our strong free cash flow generation. Our base plan is free-cash-flow-positive in all years. This chart shows that our free cash flow grows from $3 billion in 2020, reaches $5 billion by mid-decade and finishes the decade at $7 billion. Cumulatively, we expect to generate $50 billion over the decade or an average of about $5 billion a year.

Next, I'll highlight our balance sheet strength. Over the life of the plan, our leverage does not exceed 1 times net debt to CFO at our reference price. You'll note that from 2020 to 2025, the leverage does increase slightly. This reflects the fact that we use cash on hand to consistently fund our planned capital and distribution programs.

I already addressed our financial returns outlook, so I'll just remind you that it is our primary objective. Returns are expected to grow, and that's one of the reasons we can deliver distinctive returns of capital. Our plan provides for distributing around $6 billion a year by the end of the decade via dividends and buybacks. That includes a consistent $3 billion assumption on buybacks as well as a growing dividend. We exceed our payout target across the plan and expect to maintain a highly competitive position amongst industry competitors. So you can see how powerful this financial plan really is and why we believe it sets ConocoPhillips apart. But we know that plans in our business must also be robust at lower-price scenarios. So let's talk about how we're positioned to deal with lower prices.

The middle column describes the characteristics that position us to win even with lower prices. That's what I'll cover in the next few slides. Recall one of Ryan's opening premises -- we must embrace the inevitable cycles of our business. To us, that means working in all parts of the cycles, even the lower-priced ones. Shown on this page are some of the downside case differentiators.

We have the recipe, and we share it freely because it's incredibly difficult to replicate. Low cost of supply -- OK, 87 times -- low capital intensity, low breakeven price and a strong balance sheet. That's all you need. It's only four ingredients, but they're really hard to find in one place.

We talked earlier about our definition of discipline in the context of consistent capital programs. Here, we extend the definition to also include our distribution programs. That's shown on the banner on the upper left. We used to think about discipline like most of industry, conservative when times are tough, flex capital when necessary. Now we think about discipline differently. Our plan aims to take the boom and bust out of our business for good, that's how you generate better returns.

Now I'll quickly cover these aspects of our resilience, starting with our low breakeven price. We believe our low breakeven price is a key differentiator. On the chart on the left, we lay out the breakeven prices required to cover our planned uses of cash over the period. Looking at the colored wedges, at the bottom is the WTI price needed to cover our capital program. This is what we call free cash flow price. This starts the decade at around $40 WTI that steadily improves with cash flow growth to sub-$30 by the end of the plan.

The dividend breakeven is shown by the middle wedge, and the buyback breakeven is shown at the top. Together, the distribution wedges represent about $17 per barrel returned to investors on average across the decade.

Our $50 reference price is indicated by the red-dotted line. As you can see, at this price, we anticipate being free-cash-flow-positive and able to fully fund the dividend across the 10-year period. However, operating cash flow at $50 oil doesn't fully cover our planned buybacks for the first five years of the plan. That's one of the reasons for maintaining a healthy amount of cash on hand, to provide for the consistent execution of the buyback program.

On the right of the panel, you can see how we stack up on capital breakeven versus our largest competitors. Again, we're differential. And this isn't something you can wish or even engineer. It's all about the quality of the portfolio we have and how we choose to allocate capital.

Next, I want to talk about our balance sheet's role in downside protection. The title of this slide says it all. In a cyclical business, a strong balance sheet is a strategic asset and you can't possibly win without a strong one. I won't spend too much time on this slide, but given that we've mentioned the strength of our balance sheet several times already, I do want to put some context to it.

Our debt level, shown on the left of the panel, has been reduced by $12 billion. That's a decrease of 45%. In the middle chart, our leverage ratio, and right now we barely have 1, is amongst the lowest in our industry. But it's not just debt reduction that's improved. Like every other part of our business, we've attacked underlying metrics and line items to make our balance sheet stronger. Our interest expense is 35% lower, which has contributed to improved income and cash flow. And we've reduced our asset retirement obligations by $2.5 billion or about 30% over the past three years.

In total, these and other actions represent about $15 billion of balance sheet improvements, which have put us in a very strong position. And our debt is now A-rated by the credit rating agencies. But the debt capital markets view our company quite a bit stronger. Our debt trades much closer to AA than A, which is really remarkable for an E&P company.

On the next slide, I want to address the role of cash as a source of resilience and also describe the stress test we've applied to our balance sheet that gives us confidence in today's plan.

First, I want to share with you how we think about cash on the balance sheet. And we think about three tranches of cash, each with a specific purpose and time horizon. The first two tranches are purely tactical and focused on running the business. We need about $1 billion of operating cash to turn on the lights and settle accounts on a daily basis.

The next layer, we call reserve cash. Here, we're looking out six to 12 months at our operating plan at the sources and uses of our operating plan based on strip pricing. This can be either a deficit or a surplus, but generally, it's a small number because we're generally balanced, well-balanced. But because the strip is going to be wrong, we also consider price volatility over this time period. We use options-implied volatility at the 95% confidence level and that results in reserve cash, usually between $2 billion and $3 billion. In other words, we have 95% confidence that our reserve cash will not be depleted over this time period. We recalculate this each quarter because outlooks and volatility change and also because our cash investment decisions are informed by the amount and time horizon of each tranche of cash.

As fascinating as that was, it gets even more interesting from here. Our final tranche, we call strategic cash. We call it strategic cash because it's there to support our strategy, and we spelled out the rationale here. For example, continuity of our buyback program is strategically important to us. But we showed earlier that at $50 oil we'll only be able to do that from cash flow after about five years. So we'll prefund those buybacks by holding cash. We also want to maintain continuity in both our capital and distribution programs, not only with respect to short-term volatility, but also in the event of an extended downcycle. And finally, operating opportunities may arise that are outside this plan, whether they be the development of exploration success or participation opportunities or resource acquisitions, and we'll prefer to fund those with the cheapest source of capital available, cash.

Given our definition of discipline and our desire to execute a consistent plan, we view cash as an important part of our value proposition. We plan to hold healthy cash balances, and we have a specific rationale for doing so.

To demonstrate just how much resilience our current cash balance provides, let me turn to the right side of this chart. On this chart, we're going to stress test the base plan in the years 2023 through 2025. We chose that time period because it's the most inopportune time in the plan when capital is rising, primarily due to our investments in Willow and our growth in the Permian.

Here's our base plan at $50. You can see, we retained a leverage ratio of less than 1 across the entire 10-year period. Now this is a much-simplified version of the rigorous stress tests we conduct, which are based on Monte Carlo price simulations and rating-agency models that have multiple metrics. The simplification we make here is to use a single financial metric, leverage ratio, as a proxy for credit rating. Our aim is to maintain a solid investment-grade rating at the bottom of the cycle, and that loosely corresponds to not exceeding a leverage ratio of 3 times.

We then stress test the plan by assuming the prices fall to $40 WTI and stay there for a three-year period. Now this is more -- this is a more severe scenario than any of the downcycles we've seen in the past 20 years, but it shows just how well-positioned we are to deal with adversity in the commodity markets. In this scenario, we take on a modest amount of debt, about $3.5 billion, and you can see that the leverage ratio peaks in 2025. However, we don't even breach the 2 times level. So we could withstand even lower prices before reaching our notional 3 times threshold.

The important thing to note is that while all this is going on, we're still executing our plan. We're continuing to execute our full capital program, we're continuing to increase our dividend, we're continuing to buy back $3 billion of shares, and by the way, those shares will be a great value for our investors.

Who has the combination of assets and financial strength to do this? Well you know that's a rhetorical question.

In this final section, I'll highlight our significant exposure to price upside and then discuss how we think about uses for cash flows beyond today's base plan.

Many competitors in our industry protect downside risk by capping upside exposure. We believe we've positioned ourselves for success through downturns, but without limiting our investors' exposure to price upside.

Shown on the right of this chart are some of the drivers of differential upside. Our portfolio is oil-weighted. About 70% of our cash flows are linked to Brent pricing. We're unhedged because unlike many E&Ps, we don't have to be. We're unencumbered by debt covenants that would require us to hedge. And given the freedom to choose, we choose to not limit our investors' upside to price. We have a few production-sharing contracts, but we operate predominantly in tax and royalty regimes, where we proportionately share in the upside. And just like in the downside discussion, we keep a close eye on our underlying cost structure. We're not going to lose financial or cost discipline in an upcycle.

Now let's talk about what would happen if prices turn out to be higher than our reference case. What choices and options could we consider? And how do we think about the relative merits of those choices? It doesn't take much price upside to imagine that we might have significantly more cash over the next 10 years. So how do we think about creating value above our base plan? The choices we have for allocating incremental cash is straightforward. There are three basic uses: we can return more capital to owners; we can add resources, organically or inorganically; or we can further strengthen our balance sheet.

We know there is a wide range of opinions on what we should do if we find ourselves with incremental cash. We also know that everyone would like us to provide a clear, formulaic answer as to how we would allocate cash above the base plan. But the truth is, it depends. We can't spell out a precise formula for every possible situation, but we can describe a framework for how we think about allocating incremental capital, and I'll describe that on the next page.

This framework describes several alternatives in each of the 3 allocation buckets I just described. It also describes the considerations and criteria that go into our thinking on each of the buckets. I'll cover these one by one, starting with additional returns of capital in the blue lane.

In this category, there are a number of ways we could think about increasing shareholder distribution. We could accelerate dividend growth, we could increase our buybacks above the $3 billion in our plan or we can consider special dividends, perhaps contingent on cash flows or cash balances.

If we were to generate significantly more cash than what we've described in the plan, then each of these options would be considered. Our choices will be shaped by our understanding of the reasons for the increased cash flows. Significant increases to the dividend or the dividend growth rate would need to be accompanied by a view that there's been a structural change in our ability to generate cash flow that's sustainable. For example, if we became convinced that our long-term reference price should be adjusted upward. If, on the other hand, we found ourselves with a windfall of cash because oil shot to $100, but we believe that to be unsustainable, then we wouldn't want to make structural changes to the dividend. And we also want to avoid procyclical buybacks. This is where contingent dividends become more interesting. But clearly, we're not currently in those circumstances. So it's not possible to be perfectly prescriptive. Our decisions will depend on the circumstances, but this is how we think about the various options.

In the green middle lane, we could also consider investing incremental cash to increase our resource base. Here, we also have several alternatives. We could increase investment pace across the assets currently developed in the plan, but as Matt explained, we believe we're investing at the optimal pace already. So that's unlikely.

That means incremental investment would be associated with incremental resource additions, and that could come from development of any exploration success we have over the next 10 years or by finding a way to lower the cost of supply of resources we've already captured, but aren't in the plan today or through acquisitions. And as we've explained, we apply a consistent set of criteria for investment decisions for all forms of resource additions.

Finally, we can further strengthen our balance sheet, as described in the gray lane on the right. The options here are to build cash, reduce debt or refinance debt. We've already emphasized the strategic role that cash plays in our approach to running the business in a consistent manner. So we're likely to maintain healthy cash balances, knowing cycles are inevitable.

We routinely evaluate opportunities to optimize our capital structure. Given our advantaged leverage ratio, we don't currently see any reason to reduce our debt balance, but we do recognize the opportunity to lower our cost of debt by refinancing a portion of our debt portfolio. Given historically low interest rates, this could be a good use of cash if the timing and economics work.

Now having discussed these three broad alternatives for unallocated cash, we wouldn't want to leave you with the impression that these are mutually exclusive, or even have a priority order to them. The fact is that they are likely -- there are likely to be good value-adding opportunities within each of these categories, and that's what you've seen us do over the past few years, is execute simultaneously in each of these areas.

We do know how to walk and chew gum and blow bubbles at the same time. You've seen us do it, and we like checking all of the boxes.

The bottom line is this. Our plan works based on what we've captured today. It works at $50 oil and it works across the cycles, and we expect it to continue working for the next decade. Any allocation of cash above our base plan must clear a high bar, whether it goes to additional distributions or to the balance sheet or to add high-quality resources.

We've worked hard to position ConocoPhillips to deliver superior returns through the cycles and any incremental investments must be consistent with that objective.

Now back to where we started with our agenda. But this time, it's a summary. I've stepped you through what we believe is a powerful financial plan that sets us apart. Our base plan is robust, balanced and responsive to shareholder interests and delivers on our targets. We can thrive across cycles. This is what investors want from energy, and this is how we've positioned our company for long-term success.

So at this point, I'd like to turn the meeting back to Ryan for a few closing remarks.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

All right. Well, thank you for your patience. So let me wrap up the formal presentation with the slide that brings us back to where we started this morning, and that's our 10-year plan on a page.

So our goal today was pretty simple. It was to establish that ConocoPhillips is the leader in a sustained, long-term approach to this E&P business that can drive across the cycles. And we laid out the details of that plan to do four things: they deliver strong, consistent free cash flow generation; leading returns on capital and of capital; resilience with upside; and a commitment to sound, responsible execution of the business.

We believe we've got the strategy, the portfolio, the financial framework and the world-class workforce to be the best E&P investment for all of our stakeholders.

So let's move to the Q&A. I'll invite Don and Matt to come back up to the podium for your questions. In the meantime, we'll have Jonathan and Mark will be working both sides of the room. I'm going to let them go to the people with their hands up, and we'll start with your questions. Thank you.

QUESTIONS AND ANSWERS

Mark Keener ***ConocoPhillips Company***

For benefit of those taking part via webcast today, please state your name and your firm's name before posing your question, and we'll get to all of you.

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

Phil Gresh at JPMorgan. First of all, thanks for such a thorough presentation. I don't think I've ever seen something so detailed from a bottoms-up standpoint, from an asset basis and a high-level basis as well. So thank you for all of this effort you guys have put in.

My first question is just the elephants in the room, the M&A side. I think you guys did a pretty thorough job of answering the question. But I guess, I wanted to ask it in a slightly different way.

Don, if you look at the way you've kind of framed out the balance sheet protection in the downside case and the advantage that, that provides ConocoPhillips, it would seem like it would not make a ton of sense to do a "significant acquisition" because then that would change the way that downside case will look, I'll say, significant at $10 billion-plus type of acquisition. You guys have done $1 billion or less worth of deals, and they've been very accretive. But is it fair to say that, that doesn't make sense, both for downside case protection as well as if we look at the return profile, trying to get to a 20% ROCE, that it doesn't make sense for that either? Just curious how you'd answer that.

Don Wallette ***ConocoPhillips Company - Executive VP & CFO***

Well, a good question, Phil. But I think it'd be impossible to rule out any. We've been, what, $400 million of acquisitions a year two years ago and maybe $300 million this year. There are different sizes that we could look at. I think it would be inappropriate to rule out all types of acquisitions or all sizes of acquisitions. What Matt did clearly lay out was our criterion for considering acquisitions of any scale. And one of those criterion was, it has to fit within our financial framework. We're not going to bust our financial framework to do that. So I think you're right in the sense that it's got to be consistent with the strategy that you've seen today.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

I'd add, Phil, it's -- I think what you've seen here, what we believe is a pretty compelling base plan. And we don't have to do anything. We've got something that works. But we also have a financial framework that we describe that how we think about the whole piece of the business. The resource additions, the exploration and the transfer of resources in our portfolio. We feel pretty pleased with where we're at.

Phillip Jungwirth ***BMO Capital Markets Equity Research - Analyst***

And just a quick follow-up question, I guess, unrelated to this, if you go back a couple of years, one of the components of your Analyst Day was not just volume growth, but also margin improvement potential, a 5% margin improvement potential. I presume of the margin improvement potential, there's an underlying element to that -- to the plan from that, but it wasn't maybe specifically talked to. So Matt, I wonder if you could maybe comment on that?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Yes, sure. Thanks, Phil. We still see margin improvement through the plan. But frankly, the 5% margin improvement that we -- the significant margin improvement, a lot of that has already occurred. I mean the margins continue to grow through the plan, but not at the same rate. So the cash flow growth is higher than the production growth. But it's not a particular feature because the underlying characteristics of what's going to grow are already a significant part of the portfolio. So a constant price that there is -- it's a combination of both, but the margin growth is less significant than it's been over the last few years.

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

Doug Leggate from Bank of America. Again, let me reiterate also that thanks for the detailed presentation. There's obviously a number of -- we're never happy with all the details. So I've got a couple of granular questions, if I may. Maybe to Matt. It looks like if we look at Slide 35, the unconventionals grow from about a third of the production today to about 60% of the portfolio by 2029 in the 10-year plan. What happens to the underlying decline rate? And what is the sustaining capital? How does that evolve over the period, given the shift towards higher-decline assets?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Doug, I think I tried to point out in the -- one of the slides, I don't know -- I don't remember the numbers of all of them, but the underlying base decline rate actually doesn't change through the plan even as production is growing because the new sources of production, sure there's a bunch of it that's unconventionals, but there's also offset and decline and the underlying base has a lot of conventional production, too, and there's some growth in the oil sands as well. So the base decline rate actually doesn't change over the plan, it stays at about 10% from year to year to year.

In terms of the sustaining capital, we didn't emphasize that this year. We've done that in the past. And the reason that we did that is we had a feedback from investors that, that's a really difficult number for them to reproduce, really difficult number to understand. Now the underlying sustaining capital is still $3.8 billion. The underlying sustaining price is still below $40 a barrel. If all we wanted to do was to sustain our production for the next decade at the current level, we could do it at that level. We've concluded that's not the most value-adding way to develop the resource. So -- and we've also decided to focus on metrics that you guys can reproduce. So breakeven prices and so on. But the underlying characteristics of the portfolio are unchanged from that perspective.

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

So just to be clear, I understand the three-year might not be important to a lot of people, but it's important to the way we look at it. So when the portfolio is so much bigger in 2029, what does that 3-year look?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Well, it grows about the same rate as the production grows. So to sort of sustain that -- as we grow production, the sustaining capital required to sustain that new production just gradually grows. But the thing that we're focused on -- for us, sustaining capital is a means to an end, is a means to understanding sustaining price. The sustaining price continues to decrease all the way through that period. So the sustaining capital gradually increases. What I was referring to the $3.8 billion was if we wanted to hold today's production for a decade, that's all it will take to do it. But as we grow in time then the sustaining capital gradually grows, but not -- nowhere -- no complicated math there.

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

My follow-up is maybe to Don. Don, I just want to be clear, the $7 billion of free cash flow at the end of the period, that assumes inflation on the oil price, it looks like you're about $61 WTI. Can you just walk us through what the sensitivities would be if it was $50 flat? What does that $7 billion free cash flow look like? I'll leave it there.

Don Wallette ***ConocoPhillips Company - Executive VP & CFO***

Well, no, you're right, Doug. The $50 WTI needs to be inflated 1.5% to 2%, whatever it is, over the 10-year period. We're providing sensitivities one year at a time so I can't tell you what it is in that 10th year. We'd have to go back and look at that.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

But one of the things to bear in mind, of course, Doug, is we are escalating our capital costs and our operating costs at the same rate. So both of these things are happening. If you really were in the world of flat prices, you probably would expect to see very limited inflation within our industry as well. So it's just that -- it's balanced from that perspective.

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

Paul Sankey at Mizuho. You've outlined, I think, if I heard you right, an outlook, which is essentially at $50 oil, with a range of $40 to $70. You're committed to rising dividends between 5% to 10% over the entire period with a rated $3 billion a year buyback that is a bit behind the curve in terms of breakeven for the next couple of years, but then it becomes more than manageable. It's a bit of a damned if you do, damned if you don't question, but I wonder if that's going to be just simply rated for the next 10 years, that buyback? It obviously amounts to a dividend but won't get the same rating in the market as it would if you did just put it into the regular dividend pot. So could you talk a little bit about perhaps whether that's going to, over time, become more part of the regular as opposed to buyback dividend, as, I guess, we see it sustained.

I think I'm on the right track here in terms of what you've outlined, I hope. So correct me if I'm wrong.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

No, I think you're right, Paul. I think as we think about it, again, you -- it's easy when you put a flat reference price of $50. But remember, it's going to be highly volatile. So as we think about the dividend, and Don described this a little bit, is we think about what's affordable through the cycle. So I've heard it before, the dividend is like marriage and buybacks are like dating. So we want to make sure that we can fund that dividend through the cycle. So that's why we've established what we think is an affordable dividend at the bottom end of the cycle that grows over time and grows competitively with our cash flow growth as well as the broad market growth. And then we supplement that because we have a goal to return greater than 30% of our CFO back to our shareholders. So we want to supplement that dividend with the buybacks, but we want to dollar-cost-average those buybacks because we can't predict what these volatile cycles are going to be. I don't think you'll see us, at some point in time, waking up and saying, $3 billion of buyback, if it's ratable, can we shove half or more of that back into the dividend channel. We're comfortable with the split and the way that we're returning cash to the shareholders as represented in this base plan.

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

And then the follow-up on the acquisition elephant. We've seen obviously a significant downturn in equity values. Is there major acquisitions out there that meet your criteria right now? Or have you set the bar high enough, let's say, that really there's nothing of interest for you because there's really no need to do anything?

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Well, I'll let Matt chime in as well. I mean we look at all the things that are in the market. I mean we're paying attention to what's going on with our fence-line neighbors, what's going on in the industry and what's going on right now. And so we look at a lot of things. But it's got to fit our financial framework, as you said, and that's difficult in the kind of market that we find ourselves in. Not impossible, but difficult.

Neil Mehta ***Goldman Sachs Group Inc., Research Division - VP and Integrated Oil & Refining Analyst***

Neil Mehta here with Goldman Sachs. Thanks again for the presentation. A couple of asset-level questions for the team. The first is around Qatar. And just how you're thinking about the North Field Expansion, in terms of timing. I know it's been a moving target, but also a desire to participate. And any incremental color you can provide as we think about that opportunity. And as we think about Qatar specifically, whether if you ultimately move forward with that, that would be incremental to the base case? Or would you substitute something else out in the base case to finance it?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

So the -- Qatar is running through a process that's been managed by Qatar Petroleum. They are in control of the pace, and we will move at the pace that they want us to move. I can't really say much more on what's going on with that from that perspective. In terms of incremental or a substitute of, it's more likely to be incremental, frankly, to this plan. We would not choose -- assuming we're offered the opportunity, we would not choose to participate in any project, Qatar expansion or anything else, if it didn't meet our cost of supply thresholds and if we didn't believe it will be a good addition to the portfolio. But assuming those things are true, then it would be an improvement to the plan. And we would find the capital to fund it.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And you've seen from the current portfolio, the power that the oil sands and some of the LNG, the low-decline assets, have on capital intensity that then has a forward-on impact to free cash flow generation. So those assets have a role in the portfolio. And I think what -- it is partly what distinguishes our company from our peers and our competitors.

Neil Mehta ***Goldman Sachs Group Inc., Research Division - VP and Integrated Oil & Refining Analyst***

The follow-up's on Alaska. In the press release, you indicated the potential for a 25% farm-down in 2021. Can you provide a little more color around that? It's just that to be more consistent with your position for other global assets? And just any thoughts on regulatory risk in Alaska as well, both around changes to federal lands rules or around the ballot initiative, would be appreciated.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Go ahead, Matt.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

So we have a prudent policy in place of not investing in large-scale projects 100% equity. We're not the only ones in the industry that do that, almost no one chooses to do that 100%. So it's consistent with our past practice and it was really -- that's what we're trying to explain. We have done a good job, I think, of capturing the value associated with having 100% equity there. We increased the position in the Western North Slope and in the Kuparuk at very, very reasonable acquisition costs. And we've since crystallized the value in the exploration portfolio. And I wouldn't underestimate that Nuna acquisition. That was a very valuable acquisition, too, that we've captured essentially 100% or close to it. So the strategy made a lot of sense for us. But going forward, to be consistent with our policy and to be prudent in how we balance risk across the portfolio, I think it makes sense to dilute some. And because that's part of our plan and because we want to be transparent with the market, we thought, okay, well, let's just explain that's what we intend to do. We're pretty confident we'll have a lot of interest in the -- I mean the Alaska, I think we've made the case there as one of the best few exploration plays in the world just now. So I think we're going to have significant interest there.

In terms of the permitting process, the permitting is underway. We're just going through an EIS comment period. So that is progressing very well. In terms of the Alaska, their Citizens initiative, which many of you may be familiar with, there's the potential for a ballot measure being on the November 2020 ballot in Alaska. It's called the Citizens initiative. It requires signatures, and it's not -- certainly not sure that it will be on the ballot, but it's a proposal to change the -- some of the characteristics of the fiscal regime in Alaska, that mostly focused on changing -- increasing the severance tax there. Now we don't know if it'll really get on the ballot. But if it does, then we'll have a conversation with the people of Alaska about, does that make sense? I mean we know that Alaskans are smart. Ryan and I both worked there. They understand their industry. They understand it's the lifeblood of the state's economy. They will see what Michael said was $25 billion of capital in this plan being invested just across the three assets we are involved in, plus about the same again in operating cost. They'll see that that's going to turn around the production in Alaska and actually make it increase again. So our sense is that once the whole dust has settled, then everybody understands what's at stake, Alaskans will understand that short-term revenue gain is a risky proposition if you're going to give up all this long-term potential. Because our investment plans would need to change if there was a change in the fiscal regime.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And this is our fourth go at it, Neil. I mean we've been through this -- we've been in this game before with the Alaskans. So it's nothing new. Who's next?

Paul Cheng ***Scotiabank Global Banking and Markets, Research Division - Research Analyst***

Paul Cheng, Scotiabank. I have two questions. One, three years ago, ConocoPhillips decided to exit deepwater. But since then, that you were looking at both the company financial position as well as the industry, it seems like the supply costs over there continue to drop. So is it enough change, both for the company and the industry, for ConocoPhillips to reconsider whether you want to reenter into that business on a longer-term basis? I mean if there's a countercyclical investment opportunity, it seems now deepwater is at least one of them today.

The second question is that if we look at your Eagle Ford, your remaining reserve today is about 2.5 billion barrels, according to the company, and you're already at 270,000 barrels per day and you expect to peak at about 300,000 barrel per day. So your RP ratio, call it, somewhere in the 23, 24 years. In Permian, you also identified resource today about 2.6 billion barrels, but you're targeting peak production around 400,000 barrels per day. And currently, you're probably about 50,000, 55,000 barrels per day. So by the time you get to close to peak production, your remaining reserve probably, that is somewhere in the 2 billion if there's no increase. So you're talking about maybe somewhere in the 15 years. So why there's such a big discrepancy between the 2 resources? Are you either overly conservative in your peak production estimate in Eagle Ford or overly aggressive in the Permian?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

So I'll deal with the Eagle Ford-Permian question first, and then you can remind me about the deepwater question, if I forget. But the -- it's actually, Paul, a fantastic illustration of the importance of having a consistent approach to the development of the unconventionals because their optimized plateau is not the same across these assets. In Eagle Ford, the plateau duration is a bit longer than it is in the Permian. And that's because the incremental infrastructure that would be required in Eagle Ford, new stabilization in particular, comes out in different sizes and different tranches and different costs than it does in the Permian. The Permian, they generally can be more just in time, and there's likely to be an overbuild of capacity in the Permian. So we do intentionally have a slightly shorter duration in the Permian than we do in Eagle Ford. And we have a longer duration in the Montney because of the nature of the timing and the commitments required to get infrastructure in place. This actually illustrates a great example of having a consistent view like this doesn't result in consistent answers -- 10 years or 15 years of plateau. It results in a consistent approach to incremental cost of supply across the different assets. So that's a good example for that one.

In terms of deepwater, we have absolutely no regrets of exiting deepwater and absolutely no intention of returning. We believe that there are better, lower cost of supply opportunities in other megatrends. Now sure there are going to be successes. And there have been successes where the cost of supply going forward for deepwater looks very attractive. But that's not the way you have to look at a deepwater exploration portfolio. You have to look at it across the cycle, you have to recognize you drill three dry holes for every one of those great discoveries you get. You have to recognize you can find yourself in appraisal hell, you have to recognize you have to pay bonuses to get it. You look at the cost of supply of the life cycle of deepwater, from our perspective -- I mean, others draw different conclusions, obviously. But from our perspective, it doesn't compete with the oil sands, for example, and we've got plenty of oil sands resource that we could compare. So I think it's very unlikely that we would be making any reasons to enter deepwater.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And I would add, the incremental G&A you've got to carry for the deepwater is considerable. So on top of everything else, and G&G and everything. It's the cost of supply that we don't believe competes in this portfolio, even with the reductions that you cite, Paul.

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

It's Michael Hall with Heikkinen Energy. I appreciate the time today and all the detail. I wanted to come back, I guess, first, at the micro level in the Permian and then roll up a little on the macro. But in the Permian, as we look at things, there's been quite a bit of variability across the basin. And in particular in the Delaware. I'm just wondering if as you look at the basin as a whole as a part of your portfolio, does that variability constrain or just limit the amount of capital you're willing to put towards the basin? And as you think about potentially expanding its role in the portfolio with any sort of A&D, does that, on its own, limit the ability of that to represent a bigger portion of the portfolio?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

I don't think so. But you're making there a very important point actually, and Dominic alluded to in his presentation that the Delaware is not all created equal, as the Midland Basin is not all created equal. In fact, over the last several years, we've sold a bunch of acreage in the Midland and the Delaware because our philosophy is, if you're not in the sweet spots, you shouldn't be playing. And other people wanted to have a Permian standpoint in their portfolio so we were happy to take money from them to allow them to have that. The -- so when we're looking at our Delaware position, Dominic mentioned that we've tested now 11 of the 12 layers in the stack in the areas that we're in, and we know that across that state line area, where we are, you've got a full stack. As you move around, different parts of the stack become -- disappear or become more gassy or become less productive. So understanding that variability is really critical. And before you commit to development plans, our philosophy just like it was in the Eagle Ford and the Bakken is understand the rocks, understand how best to develop those rocks and then start to implement a development plan. And so that underlying variability we point out is a big part of that.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And the other piece I would add to that is the growth rate in production is an output, it's not an input. So we're not trying to hit a certain growth target or growth rate. We're trying to optimize the development, and it's purely an output, making sure that we optimize on returns on capital. That's the driver.

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

That's helpful. And then as you did the -- you opened up with all the macro planning that you had been doing. I'm just curious, as you look at the U.S. unconventionals on a macro level, how did you see that playing out during your time -- your planning horizon? When does it peak? Does it peak? Yes, I'm just curious on what you guys see there.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

It varies across the scenarios. Frankly, there are some scenarios, let's put political risk to one side in the Lower 48 for a minute. There are some scenarios where the Permian peaks in five years. There are some where it's still growing modestly 15 years from now. It's all dependent upon really mostly how the cost of supply evolves over time and for the oil prices over time. And then they're all sort of intertwined n the scenarios that we look at. So that may not be a very interesting answer, but it has the advantage of being true. It's pretty uncertain as to exactly when these will -- when the Permian will peak and there are a lot of parameters that will influence that.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And that's why our scenario monitoring process is so important to us. As we look out, we try to look out two or three years to see the main drivers that are influencing that range of outcomes so we have an informed view about what's going to happen over the next two to three years as we put our plans in place over those discrete periods of time.

Doug Terreson ***Evercore ISI Institutional Equities, Research Division - Senior MD & Head of Energy Research***

Douglas Terreson, Evercore ISI. So you guys have outlined a pretty competitive business model and value proposition today and I had a couple of questions about that. First, it looks like your incremental returns on capital are kind of mid- to upper teens, which would be really good. So first of all, is that correct? And then second, can you provide a little bit more specificity on the sources of those gains, any particular areas that you're really enthusiastic about that you want to comment on?

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Sure. It's really broadly across the portfolio but Matt can talk a little bit about the specifics, geographically.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

So most of those increases in earnings are coming from Lower 48 and ACE, those two regions because as Bill showed you, APME is a fantastic region throwing off a bunch of prospects. There's not a huge amount of investment going in there to change the underlying returns characteristics. Those returns are great already, but they are not growing. It's really coming from ACE and Lower 48. And it's coming from all areas that Dominic and Michael outlined there. If you think about it from a returns perspective, so the average cost of supply of what we're developing is $30 a barrel. If the oil price is $50 a barrel on the reference case that we have, then, yes, that will be high-teens returns, in some cases, higher than that. So it's in the Lower 48, it's in Canada, it's in Alaska. I mean that's the -- and Norway. I mean it's across the whole portfolio. This is one of the beauties of having a consistent investment decision criteria because cost of supply levels the playing field for everybody. It takes time, value, money in account. It takes the split between oil and gas and NGLs in account. It takes transportation cost, it takes fiscal regimes, it creates a level playing field. And you can be pretty confident that if you invest in a portfolio that has an average cost of supply of $30, less than $30 in our case, you're going to be generating some pretty good returns if the oil price is averaging $50.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And that's been a deliberate effort of ours over the last three to four years, to get the portfolio in this shape, to drive the cost of supply down across all our investments. And so now the intramural sort of knife fighting that goes on during budget time, everybody is trying to drive their cost of supply down so they can get a portion of the capital that we're willing to commit. And we're going to be very constrained in the capital that we're willing to commit because we want to generate free cash flow, pay the dividend, pay our returns back to shareholders and keep some cash on hand for downturn protection.

Doug Terreson ***Evercore ISI Institutional Equities, Research Division - Senior MD & Head of Energy Research***

Okay, good. And then also Ryan, on corporate governance, it sounds like use of S&P 500 as a pure comparative risk for executive pay, which is the primary approach in the non-energy cyclical areas. The other three is being implemented at the company. And so my question is, is this change driven by the confidence in today's plan? Your belief that you guys can compete for capital with the other cyclical sectors? Or is there a different message here?

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

No, absolutely, Doug. It's the other three cyclical sectors. We deliberately put the S&P 500 on many of the charts that you saw today -- some in Matt's section and some in Don's section. So we recognize that -- and it's back to that slide that I showed, we're 4% of the overall market today, having drifted down from 12% just four, five, six years ago. And for us to bring investors back in, we've got to compete against those other cyclical markets. So we've got to have a free cash flow generation. We got to show improving returns. We've got to get money back to the shareholders.

And then we have to have a portfolio that allows you to grow at a capital intensity that's not so significant that you're consuming all your cash flow. And then on top of it, the balance sheet. We've learned you've got to have a strong balance sheet because the changes and fluctuations and the volatility of this market, you just can't predict. We just -- no one can predict. So you've got to be able to have that resilience to the downside and still keep your capital program going and keep your money going back to the shareholder. And that's what we're committed to do.

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

Ryan Todd at Simmons Energy. Maybe one, first of all, on the resource base. You guys, if you look at what you're able to do year-on-year in terms of the cost of supply numbers, you migrated a pretty significant amount of resource from the -- down into the sub-$30 a barrel bucket. If we think about -- is that -- from a primary driver point of view, is that primarily driven by cost reductions and efficiency gains? And if we think about looking forward you've got 22 billion barrels of resource that isn't under the $40 cut right now. How do you think about the potential to migrate some of that into the bucket, and maybe what are some of the most interesting opportunities to do that?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

That conversion, as we call it, from a higher cost of supply to a developable cost of supply, there's been a whole host of reasons that have done that. Certainly, there have been some cost reductions and capital reductions, tightening our belt, working -- there's been a huge amount of technology that's been part of the -- of that change as well over time. The -- whether it's new completion designs in the Lower 48. There's been a bunch of sort of complete rethinking going on across the company. Like the -- Michael talked about the developments in Norway, that were not competitive because we were going to do them the traditional way, manned wellhead platforms and those sorts of thing. So it's been a combination of a whole host of different actions across the company because of this focus that Ryan mentioned that cost of supply gives the organization. And they want to compete for capital. Engineers want to build things, but they know they have to be able to do that against a very competitive portfolio.

So then they get their thinking cap on and they may to come up with new technologies, they come up with better ideas. We make sure that those are all addressed consistently across the portfolio. Our chiefs go around and make sure that everything is very consistent, then we make our capital allocation decisions. So there's been a bunch of different things. Now is it reasonable to expect over the next three years we'll convert 5 billion barrels of resource? We did not expect to convert 5 billion over the last three years. They -- so I will be surprised if we can do that again exactly. (inaudible) But we will certainly be converting some, just exactly how much is hard to tell. We'll get people all over the company working on that right now to try and make that happen.

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

And maybe one follow-up on the Permian. We're probably more familiar with your Delaware position, a little bit less so with the Midland and the Northwest Shelf. It looks like from an activity point of view, is it fair to say that most of the activity in those areas is post-2025? And if that's the case, does it -- what reflects that, I guess, the pace there? Is it a view of relative competitiveness between the Midland and the Delaware currently? Is it an assumption of improved cost structures in the Northwest Shelf and Midland? Or how should we think about where that fits within the Permian portfolio?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

It's partly driven by where we are in the learning curve from -- across the different parts of the Permian where we're more advanced than our learning curve in the Delaware. And we have a very nice consolidated position in the Northwest Shelf. We have been testing some wells there. We're earlier in the life cycle there. And the same thing applies in the Midland. So we don't really did pay any significant -- I think the Permian was going to attract six rigs to get to plateau. The Delaware -- sorry, to get to a plateau that's probably around 300,000 from the Delaware. And then the Midland and the Northwest Shelf to attract maybe four rigs and gradually add up to another 100,000 barrels a day. So that's more a question of maturity in the life cycle of our understanding of them.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And the beauty of it is we've got a lot of offset operators. So there's some great data being developed. So Dominic described what we did in around the core position in the Delaware, 600-and-some wells drilled. We could interrogate the data and jump-start up to what people are finding to be a most effective stimulation, the most stacking and spacing. And then we can start to apply that to our particular acreage as well. And that's similar to what we're doing in the Yeso or the Northwest Shelf and the Midland Basin as well. We're not -- and again, we're not driven by the need for speed. We're not driven by trying to manage to a certain growth. We could accelerate a lot of things, grow a lot more, which I think will be the key differentiator in our value proposition we've thrown out today. A lot of people don't believe that. A lot of people believe you've got to ramp the growth, spend every big amount of capital you can and you'll get paid for that growth. We don't believe that's the right formula to win in this environment. And we'll see. We'll see how this plays out over the next few years.

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

Bob Brackett at Bernstein here. A question on the scenario planning process. We spent a lot of time talking about the $50 WTI base case and sort of the bumpers around that. Can you talk about the embedded differentials in that analysis, and I'm particularly curious about your long-term view of natural gas, both Henry Hub and maybe LNG pricing.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

So the differentials, I'll answer that one. We basically said that wherever the differentials were a few months ago when we put the plan together, so they're pretty much consistent with the current differentials. The Henry Hub price that we used was $2.50 real. So that's what the cost of supply is calculated based on and the cash flow projections. In terms of LNG prices, it's our view in our base case anyway that long-term LNG prices will probably be set by Henry Hub prices and the cost of liquefaction, transportation, regasification. So that's the basis upon which we think about long-term LNG prices.

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

A follow-on would be around Harpoon. What size would you need to have an economically viable development out at Harpoon? And what sort of size are you chasing?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

We tend not to jinx our exploration prospects by putting a range of resource out there before we drill them. We have a range of resource, but I'm not going to share that because it's never a good thing to do that. We -- needless to say, as Michael said, the same seismic signature as Willow and Narwhal. It looks like there could be the potential for more than one stack of it, the way that it sets up on the seismic imaging. So it could be quite a substantial resource there. Now it could be gas, and it could be water. It's almost certainly reservoir because we're pretty sure that's what the seismic signature is telling us. So we don't want to count our chickens before -- whatever that saying is. The -- so -- but the -- it could be quite a substantial resource. It doesn't have to be huge for it to be tied back to the Willow Hub.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Yes, and that's why minimum economic size is a little bit different, Bob, when you think about it, if it's a drillsite development that can tie back to the Willow Hub, it's a lot different than if it needs to be a stand-alone processing facility. What we'd like is it to be big enough to be a stand-alone processing facility, obviously, because then a lot more resource in a 30-mile radius around that becomes much more economic and competitive on a cost of supply basis. So it's a little bit hard to say exactly what a minimum size to develop might look like because it depends.

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

Scott Hanold with RBC. Can I go back to the discussion on the conversion cost? On Page 18, you do a really good job of breaking down the various components of that -- of your cost of supply. Can you talk about the conversion cost to get it there? If you were to look at it in all-in, full-cycle for your portfolio, where do you think that is? And where does it go going forward on some new opportunities?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

I'm glad you asked that question actually, because I don't think I covered it clearly enough in retrospect. So we've consistently been talking about our development resource base of less than $40 a barrel cost of supply. Sometimes when we've talked to investors about that, they'll say, "Well, that's all well and good, but that's a point-forward thing," and we've been perfectly clear. Yes, a point-forward thing because it's a decision-making tool. The -- but we've been asked, "Well, do you consider the full cycle?" Well, of course, we do. Yes. The -- and that's the context of the conversion cost or the funding cost or the acquisition cost is we have to be taking that view of the portfolio as a whole because we know that there are costs associated with getting resource ready for development, whichever those may be, the different sources of that.

And that's why the $50 a barrel thing is a really important thing to bear in mind because we want to be absolutely confident that our reference price, regardless of what we invest in, including the work that's going on in the background on new resources that are coming in, that we can deliver returns above our cost of capital at that reference price. So I mean I wouldn't quantify -- some of these conversion costs are incredibly low, really very low, $1. They -- but they -- some of them are a bit longer because they take a bit more time to develop. But that distinction between the $40 a barrel to attract development money, get in the plan and the fact that we recognize that there are costs associated with that, full-cycle costs, we need to be cognizant of that element of it, that's really what we're trying to convey with that distinction between $40 and $50.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Yes, and its quite variable. If you think about the commercial advantage that we created at Surmont by investing a little bit of money to make that plant a dual-diluent plant. All of a sudden, that decreased the cost of supply of the things that we're developing at Surmont because it increased the netback, obviously, and made more resource now economic at a $50 or even on a full go-forward basis at $40. So there's many different elements to it. It's technical. It's technology, it's commercial. We're trying to tag every bit of that waterfall that Matt showed in order to keep driving the cost of supply down on a full-cycle and a point-forward basis.

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

And as a follow-up, can you talk about asset dispositions. Obviously, it can be a sensitive subject when you look at your existing portfolio, but you've done a fantastic job over the last several years of really pruning it down to your best stuff. When you look at your portfolio right now, can you just discuss, are there opportunities to further pare that down without being specific because I understand the sensitivity.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Yes, we don't see any significant or large -- other than what we've outlined here today, we don't see any significant or large kinds of things that we're doing. But with that said, we're constantly pruning the portfolio. We're constantly looking for opportunities when stuff doesn't compete for capital, the exploitation doesn't compete for capital, we've demonstrated that we're willing to try to monetize that in other areas. If other people find that those investments are competitive, we're willing to make those kinds of portfolio moves. It's been a very deliberate effort over -- really since the spin in 2012, it's been a very deliberate effort to get to the kind of portfolio that we're showing you here today.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Yes, just to be absolutely crystal clear, the only larger significant further disposition that we have premised in the plan is the dilution in Alaska. There could be small ones here and there, but in terms of large strategic significant reshaping of the portfolio, as Ryan said, that's our strategic thrust that we've had. For the most part, it's now behind us. We have a portfolio that we like now.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

We probably have time for just two more here, so Josh?

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

Josh Silverstein from Wolfe Research. Don, you laid out a stress case before where it went down to $40, but you didn't really change your activity levels, it seemed like the buyback was coming down. So I just wanted to see if that was the case and where in a downside scenario capital could be adjusted from an activity standpoint?

Don Wallette ***ConocoPhillips Company - Executive VP & CFO***

Yes. Thanks for the question because I wanted to be sure that we were crystal clear on what was happening during that stress test. So during that three-year period where prices fell to $40 and stayed there, we didn't change our capital program at all from the base plan. We didn't change our distributions at all. So we were continuing buybacks fully $3 billion a year through each of those three years. And that's the main point we were making is that we think there's a lot of value in that continuity in our balance sheet. Our financial strength gives us that ability. And also to address what some people think we've got a high level of cash on the balance sheet. And I think, well, no, I don't think we have a high level of cash on the balance sheet. I think we have an appropriate level of cash on the balance sheet, given the strategic intent for each of those layers of cash.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

And now with the capital program. I mean, if we saw $40 for an extended period of time, three years in the stress test, we would expect some deflation, we'd expect the scope that we're executing to probably cost a bit less. The important part is we want to execute the scope. We want to execute that scope through the cycles.

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

Got it. And just a follow-up. You mentioned, at least from the Eagle Ford presentation, about the parent-child impact. In the Lower 48, are you guys assuming that you're drilling the same well 10 years from now that you are today? Or are there changes because of the degradation of that parent-child impact?

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

The degradation effect is -- we believe we have that pretty well calibrated. And as Dominic laid out, the core development approach that we have, that's already baked into the plan. We do not expect it to get worse over time because of the nature of how we're laying the plan out. And Dominic also showed there's quite a bit of potential for it to get better with these -- the -- what we sometimes call defensive fracks where we're refracking defensive refracks, refracking an older-vintage well at the same time as refracking the child well. So there's potential for it to become less as we think we've built in a more reasonable expectation of what it should be absent new technology to help us mitigate that.

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

So the last one?

Muhammed Ghulam ***Raymond James & Associates, Inc., Research Division - Senior Research Associate***

Muhammed Ghulam from Raymond James. So we've seen a lot of your peers put a significant amount of capital behind renewables and sustainability. Can you guys talk about how you think of such investments?

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Yes. So I think, first and foremost, as Matt laid out in our scenario and as we think about the long-term future, we think hydrocarbons and fossil fuels will be a significant part of that fuel mix for quite some time, well in the 2050s and beyond. So our focus today is just being on the best lowest-cost E&P company that we can be. We are not making investments today in any renewables, wind or solar, but that doesn't mean we rule that out down the road. Again, we look at our scenarios, we look at our scenario monitoring process, we think about where the company is at today. But our job is to be an E&P company that's the best we can possibly be. But we don't rule it out in the future. But today, we're not making any investments in those channels.

Muhammed Ghulam ***Raymond James & Associates, Inc., Research Division - Senior Research Associate***

Okay, understood. Flaring in the Permian remains a significant issue. Can you guys discuss the latest on that and the outlook for flaring and takeaway for your assets there?

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

Yes, I can let Matt get into the specifics. But yes, we recognize that flaring gas in the Permian is not a good thing for the industry. So we are trying to be a partner -- we're not routinely flaring in the Permian, and we keep that to a very low percentage of the gas production that we're producing today, but that's not ubiquitous across the basin. And we realize industry has got an issue to deal with. We're addressing that, as Dominic said, through a lot of our LDAR methane and fugitive emissions and keeping our flaring non-routine flaring now, going down to zero.

Matt Fox ***ConocoPhillips Company - Executive VP & COO***

Yes. If you look at state data that's published here, you'll see that we are not a source of significant flaring in the Permian at all. We had a very, very high capture level, high 90%.

Muhammed Ghulam ***Raymond James & Associates, Inc., Research Division - Senior Research Associate***

(inaudible)

Don Wallette ***ConocoPhillips Company - Executive VP & CFO***

That is because we don't have takeaway issues in the Permian. As Dominic mentioned, we're one of the top gas marketers in the United States. So we have lots of evacuation routes out of the Permian. In fact, we move a lot of third-party gas out of the Permian. So...

Ryan Lance ***ConocoPhillips Company - Chairman & CEO***

All right. Well, thank you all. Thank you very much. That concludes our meeting. For those in the room, they can join us. Me and my leadership team will be in the Forest Room for lunch. Please come and join us if you can go do that. So thank you very much. That concludes the meeting. Let's do this again in 10 years.