3Q19 Earnings Conference Call Edited Transcript

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This transcript has been edited by Chevron Corporation. It is generally consistent with the original conference call transcript. For a replay of the Investor Conference Call, please listen to the webcast presentation posted on chevron.com under the headings "Investors," "Events & Presentations."

Transcript

Operator:

Good morning. My name is Jonathan, and I will be your conference facilitator today.

Welcome to Chevron's Third Quarter 2019 Earnings Conference Call. As a reminder, this conference call is being recorded. I will now turn the conference call over to the General Manager of Investor Relations of Chevron Corporation, Mr. Wayne Borduin. Please go ahead.

Wayne Borduin (GM Investor Relations, Chevron Corporation):
Thank you, Jonathan. Welcome to Chevron's third quarter earnings call and webcast. On the call with me today are Jay Johnson, EVP, Upstream, and Pierre Breber, CFO. We'll refer to the slides that are available on Chevron's website.

Before we get started, please be reminded that this presentation contains estimates, projections and other forward-looking statements. Please review the cautionary statement and important information for investors and stockholders on Slide 2.

Turning to Slide 3… and Pierre.

Pierre Breber (Chief Financial Officer, Chevron Corporation):
Thanks Wayne…we had another quarter of strong operational and financial performance.

First, an overview of our financial results. Earnings were $2.6 billion, or $1.36 per share.

The quarter's results included a $430 million special item tax accrual associated with a cash repatriation in the fourth quarter. Foreign exchange gains for the quarter were $74 million. Excluding special items and FX gains, earnings were $2.9 billion, or $1.55 per share. A reconciliation of non-GAAP measures can be found in the appendix to this presentation.

Cash flow from operations was $7.8 billion. We also maintained a strong balance sheet with a low debt ratio.

Importantly, our strong cash flow allowed us to continue to deliver significant cash to our shareholders. During the quarter, we paid over $2 billion in dividends and repurchased $1.25 billion of shares, in-line with our annual share repurchase run-rate guidance of $5 billion. Year-to-date, we've returned approximately $9.5 billion in dividends and share repurchases.

Year-to-date organic capex was $14.5 billion, slightly below our ratable budget of $15 billion. Total capex, which includes inorganic transactions that are unbudgeted, totaled $15 billion. We are maintaining a firm commitment to capital discipline to improve returns on capital. Turning to slide 4….

Third quarter cash flow was strong – down from the prior quarter due to lower Brent prices and the absence of the termination fee received from Anadarko.

On a year-to-date basis, cash flow from operations of nearly $22 billion funded all four of our financial priorities. With nearly $12 billion in free cash flow, we currently have an annualized yield of about 7 percent, highlighting our ability to generate strong free cash flow in a lower oil price environment. Through three quarters, the company's cash flow dividend break-even price, excluding working capital, is in the low 50's [dollars] Brent.

Asset sales proceeds add to our positive cash flow and further lower the break even while high-grading our portfolio. Since the beginning of 2018, asset sale proceeds have totaled $3 billion, and by year end after the expected closing of the sale of our U.K North Sea assets, we will be near the low end of our $5 to $10 billion guidance range with one year to go.

Turning to slide 5….

Third quarter 2019 earnings of $2.6 billion decreased about $1.5 billion versus prior year. Excluding special items and FX, upstream earnings declined primarily due to lower crude and natural gas prices partially offset by higher liftings.

Downstream earnings also were down primarily due to higher turnaround and maintenance costs, lower volumes driven by the Southern Africa divestment, and lower chemicals margins. The variance in the "Other" segment primarily reflects lower corporate charges versus last year.

Turning to Slide 6…

Compared to the second quarter, third quarter earnings decreased by about $1.7 billion dollars. Excluding special items and FX, upstream results were lower primarily due to a 10 percent decrease in Brent prices since the second quarter.

Downstream earnings, excluding FX, improved due to stronger refining and marketing margins, partly offset by lower chemical margins and the impacts of planned turnarounds. The variance in the "Other" segment primarily reflects lower corporate charges and tax items.

I'll now pass it to Jay…

Jay Johnson (EVP, Upstream, Chevron Corporation):

Thanks, Pierre.

On slide 7… third quarter oil equivalent production increased three percent compared to a year ago, with higher shale and tight production in the Permian, as well as higher production from major capital projects following the ramp-ups at Big Foot and Hebron. This growth was partly offset by unplanned downtime at Hibernia, asset sales, and the impact of Hurricane Barry in the Gulf of Mexico.

Turning to Slide 8…

Third quarter production was strong at more than three million barrels a day for the fourth consecutive quarter despite the impact of planned turnarounds and asset sales. Year-to-date production, excluding asset sales, is about five percent higher than 2018, consistent with our earlier guidance of four to seven percent growth, as shown by the middle bar. Looking forward to the fourth quarter, we expect production growth to be primarily driven by our shale and tight assets, as well as the continued ramp-up of Hebron.

Turning to Slide 9, I'll provide an update on the TCO project.

In the third quarter, we completed a detailed cost and schedule review of the Future Growth and Wellhead Pressure Management Project in Kazakhstan. As a result, the cost estimate for the project has been updated to $45.2 billion, with an additional $1.3 billion in contingency. The expected start-up of FGP has shifted to mid-2023 and will now follow WPMP, which remains on schedule for start-up in late 2022. The updated estimate has been submitted by TCO for shareholder approval.   Overall, the increase in total cost, including contingency, is about 25%.

The waterfall shows the key drivers of the updated estimate. As discussed previously, higher engineering costs and engineering's impact on fabrication consumed about two thirds of the original contingency.

Additional construction costs represent the largest category of the revised estimate. More than half of the increase in construction cost is due to higher quantities than originally estimated – including significant increases for electrical and instrumentation, which was one of the last scopes of the engineering work to be completed. The balance is primarily driven by higher unit construction rates, due to higher market rates and more complex work than originally anticipated. Finally, the Schedule and Other category is primarily driven by the FGP schedule delay, and increased costs for operational readiness and the owner's team.

Despite the increased project cost, TCO remains a world-class asset that's expected to generate strong cashflow for many years.

Turning to Slide 10.

Beginning in 2020, we expect spending to ramp-down as we complete the project.

The project is approximately 70% complete. Detailed engineering and procurement are essentially complete, mitigating the risk of further impact on fabrication or construction. Work at three of the four fabrication yards is finished. The logistics system is working well, and the 2019 sealift has successfully concluded. Modules are being delivered, re-stacked, and set on foundations as planned. Drilling is ahead of schedule with 40 of the 55 wells drilled and completed.

The lower chart on the slide shows the completed and remaining capital spend. Most of the remaining scope now resides with construction and start-up activities. Given the work completed, including two full years of on-site construction experience, we believe we're on-track to deliver the project in line with the updated estimate.

Importantly, we're not changing Chevron's capital guidance. Our 2020 capital, to be announced in December, will be in the range of $18 to $20 billion, and we're reaffirming our capital guidance of $19 to $22 billion for 2021 through 2023. We remain committed to capital discipline and delivering leading returns for our shareholders.

Slide 11 highlights some recent commercial developments in our upstream business.

First, we recently announced a farm-in agreement to take a 40% working interest in three Mexican blocks in the deepwater Gulf of Mexico. We also recently participated in Brazil's 16th Bid Round and were awarded a 35 to 40% working interest in two operated and three non-operated blocks. We're excited about these additions to our exploration portfolio.

Last week, we signed an agreement to sell the company which holds our interest in the Malampaya gas field in the Philippines. We are expecting the transaction to close in the first half of 2020.

Now back to Pierre.

Pierre Breber:

Thanks, Jay. Turning to slide 12….

This quarter, there were a number of highlights related to lowering the carbon intensity of our operations.

Earlier this month, we announced two new greenhouse gas reduction goals. The new goals are aimed at reducing our oil emission intensity by 5 – 10 percent and our gas emission intensity by 2 – 5 percent from 2016 to 2023. These are in addition to the targets we set at the beginning of the year to reduce our flaring intensity and methane emissions over the same time period.

In Australia, we started up the Gorgon CO2 Injection Project in early August and are in the process of ramping it up to full capacity. Once fully operational, this will be one of the world's largest carbon sequestration projects and is expected to reduce Gorgon's greenhouse gas emissions by about 40 percent over the life of the project.

Lastly, construction is underway on a new 29 MW solar farm which will supply electricity to Chevron's Lost Hills field in California.

Now … looking ahead.

In Upstream, we expect full year 2019 production growth to be in the middle of the 4 to 7 percent range, excluding 2019 asset sales. Asset sales, primarily in Denmark and Brazil, are forecasted to have a full year impact near 30 MBOED.

Planned turnarounds, primarily in Gorgon and Nigeria, will be lower than third quarter but are expected to impact production in the fourth quarter by more than 70 MBOED.

As Jay mentioned earlier, we have acquired new exploration acreage in Brazil that is expected to add about $120 million in inorganic C&E, which is unbudgeted.

Full year TCO co-lending is expected to be below the full-year guidance of $2 billion as it is dependent primarily on the fourth quarter distribution decision.

In Downstream, we expect "high" refinery turnaround activity. This includes a refinery-wide turnaround at SPRC in Thailand, which occurs once every five years.

In the fourth quarter, we expect to make the $430 million tax payment related to the cash repatriation and to repurchase shares of $1.25 billion.

With that I will hand the call back over to Wayne.

Wayne Borduin:
Thanks, Pierre. That concludes our prepared remarks. We're now ready to take your questions. Jonathan, please open the lines.

Q&A

Operator: Our first question comes from the line of Jason Gammel from Jefferies.

Jason Gammel - Jefferies
First question related to the updated Tengiz budget. Given that a lot of the spending is already behind you, do you anticipate that this is going to have any significant effects on the co-lending that you'll be making to the venture in the coming years? And I'll just ask my second question now. The U.S. downstream earnings were pretty robust this quarter relative to what I would have expected, just given a heavy turnaround schedule. Is it just the margin environment that was helping out? Or is there anything else that's happening in downstream that is maybe more ratable?

Pierre Breber
Thanks, Jason. This is Pierre. On co-lending, we'll provide guidance for 2020 next quarter as we have in prior years. As you know, co-lending depends on three primary factors: the level of the capital spend, oil prices/the macro environment, and any dividends. I guided in the fourth quarter that we expect the full year for 2019 to be lower than our $2 billion, but it will vary depending on the fourth quarter dividend decision that TCO makes. So, if the dividend is higher, the co-lending would be higher. If it's lower, the co-lending would be lower. So, if you go back to how this cost increase impacts co-lending, you really must look at it as overall cash flow. So clearly, if you hold prices and dividends constant, higher capital costs will result in higher co-lending. But that does not translate to lower Chevron cash because we're going to offset the increases in TCO elsewhere in our capital program. And so, if you remember, TCO capital spend is noncash and co-lending turns part of it into cash because we think it's the most economic way to finance our share of the TCO spending. But again, we're going to have offsets elsewhere in our capital program, which will be cash CapEx, and that will help offset that higher co-lend.

For downstream' s quarterly results, there's nothing that isn't inherent in the underlying margins that I can really point to. Distillate margins have popped up a little bit, and we tend to have more production in that space. You're seeing some of the effects of IMO that are rolling through the system. West Coast margins had some strength at times in the quarter. But I would attribute the third quarter performance largely to how we operated in the underlying margin environment.

Operator: Our next question comes from the line of Phil Gresh from JPMorgan.

Phil Gresh (JPMorgan):
First question, just coming back to the idea that the Tengiz CapEx increase will not affect the overall capital spending plan. Are we just talking here about the fact that perhaps you're at low end of CapEx ranges and now you move to high end of CapEx ranges? Or how do you calibrate being able to offset $4 billion to $5 billion of incremental spending to Chevron within the budget? Is it activity elsewhere? Or is it just within ranges here we're talking about?

Jay Johnson
There's a couple of different places that we look to. First, TCO itself and the base capital spend has offset, and will continue to offset, some of the increase in the FGP spend. Beyond that, we have a much more flexible capital program now with a lot of short-cycle activity, and we're able to pace and adjust that program to fit within the investment levels that we set, and particularly as it relates to gas-related investments are opportunities for us in this current environment to scale back some of that as appropriate. And those are things we may have done anyway. The final thing is the capital efficiency that we're driving throughout the business. Our base business performance has been very strong. We have digital initiatives, trying to make our capital spend more effective. Across the board people are figuring out ways to do more with less. I'll give you a good example which was in Bangladesh, where instead of making a major capital project to add some additional compression, the team was able to look at recompleting wells, adding perforations, and

debottlenecking existing facilities, which extended the production plateau and alleviated the need for incremental capital spend on another project. So, it's these types of spending that we are constantly working through as we allocate our capital each year. We're going to remain capital disciplined. We're going to stay within the ranges that we've given you, and we're going to look to do it while we stay focused on delivering the value and returns which are driving our decisions.

Pierre Breber
If I can just build off Jay's answer there. Just to be very specific. No, we do not intend to go from the low end to the high end of the range. We intend to find offsets through the way that Jay has talked about. We have a range because we're giving guidance out to 2023. It is a cyclical business. Oil prices can change, COGS can change. We have short-cycle capital that we can flex up or down. Our intent is to offset [the capital] increase elsewhere.

Philip Gresh
Thank you for that color. And then, just a follow-up would be for Jay. I'm just trying to rewind here back to a year or so ago, there were some fears that things were getting a bit behind in Tengiz and then back at the Analyst Day, the tone sounded much better that things are back on track. And now that we have a 25% increase, which is fairly sizable. So, I'm just hoping you could provide a little bit more color about how these things have progressed to the point that we have this kind of increase?

Jay Johnson
I think what's changed fundamentally is we completed a very detailed cost and schedule review in the third quarter. As we looked at it, there were a couple of key elements. We've talked in the past about the overall engineering program, the cost of that program and the impact the engineering has had on fabrication and construction. And you can see those in the first –two bars on slide 9. That really reflects that accelerated consumption of contingency that we've talked about in the past. What was, frankly, a surprise was the increasing quantities that we're seeing coming out of the late stages of engineering, particularly related to things like the electrical and instrumentation controls, fire and gas, some of the late changes in how we're going to do the backfill and quantities associated with it. Those drove a much higher construction costs than we had anticipated. If you look at the third bar, you see that represented.

The other big surprise was having to delay the start-up of FGP by a year. This is really driven fundamentally by an assumption change. We had planned to integrate modules. Our estimate was based on the integration of the modules in FGP, each one taking about 12-months from the time it was placed on its foundation until it's fully integrated. While we're seeing completed modules come from the fabrication yard and we've gotten a year of ME&I (mechanical, electrical & instrumentation) experience, our view has changed and we are now using 14-months as our planning basis, and that's pushed that schedule time out. So, the growth in quantities and the longer schedule have really been the surprises that we didn't anticipate previously.

Operator: Our next question comes from the line of Neil Mehta from Goldman Sachs.

Neil Mehta (Goldman Sachs)
On the Permian and the glide path here. You continue to trend above your target levels. Can you just talk, Jay with some detail about how the plan is progressing in the Permian and any comments that you would have on sort of this upcoming U.S. election? And any impacts the way you think about prosecuting your acreage?

Jay Johnson
I'll start with just the performance in the Permian. Our view, as you know, has been to be very disciplined and focused on returns and efficiency. We have seen continued performance improvement in our drilling. Our completions have

remained very strong throughout. We're watching every segment of the value chain from the actual land acquisition to fill in some of the checker boards which allows the longer laterals right through the drilling efficiency, into the completions, the facilities and on production. Then working with our Marketing and Transportation group to ensure that we're getting the highest realizations we can for the products that we're producing. We've are doing very well with our production profile. We're pleased with the performance that we're seeing, but we're always driving for better performance.

In terms of the upcoming election, look, hydraulic fracturing has been done for millions of wells, not only in the U.S. but around the world. It's done safely. It's done effectively. We learn more about it all the time. And it's really unlocked a huge economic benefit for the country, as well as for the companies involved. It's also unlocked some environmental benefits in terms of the proliferation of gas, which isn't always to our benefit from a profit standpoint, but it's a great fuel for the U.S. If you look at it from our company standpoint, we have less than about 10% of our Permian unconventional acreage that is on federal land, and all of that is in New Mexico. So, from a relative standpoint, while we would not like to see any kind of restrictions on hydraulic fracturing -- that's the context for our company.

Neil Mehta
Then the follow-up here is related to Brazil. There's the upcoming transfer of rights auction, and you called out some of your increased exploration acreage there. Can you provide some context in terms of the way that Chevron thinks about Brazil and how aggressive it sees itself being there over the next couple of years?

Jay Johnson
Well, we've talked before that we are very happy with our existing resource base. We've been doing a lot of portfolio work, as you know, over the last several years to really clean up our portfolio. Part of that has been a reload of our exploration strategy. But because we're happy with our resource base, we have primarily focused on reloading in the exploration space, because we're looking for resource additions out in the future. We also want to manage our capital over the period of time. That's what you've seen us do in Brazil. We are interested in Brazil because we see the pre-salt as a prolific hydrocarbon basin. It's a good place to be to increase the probability of success on exploration, and we'll stay focused on that. We have a couple of wells coming up next year which will be good wells for us. We're looking forward to seeing those results. But we'll continue to stay focused primarily on exploration as we look forward.

Operator: Our next question comes from the line of Paul Cheng from Scotiabank.

Paul Cheng (Scotiabank)
Jay, don't want to beat the dead horse on Tengiz, but what have you learned from Tengiz to further finetune your development and project execution process? Clearly there's something that was not working in order for us that to have that at this stage, to have the delay for a year and also that for 25% increase. So, what have we learned?

Jay Johnson
Well, Paul, it's a good question. We ask yourself all this time -- how can we do better. Clearly, this is a disappointment. I'm very disappointed because we have taken all the lessons learned from the past and try to make sure we're building those into each project as we go forward. When we think about what's gone well. There have been a lot of dimensions to this, particularly the execution work is going very well. I'm happy with the way the fabrication work has gone in the yards. The modules are coming out very complete and dimensionally accurate and we set them on their foundations, everything is lining up. The logistics system has been flawless. The performance is exactly how we had planned, and it's delivering modules to the site very effectively, and we've been able to complete the sealift for 2019. So, we're happy on all those fronts.

The schedule delay is a disappointment, and that has to do a lot with the quantity growth we saw from engineering. And as we've said, we've been unhappy with the overall engineering performance on this project. Not only the engineering costs themselves, but the impact it's had on fabrication and construction. We need to do better in this area. And it's an area that we're going to continue to learn our lessons from and build it forward. We don't have any other very large mega-projects like this, that are land-based anywhere in the world at the current time. So, we've got time to take these lessons learned and really think about how we approach this differently in the future.

Our commitment remains on capital discipline. Our commitment remains to execute this project to the best of our ability. When you look at the improvements taking place on the ground in Tengiz, in 2018, we talked about productivity that we needed to improve, and we saw a 40% to 50% improvement in the productivity across the site. In 2019, we've seen another 30% to 40% improvement in productivity. We're seeing great improvements with the production and construction management systems. We're going to continue to stay focused on productivity, on completing work, moving it to mechanical completion and then getting it through systems completion to start-up.

Pierre Breber
Yes. And if I could just build off of Jay's answer, Paul. Just to put this in an enterprise perspective, the additional depreciation after tax to Chevron is less than $0.20 per share or less than the cash flow impact of a dollar change in oil prices. So as Jay said, we own this, and we need to do better. And trust me, we're fighting for every dollar. But I did want to put in perspective what this means for a company like Chevron.

Paul Cheng
Sure, I understand. But I think, Jay, when you're saying that you're unhappy about the engineering on this. So, is it an internal issue? Or just an external issue with the contractor that you guys use?
How do you -- how are you really going to be able to mitigate it in the future? I mean, that -- what -- I mean, you say you learned from that, but exactly what have we learned? And what is the change will be?

Jay Johnson
From an engineering standpoint, Paul, I think we have a couple of things. One is we are doing more to bring the early engineering back in-house and do more focused design development with our own capabilities. We're trying to minimize the amount of variation that we see in terms of each project team's decisions that they make around engineering. I think that's a key part of it and I think looking at the total project in the context of the environment its going to be built in is also important. I do think there are also opportunities for the industry to improve on engineering. I don't think this is necessarily isolated to our company. So, there's work to be done as we really understand how to better define and prosecute the engineering programs that are necessary for these projects.

Pierre Breber
We don't have projects like this in our queue. If you look at our capital program, a lot of base business capital, shale and tight capital, we are going to have some major capital projects but the ones that are coming up are deepwater projects, and they're very different than these. A lot of the spending is in drilling and completion, where we're very good on the facility side, it tends to be standard designs in fabrication yards. As Jay said, it's not land-based projects in remote locations, and we have a better track record in those ones. So again, we need to do better. We're learning from it. From an enterprise perspective, the portfolio, the investments that are at least in front of us are hitting a different place than where this project has been.

Paul Cheng
My final question, Tengiz, even before the cost increase, the full project return on capital -- the full cycle internal rate of return is actually pretty low. And with this, that of course, is much lower. But the cash flow will be great once that they come onstream. So, which is a more important factor when you guys determine whether you want to go with a certain

project? Is it the internal rate of return? Or is the cash flow and the sustainability of that cash flow? So, I'm trying to understand that the decision-making process?

Pierre Breber
You've heard Jay, Mike and me all talk about increasing returns on capital. So, we are focused on the return on investment. We are looking at it. And once you have a cost increase, I think it's stating the obvious that, that dilutes the returns, and we're taking a lot of actions to offset that, both at Tengiz and across the rest of the portfolio. I tried to give, some financials that kind of characterize what the impact is on a company like Chevron, less than $0.20 per share. But we are looking fundamentally at returns on capital, but we also know cash is important. It helps pay the dividend and support the share buybacks.

Jay Johnson
I know your views on it have been the same for a long time, but this is an important project for Tengiz. It does lower the back pressure on all the wells and addresses the declining reservoir pressure that we see there. It provides excess gas handling, which will unlock oil production in our existing facilities as well as for FGP and it helps maintain reservoir pressure in the platform, which is an important aspect of the overall performance of Tengiz, not just the incremental performance. Also, we are looking at ways that this can be offset. One of the key milestones that was achieved was the decision to debottleneck the CPC pipeline. And so that's going to open up some additional export capacity, which will improve realizations and help boost returns and help mitigate and offset some of the increases that we're seeing on project cost.

Operator: Our next question comes from the line of Devin McDermott from Morgan Stanley.

Devin McDermott (Morgan Stanley)
I wanted to follow-up on some of the exploration discussion from earlier. You talked a little bit about Brazil, but you also highlighted in the release and slides, some additional blocks in the offshore Gulf of Mexico, and I think you've been fairly active in the U.S. Gulf of Mexico leasing as well. As we're going to step back and look at where you're seeing the most opportunity from here, can you talk a little bit more about that and the overall strategy here and the desire, if any, to diversified growth options away from shale and tide but I think you mentioned there were some larger capital projects offshore, potentially in the pipe? A little more color on that would be great.

Jay Johnson
Yes, thanks for the question. In addition to deepwater Brazil, we have been very interested in some of the deepwater in the Mexican areas of the Gulf of Mexico. This plays on a lot of the knowledge we already have in the U.S. sector of the Gulf of Mexico. We've recently farmed into some additional blocks and these complement nicely, some blocks we'd acquired in an earlier bid round.

One of our strategies has been to move out of more of the frontier, highly-speculative areas and really focus our exploration initiatives in the areas that we consider to be highly-prolific basins, and that really increases our probability of success. At the same time, we're doing that, we're trying to balance the amount of capital that what goes in early and really use the fact that some of this is only under 2D seismic or lightly explored to open up new opportunities for development.

In the U.S. Gulf of Mexico, we've been very active. And one of the key strategies in the U.S. Gulf is to focus a lot of our new blocks around existing infrastructure, and we're looking to push that envelope of how far we can tie back exploration opportunities or discoveries to existing infrastructure and avoid having to build brand-new greenfield. For example, you recently heard about the Essex discovery with another operator, that will tie back to tubular bells. It's very close. It brings new production in at very low capital cost and with a very short-cycle time. So those are kind of the low-cost, high-return subsea tiebacks that are being enabled and supported by our exploration strategy in the U.S. Gulf of Mexico. We're also talking about extending that reach through some of the new technology. We have used quite successfully the phase pit floor pumping at Jack and St. Malo and really proven that technology, and we've now finished the technical certification to move to multi-phase pumping and this can really extend that radius, of which we can pull production back to existing hosts that have ullage. So, it's entirely in line with our theme of exploring in prolific basins, but also utilizing existing infrastructure and getting more out of our existing facilities whenever possible.

Devin McDermott
M second is on some of the comments around incremental efficiencies you're realizing across the portfolio is one of the things you mentioned in response to the Tengiz's cost pressure. And Pierre, I think you mentioned it also as an area where we've seen success across the portfolio in your prepared remarks. So, I was hoping to get a bit more specifics on where within the portfolio you're seeing the capital efficiency improvements. And then also, to the extent you are cutting back capital in more gassy areas in response to the Tengiz's pressure? Any additional detail on where that is, in North America, gas elsewhere in the portfolio. Additional color would be helpful there as well.

Jay Johnson
The increased efficiencies, quite honestly, are happening across the board. All of our units are really focused on how to continue to drive better performance out of the investments we've made in the past. We've seen some great improvements. For example, in Angola, where they have developed new opportunities by using our existing installed base. We've seen very strong cash flow coming out of Angola, and there's been a lot of good cooperative work with the government of Angola to unlock many of the marginal reserves that can be tied back to our existing facilities. But it really is happening around the world.

In terms of the Gulf of Mexico, we've seen our unit development cost come down to where we're now targeting $16 to $20 a barrel for new facilities and projects like Anchor and Whale. The OpEx in the Gulf of Mexico and the deepwater has come down to just under $10 a barrel, which is a significant reduction from where we were in 2014. We're taking these lessons learned, we're sharing them across other areas in the company. It's one thing to share, it's another to adopt these best practices, but we're seeing great cooperation between our business units, and we're going to be really focused on doing that even more as we move forward. All of this isn't just in response to Tengiz. But rather, it's the context of Tengiz in this environment that's allowing us to do this, and I think do it quite efficiently.

In terms of the specifics on where in our capital program, we'll be making changes. That's not something that we'll discuss at this point in time, but we'll give more color on that potentially in December with our capital announcement and, of course, in the Security Analyst Meeting that we do early in the year each year.

Operator: Our next question comes from the line of Biraj Borkhataria from RBC.

Biraj Borkhataria (RBC)
Sorry, I have another one on Tengiz. Jay, you mentioned the significant productivity improvements in 2018, 2019, but taking that on board, that would suggest the CapEx increase was coming quite a long time ago. So I guess, just want to square that comment with the CapEx increase today and the timing of that. But taking a step back, you look at the last few years, and you've had your fair share of issues at some of these major projects. Pierre, you're signing off on these. I just wonder if these experiences make you think twice about embarking on these types of projects of this scale in the future? That would be my first question. I've got another follow-up.

Jay Johnson

The contracts at site at Tengiz and the construction are largely unit rates. We pay based on the quantities that are being installed. Productivity is important because it relates to the underlying schedule along with the ability to finish and execute the work in the allocated time frame and with the numbers of people we planned because there's a lot of indirects that come with having to add additional direct labor. So, while the unit rates have been in place, it's really the complexity that has increased on some of the manhours. We've talked in the past about the unit rate costs that were in our bids for the mechanical, electrical and instrumentation work. The surprise has been the increase in quantities because when you multiply the quantities times those rates, that's what's resulting in the higher cost and the shift in schedule. That's how I square that with what we've given you in the past and really what came out of the detailed cost and schedule review that we just completed.

Pierre Breber
We don't have other projects like FGP/WPMP in our queue. Kitimat is being worked, but it's not ready. What we have is a lot of base business capital, a lot of shale and tight capita, and hopefully, some deepwater projects here over time. I understand your question, it's theoretical. I'm not going to speculate about it. But as I look at our portfolio, right now, we don't have that choice. That said, we're going to be in the business a long time. We're going to learn from it. We have to do better, but we don't have any immediate capital decisions that are in this kind of large-scale, land-based construction project.

Biraj Borkhataria
Okay, understood. Just to follow-up, hopefully, an easier question, but the tax on repatriated cash. Are you expecting that to be a one-off? Or is it -- should we expect more of these in the future? Can you confirm whether that was cash tax or just a P&L charge?

Pierre Breber
We completed a global cash management review in the third quarter and decided to repatriate this cash, which was previously unremitted. Prior to completing this review, these earnings were expected to be invested outside the U.S., and that's why we didn't accrue for the state and for the withholding taxes. So, when we made the decision to repatriate it, that's when we accrue the tax. The cash tax payment will be in the fourth quarter, we accrued the P&L was in the third quarter. The actual cash movement will bring non-U.S. cash into the U.S. It will allow us to lower our cash balances and will lower our debt balances. We're doing it because it's the right economic decision. This is for prior earnings. We do not expect other types of repatriations of prior earnings like this. At the same time, there could be some current earnings that, of course, are repatriated, and that's in the normal course of business. This is a one-off. It's over $8 billion of non-U.S. cash being brought to the U.S. You won't see our U.S. cash balances go down by that full amount because some of it had been lent into the U.S., but we expect our year-end cash balances to be $3 billion to $4 billion lower than where we ended the third quarter. We ended the third quarter a little bit high because we were preparing for some of these moves to repatriate the cash.

Operator: Our next question comes from the line of Doug Leggate from Bank of America Merrill Lynch.

Douglas Leggate (Bank of America Merrill Lynch)
Thanks, everybody. Jay, I know you don't -- or maybe, Pierre, I know you guys don't normally want to talk about fiscal terms. But in light of the Tengiz's cost increases. I just wondered if you could just remind us or walk us through what the implications are for cost recovery, because I'm guessing that with existing production and like of ring-fencing and so on, the net impact of this may not be as severe as, obviously, the headline cost overrun suggested. I just wonder if you could walk us through what the cost recovery ramifications are, please? And I've got a follow-up.

Jay Johnson

Well, this is a tax and royalty contract in Tengiz. It is really going to be through the DD&A and the way that flows through the books in terms of the recovery. So, it's impacting returns more than it will the actual cash flow once we get past the start-up of the facility.

Douglas Leggate
I was under the impression it was going to accelerate the DD&A, is that not the case?

Jay Johnson
We're not going to discuss the terms of the contract, but it's a tax and royalty contract.

Pierre Breber
And just to be clear, when I refer to the less than $0.20, I'm talking about booked DD&A, not tax depreciation, which obviously is different.

Douglas Leggate
Okay. No, I'm sorry, I thought it was an accelerated piece to that. My follow-up is really more going back to the Permian. Obviously, the plan you've laid out is continuing to -- you continue to outperform against at least the production profile. But when you laid out the plan, you talked about when you would expect the Permian to be cash breakeven in terms of capital and cash flow and obviously, royalty contribution and so on. Obviously, NGL and gas prices have deteriorated quite materially. So, I'm wondering if you could just update your thoughts on that. And specifically, on the takeaway solutions that you've announced over the last several months. What does that do to your ability to improve gas and NGL realizations of those lease line? Or are they going to uplift your realizations with more to work in the Gulf Coast type metric to and I'll leave it there.

Jay Johnson
Well, we went through a lot of this, Doug, as you know, in the second quarter call, and that guidance still stands. In terms of the crude takeaway capacity, we have sufficient capacity, not just to produce it into the basin, but to take it to Houston, and now we have export capacity opening up as well, 35% now and 40% in 2020. So that's the crude side of things. NGLs are sufficient through 2020.

In terms of gas, our primary focus was to make sure we have evacuation capacity in the basin, and we have 100% of that covered. Our view and our practice is that we have no routine flaring of gas to enable production and we've been able to honor that. In terms of moving gas out of the basin, we have about 25% capacity, and it's going to vary based on how these different pipelines come on stream, but by second quarter of 2021, we're expecting to have about 80% of our gas flowing out of the basin. We are still expecting to be free cash flow positive next year.

Douglas Leggate
Jay, just to be clear, this is -- is the 60%, 65% gas in NGLs? Or can you -- I know you talk about liquids, but can you split the oil versus NGL portion, then I'll leave it at that.

Jay Johnson
We see roughly half of our total mix is in crude, about a quarter of it is in gas liquids and about quarter of it's in natural gas.

Operator: Our next question comes from the line of Dan Boyd from BMO Capital Markets.

Dan Boyd (BMO)

I just want to actually follow-up again on the TCO spend. And if I recall correctly, last year, you spent about $600 million more than you initially budgeted. So what I'm wondering is how much of the sort of overrun is going to be already spent or in the budget by the end of this year? That's sort of the first question. And then the follow-up is when I look at your total CapEx budget, in order to be below the $20 billion for next year, given that affiliate spending will still stay high. Are you implying that your cash CapEx could potentially be down next year? And I'm just wondering if there's a potential production impact of that or if the Permian is running ahead of schedule, enough to offset any of that.

Jay Johnson
A couple things, Dan. First of all, I'd take you to Slide 10, which shows our spending profile for the FGP project. We see 2018 and 2019 as our peak years of spend. As we look to 2020, we'll start spending at a lower rate as we consolidate the activities largely into site construction work. We have one more year of fabrication to go in one of the four original yards. That work is currently about 70% complete. In terms of how to allocate the incremental spend over the total project, I would say [relative to the original FID investment profile] it’s roughly half behind us and half in front of us – about $4 billion to $5 billion in front us. Where we are seeing the majority of the increase is in the increased construction costs. The part [earlier comments] in the engineering and fabrication was more directed around the consumption of contingency. The increases we've really seen now have been in construction and schedule.

Pierre Breber
We reaffirmed the guidance for next year between $18 to $20 billion. TCO will be coming off, as Jay said. So, we're finalizing our plan and our capital program right now. Between the efficiencies that Jay talked about and choices we can make around deferring low-return projects, we absolutely have the capability of landing a capital program in that range.

Dan Boyd
Okay. And the production outlook more than offset that in other areas? Yes.

Pierre Breber
I mean, we haven't given production guidance year-by-year. We've given the 3% to 4% production outlook to 2023. So, no change to that. Again, some of the examples, some of the offsets do not impact production. Clearly, if we defer some lower-return natural gas investments or we just decide to flex down some of our shorter cycle spend, that could have a modest impact on production, but there are other things that are going better, like the Permian and other offsets that we're trying to manage. –We will give our usual 1-year outlook on production guidance on the fourth quarter call in late January.

Operator: Our next question comes from the line Roger Read from Wells Fargo.

Roger Read
I guess, maybe it's been mentioned a couple of different times, the weakness in gas, maybe as you think about global gas markets, LNG, what you're seeing in terms of any additional risk we should think about on the spot market side or on the contracted side for LNG. And then there's a little add-on to that, just kind of an update of how Gorgon and Wheatstone are performing here in planned and unplanned maintenance?

Jay Johnson
Okay. Gorgon and Wheatstone are performing quite well. Gorgon Train 1 is currently under a scheduled turnaround of planned turnaround. But as you saw, our third quarter production, and there's a slide in the back was very strong out of both Gorgon and Wheatstone, and we continue to stay focused on enhancing the reliability and the utilization of those facilities as well as creeping the capacity.

We have a turnaround schedule that is going to be planned for both of those, and it'll be an annual event. We'll talk about those as we get closer to them. We have another train for Gorgon next year that has been announced. These will be done to allow us to get into a regular rotation of turnaround so they can be done safely and efficiently, just as we do in our downstream facilities and places like Tengiz.

We do see the potential for spot to be higher as we increase production as we hit stronger production, we will have more cargoes available for spot. That's a good thing because we have more production than we'd planned for. But over time, as the reliability continues to strengthen, we would expect to try and term up some of those anticipated spot cargoes and reduce the amount of spot in any given quarter relative to either long-term or medium-term contracts that we've put in place.

Pierre Breber
We have seen some customers downward flex on the long-term contracts. This is something that is within contractual limits and within the contractual terms. They must do it almost a year ahead and it's tied to the annual delivery schedule. We have seen some of that, and that has resulted in a little bit more in the spot market than we otherwise would have.

Roger Read
Any particular weakness in the spot markets that you're seeing at this point? Or are we pretty well past that for the summer time?

Pierre Breber
The macro on spot LNG looks sort of structurally oversupplied. Of course, a cold winter can certainly fix a fair amount of that, but storage levels in Europe are full and Asia seems to be well positioned. So, if I look at it right now, again, it looks oversupply and there's more LNG coming on. But markets surprised us all the time. I mean, the takeaway for us is we are just not really exposed to the spot market. We are primarily selling under oil-linked, long-term contracts.

Operator: Our next question comes from the line of Sam Margolin from Wolfe Research.

Sam Margolin (Wolfe)
So, my first question is on the Permian, and it's probably for Jay. I think it's well-understood that your leading-edge wells perform better and better. I'm interested as the base gets bigger and is more important to the overall production targets, how your first-generation wells look if your EURs that you projected look like they're intact or growing or changing in any way? And if there's sort of rig less activity work workover stuff that you have to do that you had modeled or maybe it's less than what you modeled, but just any update on kind of your older wells and how that component of the Permian is shaping up today would be great.

Jay Johnson
That's a good question, Sam. Thank you. When we look at our production performance out of our wells, the early horizontal wells have actually performed as we expected them to perform, so our EURs have been consistent with expectations for the wells as we move through. As we have continued to evolve our basis of design and our completion strategies, we've seen higher and higher EURs and the new wells are meeting those expectations as well. So overall, the program is working as planned. The newer wells, as you point out, are much more productive than some of the older wells, but they're all meeting the expectations that we've set for them at the time in the aggregate. Obviously, any individual well may be higher or lower than planned. But as a portfolio, as a program, we've been overall pleased with the performance. That's really what's underpinning our ability to deliver the production profile you can see on the chart in the appendix.

Sam Margolin
Follow-up, your leverage profile on the balance sheet - the net debt continues to fall. The ratio of your free cash flow annualized and not a great year to net debt is like 1.5x. Is there a level of net debt that you think is under levered for the business, especially in the context of Tengiz? If the biggest impact is a return impairment, you can enhance that to the equity with some leverage deployed somehow. Your thoughts on how net debt's trending and what optimal leverage is.

Pierre Breber
We are generating good cash in a challenging macro environment. I think you know our four financial priorities, I'll go through them quickly. The first is to sustain and grow the dividend, and we increased at 6% earlier this year. The second is to reinvest capital in the business. You heard Jay reaffirm our capital guidance. So, we are not going to add to our capital program. The third is to maintain a strong balance sheet, and that's what you're asking. Fourth is our buyback program that we intend to sustain through the cycle, and we have that at a $5 billion annual rate.

So, what happens in the short term? If we generate more cash than those three requirements, in particular, the dividend, which we increased earlier this year; the capital program, which we're holding flat; and the buyback program, then it goes to the balance sheet. That's where it's going to go in the short term. That's just how the math works. But over time, we expect if those conditions continue without speculating about future dividend increases or share buybacks.

Over time, that cash should be returned to shareholders in the form of higher dividends and a sustained buyback program because, as you say, we don't need to be an even stronger credit. We have the leading balance sheet in the industry with the strongest balance sheet in the industry. I've talked about a gross debt-to-capital ratio of 20% to 25%. We're well below that. I'm comfortable being below that because that's, again, the outcome of our cash generation profile, depending on where the macro environment. Obviously, that can change, but we are very well positioned to grow dividends, sustain the buyback, invest in the business and maintain a strong balance sheet.

Operator: And our final question for today comes from the line of Jason Gabelman of Cowen.

Jason Gabelman (Cowen)
Firstly, quickly confirm that 2019 CapEx hasn't changed as a result of the TCO overspend and then secondly, I just wanted to get your thoughts on M&A that hasn't been addressed this call. I think in the past, you've discussed wanting to kind of expand or potentially acquire some company that operates in multiple arenas, not just one that operates in U.S. shale. I'm wondering if that's still the way you're thinking about M&A and how the opportunity set looks right now?

Pierre Breber
On your first question on capital for this year. Our capital budget on an organic basis is $20 billion. Year-to-date, we're at $14.5 billion. So, we're basically on track. We've had some modest inorganic capital year-to-date, that's been the Pasadena Refinery primarily, and we guided to a little bit for the Brazil exploration bid around. So again, we're on track for delivering an organic capital program in line with our budget of $20 billion.

In terms of M&A, I'm not going to speculate on that. I think you've heard us talk about it. We have a very strong value proposition. We have a 4% dividend yield, a 2% share buyback or the buyback equivalent to 2% of the shares, a free cash flow yield of 7%, an advantaged portfolio with strong resources and reserves that allow us to grow cash flow and grow production over time. So, we don't need to do a deal. All that said, at times in the past, we have been opportunistic when we think it's in the interest of our shareholders. It is difficult to make M&A work for our shareholders. And right now, we think we have a very good value proposition on our own for our shareholders.

Wayne Borduin: Thanks for your participation that is the end of our call today.