2Q23 Earnings Conference Call
Edited Transcript

Friday, July 28, 2023

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This transcript is meant to be read in conjunction with the Second Quarter 2023 presentation posted on chevron.com under the headings "Investors," "Events & Presentations."

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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."

Operator: Good morning. My name is Katie, and I will be your conference facilitator today.

Welcome to Chevron's Second Quarter 2023 Earnings Conference Call. At this time, all participants are in a listen-only mode. After the speaker's remarks, there will be a question and answer session, and instructions will be given at that time. If anyone should require assistance during the conference call, please press star then zero on your touchtone telephone. As a reminder, this conference call is being recorded. I will now turn the conference call over to General Manager of Investor Relations of Chevron Corporation, Mr. Jake Spiering. Please go ahead.

Jake Spiering: Thank you, Katie.

Welcome to Chevron's second quarter 2023 earnings conference call and webcast. I'm Jake Spiering, General Manager of Investor Relations. Our Chairman and CEO, Mike Wirth, and CFO, Pierre Breber, are on the call with me today.

We will refer to the slides and prepared remarks that are available on Chevron's website. Before we begin, please be reminded that this presentation contains estimates, projections, and other forward-looking statements. Please review the cautionary statement on Slide 2. Now, I will turn it over to Mike.

Mike Wirth: Thanks, Jake, and thank you everyone for joining us today.

Earlier this week, we announced several senior leadership changes, including Pierre's plans to retire next year, along with second quarter performance highlights.

In a few minutes, Pierre will share more details on our financials, which included return on capital employed greater than 12% for the eighth consecutive quarter and another quarterly record in shareholder distributions of more than $7 billion.

At TCO, we're making good progress with commissioning and pre-start up activities, including introducing fuel gas to new facilities.

In the third quarter, we expect mechanical completion for the Future Growth Project (FGP) and to complete a major turnaround.

Cost and schedule guidance is unchanged. Conversion of the field from high-pressure to low-pressure is expected to begin late this year and FGP is on track to start up by mid-next year. We have unused contingency which gives us confidence that we'll complete the project within the total budget.

After completion of these projects, TCO is expected to deliver production greater than 1 million barrels of oil equivalent per day and generate about $5 billion of free cash flow – Chevron share at $60 Brent – in 2025.

Chevron's Permian production set another record in the second quarter, about 5% above the previous quarterly high. We expect next quarter's production to be roughly flat before growing again in the fourth quarter, on track with our full-year guidance.

Early 2023 well performance in our company-operated assets, in all three areas, is consistent with our plans. In New Mexico, we've put on production (POP) 10 wells. Before year-end, we expect to POP an additional 30 wells with higher expected production rates.

As a reminder, about half of Chevron's [Permian] production is company operated with the balance non-operated and royalty production.

While short-term well performance is one measure, we're focused on maximizing value from our unique, large resource base [that is] expected to deliver decades of high-return production.

Over the next five years, we expect to develop over 2,200 net new wells, growing production while delivering return on capital employed near 30% and free cash flow greater than $5 billion in 2027 at $60 Brent. Longer term, we've identified well over 6,000 economic net well locations that support a plateau greater than 1 million barrels per day through the end of next decade.

Our deep resource inventory and advantaged royalty position allow us to optimize our development plans for high returns, incorporating learnings and technology improvements, as we expect to deliver strong free cash flow for years to come.

In the deepwater Gulf of Mexico, the floating production unit at Anchor is on location and the project remains on track for first oil next year. We continue to build on our exploration success and were awarded the highest number of blocks in the most recent lease round.

In the Eastern Med[iterranean], our Aphrodite appraisal well in Cypress met our expectations and we've submitted a development concept to the government. At Leviathan, we're expanding pipeline capacity to nearly 1.4 BCF per day.

We expect to close our acquisition of PDC Energy in August after their shareholder vote next week. Our teams are working on integration plans and we look forward to welcoming PDC's talented employees to Chevron.

Now over to Pierre.

Pierre Breber: As Mike said, strong, consistent financial performance enabled Chevron to return record cash to shareholders this quarter while also investing within our capex budget and paying down debt.

Working capital lowered cash flow primarily due to true-up tax payments outside the U.S. Excluding tax payments, working capital movements are variable. Our typical pattern in the second half of the year is to draw down working capital.

Chevron's net debt ratio ended the quarter at 7%, significantly below the low end of our guidance range. Surplus cash on the balance sheet was reduced during the quarter with cash balances ending at $9.6 billion, well above the cash required to run the company.

Adjusted second quarter earnings were down $5.6 billion versus the same quarter last year.

Adjusted Upstream earnings were lower mainly due to realizations partly offset by higher liftings. Other includes primarily favorable tax items and income from Venezuela non-equity investments.

Adjusted Downstream earnings decreased primarily due to lower refining margins. Opex was up mainly due to higher transportation costs and the inclusion of REG.

Compared with last quarter, adjusted earnings were down $900 million.

Adjusted Upstream earnings decreased primarily due to lower realizations. This was partially offset by higher production in the U.S. and non-recurring tax benefits.

Adjusted Downstream earnings were down modestly, lower margins were partially offset with higher volumes.

Second quarter oil equivalent production was down about 20 thousand barrels per day from last quarter, primarily due to planned turnarounds at Gorgon and in the Gulf of Mexico and downtime associated with the Canadian wildfires. This was mostly offset by growth in the Permian.

Now, looking ahead.

In the third quarter, we have a planned turnaround at TCO and a planned pit stop at Gorgon, completed earlier this week. Our full-year production outlook is trending near the low end of the annual guidance range.

Since PDC's proxy solicitation on July 7th, we've not been permitted to buy back our shares. After we close the acquisition in August, we plan to resume buybacks at the $17.5 billion annual rate, which we expect to continue through the fourth quarter. We do not expect a dividend from TCO until the fourth quarter. Full-year affiliate dividends are expected to be near the low end of our guidance.

Putting it all together, we delivered another quarter with solid financial results, strong project execution and continued return of cash to shareholders. Our approach is consistent and you can see that in our actions and results.

Back to you, Jake.

Jake Spiering: That concludes our prepared remarks. We are now ready to take your questions.

Please limit yourself to one question and one follow-up. We will do our best to get all of your questions answered.

Katie, please open the lines.

Operator: Thank you. If you have a question at this time, please press star one on your touchtone telephone. You may ask one question and a follow-up question. If your question has been answered or you wish to remove yourself from the queue, please press star two. If you are listening on a speakerphone, we ask you lift your handset before asking your question to provide optimum sound quality. Again, if you have a question, please press star one on your touchtone telephone.

Our first question comes from John Royall with J.P. Morgan.

John Royall: (J.P. Morgan) Hi. Good morning and glad to be the first on this call to congratulate Pierre on his retirement.

My first question is on Upstream production. Can you bridge us from the midpoint of your production guidance to the low end that you mentioned in the opening? Sounds like the

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Permian is on plan. What pieces have come in below the midpoint of plan to move you to that low end?

Mike Wirth: John, guidance remains unchanged. We expect to be at the lower end of that [production guidance range]. As we said, Permian production has been strong. The things that Pierre mentioned are the key things that we've seen. There has been some impact of fires in Canada that have impacted [our production, but] not really our operations perse. We did some evacuations on a precautionary basis, but [there was] midstream and processing downtime that [did not allow us] to move our production to market.

[Thailand] Benchamas is the other one. We have an FPSO in Thailand that had an incident early in the year and was taken off station. That's another 10 or 11 thousand barrels a day net which is off for the foreseeable future. Those two things are the ones that are pushing us down that were both unexpected.

John Royall: Great. Thanks, Mike. And then my next question is just sticking to production, but just drilling in a bit on the Permian. The well results generally look very strong in the first half, but still a bit below 2022 in New Mexico. Maybe you can just update us on what inning you think you're in, just in terms of optimizing the single-bench developments in New Mexico?

Mike Wirth: The thing I think is important to bear in mind is [in the] New Mexico type curve we showed [Slide 5], there are only 10 POPs represented, or 10 POPs that we achieved, all in the second quarter. There are no first-quarter POPs, and there [are] only seven [POPs] that had enough data to make it into the curve you see on the chart. It's a very thin set of data. We expect 30 more [New Mexico] POPs in the second half of this year. The bulk of the program is not represented in those curves.

There are a couple of other things. The [New Mexico] wells we did POP have had some facility constraints that have limited full productivity. We actually haven't been able to move all the production due to some third-party facility constraints that we faced. The rest of the program is in a different part of the New Mexico portion of the Delaware [Basin] where we expect higher productivity.

It's a combination of things. I'd caution you not to over-index on a very thin data set, with a lot more data to come in the second half of the year.

Operator: Thank you. We'll go next to Devin McDermott with Morgan Stanley.

Devin McDermott: (Morgan Stanley) Hey, good morning. Thanks for taking my question and Pierre congrats on the retirement.

I wanted to just stick with the Permian since we're on that topic. I was wondering if you could talk a little bit just around the mixed trend you're seeing there? And if we disaggregate the productivity a little bit further, you talk about how much of the uplift is coming from gas and NGLs versus oil. And then similarly, as you progress towards some of your longer-term production goals, how do you expect the mix in the basin for you to trend oil, gas, NGLs, over time?

Mike Wirth: Devin, we're still drilling primary benches so we can optimize the oil cut. Across the [Permian] basin, our production remains roughly 50% oil, 25% NGLs, 25% gas. We look at all the commodities – oil, NGLs and gas, and have our own long-term views on prices and markets to run the economics to optimize to returns.

The gas-oil ratio, in aggregate, has been relatively flat for a number of years and we don't see it changing a lot. It can vary a little bit in different parts of the [Permian] basin, but if you take it for our whole [Permian] portfolio that 50 [% oil], 25 [% NGLs], 25 [% gas] remains a pretty good way for you to think about it.

Devin McDermott: Great. I wanted to shift over to TCO. Good to hear the continued positive progress there as we get closer to the finish line. There's a lot of moving pieces over the next year, year and a half, as we get the two phases of development online. You give the guidance for the turnaround impact in 3Q. I was wondering if you'd talk a little bit more about how you see the evolution of production into the fourth quarter of this year and then through 2024 as we get to that 2025 run rate. So shape it a bit for us as we look out over the next few quarters.

Mike Wirth: The headline here is no change to cost and schedule. I think that's really important. In the second quarter we made really good progress. As we said, 98% project completion and commissioning is essentially two-thirds complete. In the second quarter, we achieved mechanical completion of the 3GI gas injection facilities and got fuel gas into the flare system, which is very important to enable an on-time start-up of FGP.

In the third quarter, we expect full mechanical completion of the Future Growth Project and also a turnaround at one of the complex technology lines (KTLs). We'll begin a lot of work and start-up on utility systems, boilers, steam system [and] other utilities that are required for start-up of the pressure boost facility, which is the key driver of WPMP, which enables us to convert from high-pressure to low-pressure across the field.

Once that turnaround is done in the third quarter, and you will see some production impact, Pierre guided to that. We expect to have two of the four big pressure boost compressors online, which allows us to begin the conversion of metering stations from high-pressure to low-pressure. We'll get that started at the end of this year. It will take 10 to 12 months for all of those conversions to occur next year.

There will be [two] turnarounds next year as well, one at SGI (Sour Gas Injection) and another one in one of the KTLs. All of that is part of a very carefully choreographed sequencing of turnarounds and start-up activity that will bring the full field to the million barrels a day for 2025.

As we indicated at our investor day, what you're going to see in 2023 and 2024 is the normal turnaround activity interlaced with project start-up activity. This is not as simple as bringing on a new portion of the field. We're really reworking the entire gathering and producing capacity of the field. It's quite a complex series of activities to execute all of that and the production reflects that. We put in CID a chart to give you some guidance for both this year and next year.

Pierre Breber: Slide 10 from our CID [slides] has annual production [for] 2023, 2024, 2025. No change in that guidance.

Operator: Thank you. We'll go next to Neil Mehta with Goldman Sachs.

Neil Mehta: (Goldman Sachs) Good morning, team.

I want to stay on TCO. While there will be a volume inflection in 2025, there's probably going to be a pre-free cash flow inflection in 2024, just as affiliate capex rolls off first. Can you talk about the cadence of that and how it manifests itself in terms of dividends?

Pierre Breber: We've been guiding, Neil, to the clean year, because that's the $5 billion of free cash flow at $60 Brent in 2025. We're guiding to free cash flow, because as you recall, it's not just dividends, it's also repayment of the loans and the co-lending we have done along the way. The profile of those loans are disclosed in our SEC filings.

To your point, you'll see a build towards that [inflection point] just as the [affiliate] capex has rolled off. It was not that long ago we were investing $3 to $4 billion a year, our share, into the project, and that's down to $1.5 billion or so this year and will continue to trend down, so there is that inflection point. What is also being managed are commodity prices and those vary.

As we've said, TCO continues to be conservative in managing its' balance sheet [and has] been holding more cash on the balance sheet. As the project gets closer to the end, as we've demonstrated that CPC is running very reliably now for almost a year and a half, we expect some of that cash to come on.

I can't get in front of the Board of Directors of TCO. [TCO is] a separate company that we are a shareholder in. We expect, as we've said, a much bigger dividend in the fourth quarter than we saw in 2Q. We expect to see a release of some of that surplus cash that's been held on the balance sheet, and that will continue over the next couple years as we head into that $5 billion of free cash flow [guidance] in 2025.

And the last thing, Neil, I know you know this. TCO has really good price sensitivities. I've seen yours and other estimates at $70 or $80 [Brent], the cash flow is even stronger.

Neil Mehta: Thanks, Pierre. That was great. The follow-up is just on the return of capital. I think while you have a big buyback range, a lot of market participants have viewed your $17.5 billion [annual rate] as the P50 outcome in any reasonable commodity price environment. Thinking less of it like a flywheel and more as a relatively fixed number, unless commodity prices go wacky. Any thoughts on that statement and whether you're trying to give us a little bit more assur[ance] around that number as opposed to a more volatile number?

Pierre Breber: The range, Neil, is tied to the up-side downside cases that we showed at our investor day, roughly. There's [a] $10 to $20 billion [range]. You're right, it's a wide range because it reflects a wide range of [commodity] prices between that up-side case and the downside case, and in between there's a mid-cycle case. As a reminder, that downside case gets to $50 [Brent] in a couple years and stays there for three years. That is a real downside case, and that's what the low end of the buyback range is notionally tied to.

The up-side case is a case that's not too different from what we're seeing now. It averages about $85 [Brent] over the five-year period. It trends down to $70 [Brent] towards the end of that period, and that's why you're seeing a buyback very close to the top end of the range at the $17.5 billion [annual rate].

It's certainly a signal that as we look out over this commodity cycle, and again, we think of the buybacks as being steady across a cycle, that we feel good about it. We've said we could do a much larger buyback, but that would not be steady. We don't want to be pro-cyclical, we're trying to be across the cycle. When we guide on buybacks, we're guiding with the intent of maintaining it for a number of years across the cycle.

Mike Wirth: Neil, I would just add, you see in our second quarter results our net debt remains very low. We've indicated multiple times that we don't have a problem gearing back up and putting more debt on the balance sheet to get back towards the range that we've guided to through the cycle in order to sustain a very steady share repurchase program.

Operator: Thank you. We'll go next to Stephen Richardson with Evercore ISI.

Stephen Richardson: (Evercore ISI) Thanks. Good morning.

Mike, I was wondering if you could talk a little bit about New Energies? I think you've been clear from the beginning that build versus buy was part of the consideration [for] a lot of these businesses. We saw a big CO_2 pipeline and EOR company transact recently, so maybe you can talk a little bit about the CCUS business as you view it, and why build versus buy is maybe the better choice for Chevron? Then maybe I just get ahead of it with a follow-up, you could give us a little bit of an update on Bayou Bend, please?

Mike Wirth: I'll put those two together, actually. We will do both, build and buy, in New Energies. I would fully expect us to do that. In renewable fuels, we have built a business, but then we also went out and acquired Renewable Energy Group (REG). I think you'll see both.

Certainly, the Denbury transaction is one that the market somewhat anticipated, and you can presume that multiple market players probably took a look at or had conversations with Denbury.

For us, in CCUS, we look for areas that have good geology or pore space. They're near concentrated emissions and have the right policy support to enable a business. The Gulf Coast has all of these things.

In Bayou Bend, we've got about 140 thousand acres of permanent CO_2 pore space, both onshore and offshore. We've got storage potential there of greater than 1 billion metric tons. In the second half of this year, we're going to drill a strat[igraphic] well in the offshore acreage to further delineate and characterize the subsurface. In the first part of next year, we expect to drill a strat[igraphic] well in the onshore acreage and do the same.

We're in conversations with a number of customers in that region – in the Golden Triangle up at Mont Belvieu, all the way across the Houston Ship channel. We've got term sheets going back and forth. We're in negotiations with a number of different potential customers. The commercial framework for this is still evolving and we're working on the other pieces you need – Class VI well injection permits and midstream assets.

We've got an RFP out right now with a number of midstream providers consistent with the way we have generally approached the midstream. We own assets if they're strategic. If there's a way for us to go to somebody who's in the business of building and operating midstream infrastructure, we certainly look at that as well.

We're putting all the pieces together there for a phased development. We like the Bayou Bend project and we'll report more. To your underlying question, we'll build organically and we'll do inorganic where it makes sense.

Stephen Richardson: Thanks very much.

Operator: Thank you. We'll take our next question from Biraj Borkhataria with RBC.

Biraj Borkhataria: (RBC) Hi, thanks for taking my questions and Pierre best of luck with retirement.

My first one is on portfolio concentration. At your analyst day, you talked about just over $20 billion of free cash flow at $60 [Brent] a barrel and looking through today's slides roughly half of that in the medium term will come from the Permian plus TCO. I understand you want every dollar to go to the highest level of return, which is completely sensible, but I was wondering if you can talk about portfolio concentration because it is quite unusual for a super major to have that level of concentration in terms of free cash flow. How do you think about portfolio diversity, and is this something you are actively trying to address going forward? I've got a follow-up on a different topic. Thank you.

Mike Wirth: Biraj, if you look back over the last decade, we've cleaned up our portfolio. We had a lot of assets that were at the smaller end of the tail that pulled capital and management time and resources. We want to be diversified. We've got a diverse portfolio, but we don't need to be diversified just for the sake of it. We want to have assets that have scale and are material and long lived.

You can start in the far east and look at our LNG positions in Australia, which aren't drawing a lot of capital right now, but are throwing off a lot of cash. We've got a strong position in West Africa that we strengthened with the Noble acquisition and the EG assets that can feed LNG into Europe.

You mentioned TCO. The Eastern Med is a very strong position. We've recently taken FID and are working on expansion projects for tomorrow, Leviathan, and have submitted a concept on Aphrodite, so there's a lot of opportunity in that asset. When we close PDC, we're going to be producing 400 thousand barrels a day in the DJ Basin.

We've talked about some of our Other Shale and Tight assets in Argentina, in Canada. We've got two crackers [major capital projects] underway in CPChem that'll come online middle of this decade. One in the U.S., one in the Middle East. We've acquired REG and are growing our renewable fuels business. We have exposure across a large portfolio.

We also have projects coming online in the Gulf of Mexico. I mentioned Anchor earlier, Whale, Ballymore. We recently acquired more leases in this recent lease sale, twice as many leases, [than] the biggest lease sale over the last eight years. We're adding to our position in the Gulf of Mexico.

This idea that we are a two-asset company, the Permian and TCO, I don't think really stands up to careful inspection. They're two great assets, so they get a lot of attention, but we've got a lot of other strong assets in our portfolio.

Pierre Breber: If I can just build off that and go to the return of capital question that Neil asked. That’s what gives us confidence, not only on the buyback, but on the track record of dividend growth. We guided to 10% annual free cash flow coming from all those businesses. Some are holding cash constant, some are growing cash flow that Mike covered, and that goes to leading dividend growth where we've grown the dividend over the last five years at rates double our closest peer, and much higher than others and where we have a buyback that is nearly 6% of our shares outstanding annually.

Our business is built for $50 [Brent]. Part of the confidence in our ability currently, if you look at our breakeven and adjust for working capital this quarter, if you look at the last four quarters, it's actually probably a little bit lower than that with the strong refining margins that we've been seeing. We're built for lower prices. Free cash flow is going to grow from this space. That should give investors confidence in our ability to continue to grow the dividend at leading rates and to maintain buybacks at also very high rates.

Biraj Borkhataria: I've got just a follow-up on a different question. Through the Permian, you'll be producing a lot more gas over time, and you have expressed a desire to grow in LNG. You've signed a couple of deals as an offtaker to synthetically integrate your U.S. gas position to global markets.

I wanted to ask about whether you'd be interested in owning liquefaction or whether you feel being an offtaker is enough? Because some of your peers have argued the benefits of integration and owning through the value chain, but I think in the past you've noticed the returns are typically lower.

I'm particularly interested in asking that question now because a number of players have signed offtake agreements with companies such as Venture Global, and then actually they're not receiving the gas as agreed. Interested how you're thinking about that value chain in LNG? Thanks.

Mike Wirth: It's consistent with what we've described earlier, and I think you've captured it. It depends on the circumstance. In places where we've got remote gas, where you need to be in the entire value chain and you can create an economic model that supports the investment, we've done that.

In other locations where you've got other people that will put capital into the midstream assets, and we can sell gas into that, we can offtake gas off of it, but not participate in some of the very capital intensive and lower return portions of the value chain. That's certainly a model that helps us support our aspiration to drive higher returns.

You have to have good partners. You have to have reliable operations. We'll work closely with the companies that we have offtake with. We vet them carefully and we have confidence in the people that we are working with to provide those reliable operations. We're really looking to drive high returns, not necessarily to own assets for the sake of control, unless it creates a differentiated value proposition.

Operator: Thank you. We'll take our next question from Sam Margolin with Wolfe Research.

Sam Margolin: (Wolfe Research) Hello.

The question is on the cash balance. It looks like nominally it's drawing down, but it feels there's some inputs that would theoretically help it rebuild in the second half. You've got working capital, and I think TCO's going to pay a dividend in third quarter, and PDC had a very front-loaded capital program too, so that's coming on with free cash. Just wondering about the cash balance and how you think about the level or if we're going to be in a rebuild phase for 2H?

Pierre Breber: The direction that it goes depends on commodity prices and margins and a number of other factors. You're right, our cash levels have come down, in part due to working capital outflows, timing with affiliate dividends, and we've also paid down some debt.

We've been, I think, very clear that we don't want to hold surplus cash, certainly not permanently. It's where the cash goes in the short term, but over time that cash is going to be returned to our shareholders in the form of this growing dividend and ratable buyback program. We need only about $5 billion [in cash] to support our operations. We are nearly $10 billion [in cash] at the end of the second quarter, so that's more than sufficient. We have access to lots of liquidity, we don't have any commercial paper now, [and] we've been paying down debt.

That's the more economically efficient way to manage the balance sheet if we get there. Whether the cash balance goes up or down, depends on all the inputs and outputs that we've been showing.

We're guiding towards the net debt. As Mike said, the net debt is well below the low end of our guidance range. We look at all those factors and if cash balances head down to $5 billion, that'll be adequate to cover the operations.

On working capital, our pattern the second half of the year is that we tend to see some draws on it, but we're certainly not going to recover from what we see in this first half of the year. A big portion of what we saw in the first half of this year on working capital are really tax payments tied to earnings last year. You can think of those as being offset from last year where we had a favorable working capital environment.

There will be ups and downs along the way. Over time working capital tends to average out over zero, but these are just timing effects. We look through them. We knew we had taxes due and that's all part of the planning as we look at the balance sheet.

Jake Spiering: Sam, we've guided to a TCO dividend in the fourth quarter. We do not expect a dividend in the third quarter.

Sam Margolin: Got it. I must've misread that remark. The follow-up is actually on the organization, it's a follow up to Steve's question earlier. Pierre had spent some time in the ESG role, in a low carbon role, and the incoming CFO is coming from a role where there was a lot of work on the ground on the low carbon front, on the technology side. Chevron has this really interesting marriage between finance and low carbon that I think is differentiated when you look at some of the peers.

The question is, as we make progress through the low carbon development, do you feel like you're embedded in the highest return areas or are there other ones where capital is going to maybe pivot? I think that ties into carbon capture too because that seems like a place where the incentives are pretty transparent.

Mike Wirth: Sam, I think your question started with people and ended up at our investment priorities in New Energies. Across the entire leadership team we've got a commitment to driving higher returns and lower carbon, and people move through different kinds of roles, but this is part of every role in the company today. It's a part of the business, it's something we're committed to.

Our focus is, as we've said before, on things where we can leverage our unique capabilities, assets, value chains, customers, to create sustainable competitive advantage in these new energy businesses. It's why we've not gone into wind and solar on a merchant basis, because there's others that can do that and we don't really bring anything unique there.

Our renewable fuels business today is profitable and generating cash. We expect to start-up the Geismar expansion and be producing more renewable diesel next year, so that's a business today that is economic and attractive and we continue to grow. Particularly back into the feedstock side, we announced an acquisition this last quarter of a small company that's got some interesting feedstock technology.

Carbon capture and storage is being built. We do it today in some assets, but as a business we're building out Bayou Bend [as] I talked about. We're working on projects in other parts of the world as well. We do believe that with the right technology, the right business model and policy environment, that there's an opportunity there.

There are other things that we are working on. Hydrogen is one that both electrolytic hydrogen and traditional hydrogen [can be] paired with carbon capture storage. In the U.S., the IRA incentives can certainly support the development of business models there.

I think we'll stay consistent with this. We're always looking at new technologies, but the areas we [are] focused on are the primary areas you should expect to see us investing.

Operator: Thank you. We'll go next to Jason Gabelman with TD Cowen.

Jason Gabelman: (TD Cowen) Hey, morning. And Pierre, congrats on your retirement.

I'd like to go back to the Permian detail for a minute if I could and two questions on this. First, has capex in the Permian deviated at all from that $4 billion budget that you highlighted at the analyst day. The second part, on the Permian inventory over the five-year plan and long term, what percentage of those locations would you categorize as tier one? Thanks.

Mike Wirth: Jason, Permian capex is up a little bit this year, primarily [due to] three things. Number one, we've actually seen drilling performance continue to improve, and completions performance continue to improve. Out of the same fleet of rigs and completion spreads, we're getting more work done, which means you consume more tubulars, more sand, more water, etcetera. So that's a good thing.

We're seeing some longer lead times on some of the critical elements in facilities. We've actually had to make some long-lead purchases for next year's program that we didn't anticipate as we were lining out this year's program. And then, we've increased facility scope for water handling in some areas of the Permian, particularly as we're trying to manage some of these induced seismicity issues. We're being more careful, we're moving more water, so that has all led to some increase in capex.

Not a lot of inflation there. The inflation's been largely in line with what we had expected and the rig fleet is being activated in line with what we expected.

Your second question on inventory, we haven't broken our portfolio into tiers. There's not a very clear definition of that and a way to do that on a standard basis. When we've outlined the drilling locations and the long-term guidance, it's really based on economics. We've got locations that are economic at our price view for the future, which has historically not been a super aggressive price view. It's based on today's technology.

As indicated; we've got more than 6,000 locations in that outer time window that are economic based on those assumptions. By the time we get to that window, we may or may not see a different price environment. I fully expect we'll see a different technology environment, which can allow that number to grow even further. We look at it more in terms of the economics of the development than tiers.

Jason Gabelman: Great. Thanks. And my follow-up, just going back to TCO, you made some comments on maintenance effects over the next four quarters, and I know you showed it graphically. Are you able to quantify the actual impact to production over the next four quarters from all these turnarounds and start-up activities?

Pierre Breber: Jason, we do [include] it quarterly. It's included in the third-quarter guidance that we provided, and we'll continue to do that quarterly. You're seeing it annually. We're giving annual guidance on TCO. It's all embedded in there. I think we showed it relative to 2022, but there's a lot of moving parts. We'll continue to give that guidance each quarter, and you have annual guidance that incorporates all of that.

Operator: Thank you. We'll take our next question from Irene Himona with Société Générale.

Irene Himona: (SocGen) Thank you very much.

My first question is on the Downstream. If you can talk around the performance of your chemicals affiliates in particular in Q2 and what you're seeing so far in the third quarter? Also, what you would expect in terms of refining margin evolution in the second half of the year, given the weakness in Q2? Thank you.

Mike Wirth: The chemicals business is cyclical, as everybody knows. We're certainly at a period now where we're seeing some length in supply due to new build facilities. There's some length there, it's weighed on margins in the olefins chain.

In the short term, we think we're going to continue to see that would be a pretty tough sector. Longer term, as you get out to mid-decade and beyond, demand will continue to grow, and we expect demand and supply will come into a better balance. We'll see those margins recover out towards the middle and second part of this decade.

On your second question, certainly, we've seen refining margins come off the very strong levels that they were at last year. There's been some new capacity come into the system around the world, some big new refineries that have begun to start-up, or major projects that have come online, and so margins have softened year on year.

Certainly, the West Coast in our portfolio is important. West Coast margins, both in the refining and the marketing part of the value chain, have held up a little bit better because it's a market that is a little bit more cut off from the rest of the world than the Gulf Coast or Asia. Demand continues to be pretty strong out there. Gasoline demand is strong. Jet demand continues to come back. Diesel demand has maybe flattened out a little bit, but certainly holding.

We're in an environment where I would expect inventories are towards the lower end on the products in a number of parts of the world. I think refining margins for the second half of this year are likely to be as good as they were in the first half of the year at least.

Irene Himona: Thank you. On the Eastern Med, following your FID for the pipeline in Israel, I was wondering is that it for the time being for Leviathan, or do the partners continue to examine other options like FLNG, for example? Thank you.

Mike Wirth: Yes, we continue to evaluate other options. In fact, we're working towards a concept select for the next expansion of Leviathan, ideally at the end of this year. Floating LNG is one of the concepts that we continue to look at.

Operator: Thank you. We'll go next to Ryan Todd with Piper Sandler.

Ryan Todd: (Piper Sandler) Great. Thank you.

If I could follow-up on some earlier Permian conversations. You talked a little bit about some of the New Mexico well performance, but on well performance overall that you disclosed, it appears that first-half results are showing improved performance across much of the basin as you expected. What have you seen to date in terms of addressing some of the concerns from last year, particularly what have you learned regarding spacing, single versus multi-bench approach, etcetera, on the wells that you've done so far this year?

Mike Wirth: The performance is really consistent with our expectations and what we outlined at our investor day earlier this year, Ryan. There are a couple of things to remember. I mentioned earlier, in New Mexico we saw some infrastructure and third-party constraints, and we've got that in some other parts of our portfolio as well.

There are things that will show up on these curves that are not necessarily just a reflection of the geology and the well performance. As we continue to change our development strategy on well spacing, proppant loading, well length, etcetera, those will continue to be reflected in these curves.

The thing that is really important is we put production out there because everybody likes to see it. We're not optimizing the production, we're optimizing the returns. Fluid mix, EOR, capital investments, are all important parts of what we're optimizing too.

It's harder for you to see all the things that we're looking to optimize to drive returns when you're just looking at production. The high-level answer is performance is in line with the expectations as we've continued to evolve our program.

Ryan Todd: Okay. Thanks. If we turn to the Gulf of Mexico, as we think about your Gulf of Mexico deepwater portfolio, you've got an impressive string of project start-ups coming over the next few years. How exposed are you to escalating trends in deepwater drilling and development costs? As you look across those projects, do you have costs locked in across some of those projects rigs under multi-year contracts, etcetera? How much are you able to mitigate cost escalation as we think over capex requirements over the next few years?

Pierre Breber: Those projects were contracted at a different time. They reflect mostly locked-in rates as you'd expect. Procurements' well behind us as those projects are pretty far along. For new exploration activity, we will get exposed to some of the higher rig rates on that, but for the existing major capital projects, [costs are] largely locked in.

Mike Wirth: We came into the year with three rigs under contracts that were contracted back in a different environment.

Jake Spiering: Thanks, Ryan.

Operator: We'll go next to Paul Cheng with Scotiabank.

Paul Cheng: (Scotiabank) Hey guys, good morning.

First, I want to wish Pierre an exciting and very happy post-retirement. Thank you for the help over the past 20-plus years. Maybe there are two questions if I could. One, you submitted a development plan in Cyprus discovery. Can you give us a little bit in terms of the timeline, what should we expect? Also, what is the preliminary design of the development going to look like in [terms of] scale, and what [timeline is] it going to see first oil?

The second question, that we haven't talked much about is Argentina. Over there, the government seems to be pretty excited with the shale oil development, and you have a position there. Can you give us an update? What is your thinking over there? Thank you.

Mike Wirth: Paul, in Cyprus we're pleased with the outcome of the recent appraisal well. We've submitted our development plan to the government for their approval. It involves a capital efficient way to take the gas to market via subsea tiebacks to existing infrastructure, but this is all pending government approval. If we get that we could be into FEED (Front End Engineering Design) later this year, but it's a little early for us to really lay anything out on first gas. As we get through the government approval process, we'll be back to talk to you about the timeline on that one.

On Argentina, we remain very positive on the resource there. There's an election coming up. The country's got some macroeconomic challenges that it's facing right now, but we like Vaca Muerta, particularly our El Trapial area, where we're doing some more development work now with some increased capital that flows with that. We'll talk to you about that at investor day and beyond, but no real changes there. It's going to be part of the growth story.

Pierre Breber: Thanks, Paul.

Paul Cheng: Thank you.

Operator: We will go next to Doug Leggate with Bank of America.

Chevron

Doug Leggate: (Bank of America)

Thanks for getting me on, guys.

Pierre, it's been a pleasure. Congratulations, and good luck to everybody. And Mike to you as well on your extended tenure. My first questions on the Permian ratability. It looks like you've got about a couple of hundred POPs this year, wells to sales, 2,000 over the next five years. Is that ratable? How should we think about the step up in activity?

Pierre Breber:

The COOP [company-operated] POPs is 200, but if you were to include net POPs, half of our portfolio is non-op and royalty, it'd be more like 300 [POPs], so it looks more consistent. The long-term plateau and the well inventory, the 2,200 over the next five years, incorporates all of the activity, and the POP data was just on company operated. There is some increase, but not as large as it looks. You've just got to get apples to apples.

Doug Leggate:

Fairly ratable, Pierre? like 500 [POPs] a year type of deal, or 400 [POPs] a year type of deal?

Pierre Breber:

As we get up to activity, and as Mike said we're becoming more efficient as [are] our other operators that we work with, it's going to be pretty ratable once we get up to our full-rate activity.

Mike Wirth:

And of course, Doug, quarter to quarter there's some variability as we saw first quarter to second quarter this year. Third quarter is going to be [flat], so there can be some surges and plateaus quarter to quarter, but on an annual basis, it's going to be pretty ratable.

Doug Leggate:

That's helpful. Thank you. My follow-up guys is on Tengiz, but it's a slightly a different question. I guess Pierre and I are similar vintage. You signed Tengiz in 1993. It expires six years after the end of your analyst date trajectory through 2027, and it's a quarter of your free cash flow. So, my question is, what are your options there, whether it'd extended or replaced? And perhaps maybe some color on what the production profile looks like post-2027? Would have it going into fairly severe decline after 2030? So just want to know what you're thinking about the long-term sustainability of those free cash flows.

Mike Wirth:

The concession's a decade away. We're focused on delivering the project right now. This is a big, complex asset, a big, complex project. We'll certainly be in discussions with the government over time about potential extension of this. It'll reflect what we see in terms of reservoir performance and in production opportunities out into the future. These concession discussions have to create value for the country and for Chevron, so we've got to find something that works for both parties.

We've walked away from concessions as you've covered extensively, Doug, where it didn't work for us in places like Indonesia and Thailand. We've extended in places like Angola where it did. We'll be talking more about that over time, but right now we're really focused on project execution and delivering FGP.

Operator:

Thank you. Our last question comes from Roger Read with Wells Fargo.

Roger Read: (Wells Fargo)

Thanks. Good morning, everybody.

Mike Wirth:

Morning, Roger.

Roger Read:

I guess my first question for you with the extension of your tenure, you willing to share with us what some of the things you're hoping to get done and the extra time will be or maybe what some of the real opportunities are here that you'd like to shepherd through?

Mike Wirth: Well, Roger, it's been a pretty turbulent first part of my tenure with a major restructuring, a pandemic and oil prices that collapsed, a war and oil prices that spiked, the political and geopolitical noise that comes with those things. The ongoing climate and ESG issues. Three acquisitions, one of which we still haven't closed. I'm actually looking forward to a little smoother water, I hope, one day.

We've still got work to do to continue to drive higher returns and lower carbon. We've got good momentum in our business. We've delivered strong results through all of that turbulence and have maintained strong shareholder distributions throughout and strategic consistency throughout where we've seen others in the industry buffeted around a little bit by these forces. I'd like to continue that and to drive more value to our shareholders and higher returns and lower carbon.

Roger Read: All right. I commend you for not trying to duck out when things finally look good for at least a short time. My follow-up question is really much more on a modelling front. If we look at your realizations on oil, they were much stronger here in the second quarter. I think that contributed to some of the outperformance. What we really saw was a dip Q1, an improvement Q2, kind of back in line with traditional. I was just wondering as we think about was that a timing issue, a regional issue first quarter and anything we should be thinking about as we look at your realization or a capture on oil prices going forward?

Pierre Breber: Roger, we've not quite picked that up, so why don't you follow up with Jake after the call and make sure we understand your question. I'll give you our best take on it, but our oil realizations have looked good and our natural gas realizations have looked strong. We had better timing in the first quarter. If you look quarter on quarter, at some of our international gas, it might seem a little weaker, but not sure on liquids. Please follow-up with Jake.

Jake Spiering: Thanks, Roger. I would like to thank everyone for your time today. We appreciate your interest in Chevron and your participation in today's call.

Please stay safe and healthy. Katie, back to you.

Operator: Thank you. This concludes Chevron's second quarter 2023 earnings conference call. You may now disconnect.