2Q18 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 earnings call for the second quarter of 2018, 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 second-quarter 2018 earnings conference call. (Operator Instructions) As a reminder, this conference call is being recorded.

I will now turn the conference call over to the Vice President and Chief Financial Officer of Chevron Corporation, Ms. Pat Yarrington. Please go ahead.

Pat Yarrington (Vice President and Chief Financial Officer, Chevron Corporation):
All right. Thank you, Jonathan. Welcome to Chevron's second-quarter earnings conference call and webcast. On the call with me today are Jay Johnson, Executive Vice President of Upstream, and Wayne Borduin, General Manager of Investor Relations. We will 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. We ask that you review the cautionary statement on slide 2.

Turning to slide 3, an overview of our financial performance. The Company's second-quarter earnings were $3.4 billion or $1.78 per diluted share. This was nearly $2 billion or roughly $1 per share higher than the same period a year ago.

The quarter included the impact of a nonrecurring receivable write-down, which was offset by foreign exchange gains. A reconciliation of special items, foreign exchange, and other non-GAAP measures can be found in the appendix to this presentation.

Cash flow from operations for the quarter was $6.9 billion. Excluding working capital effects, cash flow from operations was $7 billion. The working capital penalty in the current quarter was understated by the $270 million receivable write-down just mentioned, as this was a non-cash item. Year-to-date cash flow from operations has totaled $11.9 billion, about $3 billion more than a year ago.

At quarter end, debt balances stood at approximately $39 billion, giving us a headline debt ratio of 20% and a net debt ratio of 17%. During the second quarter, we paid $2.1 billion in dividends and we currently yield 3.6%.

Turning to slide 4, in addition to the non-cash receivable write-down impact, our second-quarter cash from operations position also reflected a discretionary US pension contribution of $300 million. When these two elements are taken into account to allow for an apples-to-apples comparison, underlying cash generation improved between the first and second quarter by about $500 million. This improvement reflected higher Brent prices of about $7.50 per barrel and higher WTI prices of about $5 per barrel.

Our upstream realizations did not fully capture the quarterly increase in global oil prices, largely due to portfolio mix effects surrounding the Brent/WTI differential. We also saw lower Asia LNG spot prices during the quarter.

Year to date, affiliate dividends were $1.8 billion less than earnings. Cash capital expenditures for the quarter were $3.2 billion and $6.2 billion year to date, in line with our 2018 budget.

We had a 50% year-on-year improvement in operating cash flow from 2016 to 2017. We expect a similar improvement trajectory from 2017 to 2018. We anticipate second-half cash generation will reflect higher production, strong upstream cash margins, additional proceeds from asset sales, and some reversals of working capital requirements. These positives are expected to be offset only modestly by another discretionary US pension contribution.

Turning to slide 5, this favorable outlook on cash flow, combined with our ongoing commitment to capital discipline, enables us to initiate share repurchases targeted at $3 billion per year. Our financial priorities are unchanged. We are generating cash, surplus to what we need to meet the first three of these. We increased our annual dividend by 4% earlier in the year.

We continue to be very selective and disciplined in our investments and we have an advantaged portfolio and a large captured resource base. We plan to ratably develop these resources within the $18 billion to $20 billion capital range we previously indicated through 2020. Our balance sheet is strong and getting stronger. We will take advantage of higher price periods, like we are seeing now, to modestly reduce our debt level over time.

We will start repurchases in the third quarter. Going forward, we will provide an update at the end of every quarter on our progress. We believe annual share repurchases of $3 billion can be sustained over most reasonable price scenarios.

Turning to slide 6, just a quick update on our portfolio optimization efforts. We have previously indicated our intent to generate between $5 billion and $10 billion in targeted asset sale proceeds over the 3-year period 2018 to 2020. We remain confident in this range.

On a year-to-date basis, we have had sales proceeds of approximately $700 million, primarily from the sale of our upstream non-operated joint venture interests in the Elk Hills Field in California and the Democratic Republic of the Congo. Later this year, we expect to close the Southern Africa downstream transaction. When that happens, 2018 will be right on pace with our three-year target.

A few weeks ago, we announced our decision to market our UK Central North Sea assets. As with any transaction, we will only execute if we believe it is aligned with our strategic objectives and we receive good value.

Turning to slide 7, second-quarter 2018 after-tax earnings were approximately $2 billion higher than second quarter 2017. Special item impacts were comparable in the two periods and hence do not show up as a variance bar in the aggregate for the enterprise. Favorable movements in foreign exchange positively impacted earnings between the periods by $262 million.

Upstream earnings, excluding special items and foreign exchange, increased by approximately $2.3 billion between periods, mainly on improved realizations and higher liftings. Downstream earnings, excluding foreign exchange, decreased by about $400 million, mostly due to an unfavorable swing in timing effects; higher operating expenses, largely due to planned turnaround activity; lower Asia margins; and the absence of our Canadian refining and marketing business. The variance in the other segment, excluding special items, was primarily the result of higher interest expense, since less interest is being capitalized currently compared to the prior year.

Turning to slide 8, this compares results for second quarter 2018 with first quarter 2018. Second-quarter results were approximately $230 million lower than the first quarter. For special items, the second quarter included the $270 million nonrecurring receivable write-down, while the first quarter included a $120 million asset impairment. Foreign exchange impacts were a positive variance of $136 million between periods.

Upstream results, excluding special items and foreign exchange, were essentially flat between the quarters. Higher realizations were offset by higher operating expense and DD&A. Downstream earnings, excluding foreign exchange, improved by about $80 million, reflecting higher volumes and stronger US West Coast refining and marketing margins. The variance in the other segment largely reflected higher corporate charges and lower capitalized interest.

As I indicated last quarter, our guidance for the other segment is $2.4 billion in annual net charges and the quarterly results are not ratable. With year-to-date charges of nearly $1.2 billion, we are trending in line with our earlier guidance.

I will now pass it on to Jay.

Jay Johnson (Executive Vice President, Upstream, Chevron Corporation):
Thank you, Pat. On slide 9, second-quarter 2018 production was an increase of 46,000 barrels a day from the second quarter of 2017. Major capital projects increased production by 180,000 barrels a day as we continue to ramp up multiple projects, most significantly Wheatstone and Gorgon.

Shale and tight production increased 91,000 barrels a day, primarily due to growth in the Midland and Delaware Basins in the Permian. Base declines, net of production from new wells such as those in the US Gulf of Mexico and Nigeria, were 51,000 barrels a day.

The impact of 2017 and 2018 asset sales reduced production by 77,000 barrels a day between the periods. Entitlement effects reduced production by 54,000 barrels a day, as both rising prices and lower spend reduced cost recovery barrels.

Planned and unplanned downtime, along with the impacts from external events, reduced production by 43,000 barrels a day during the quarter. Overall, first-half 2018 production is up 4% relative to the first half of 2017.

Turning to slide 10. Second-quarter production was 2.83 million barrels per day, taking our year-to-date production to 2.84 million barrels per day. Excluding the impact of 2018 asset sales, which is the middle bar, our year-to-date production growth is 4.5% higher than the daily average production for full year 2017. This is in line with our guidance.

As Pat mentioned last quarter, planned turnaround activity across multiple locations began in earnest in the second quarter. The production impact from turnarounds in the second quarter was 67,000 barrels a day. We expect heavier planned turnaround activity in the third quarter. The production impact from 2018 asset sales was 15,000 barrels a day in the second quarter with a year-to-date impact of 8,000 barrels a day.

With the successful startup of Wheatstone Train 2, continued growth in the Permian, and ramps-up at Hebron, Stampede, and Tahiti Vertical Expansion Project, we expect production to further increase in the second half of this year. Our outlook for the full year is expected to be in the top half of our guidance range, even without normalizing for the impact of price at current levels.

Turning to slide 11, Chevron is now Australia's largest producer of LNG and the proud operator of five LNG trains with a total installed liquefaction capacity of 24.5 million tons per year. Our facilities, along with available capacity and other facilities in Northwest Australia, will enable us to monetize our world-class natural gas resource base for decades to come.

Wheatstone Train 2 achieved first production in mid-June. The ramp-up has exceeded expectations as Train 2 reached nameplate capacity within weeks of startup. We have already exported the equivalent of six cargoes of Train 2 production and we are planning to take a pit stop in the third quarter to remove the startup strainers.

Its companion plant, Wheatstone Train 1, has also been running well. The train has demonstrated nameplate capacity and has now run 195 consecutive days without a day of downtime. We also successfully completed the planned pit stop on Gorgon Train 2. The Gorgon pit stops have been successful and we are seeing improvements in performance and reliability. As a case in point, Gorgon Train 1, since its pit stop, has run more than 285 days without a day of downtime.

Combined net production from our operated LNG trains was 282,000 barrels of oil equivalent per day in the second quarter. With Wheatstone Train 2 ramping up and Gorgon Train 2 back online, we are already seeing net production approaching 400,000 barrels per day.

Let's turn to slide 12. I recently returned from a trip to Kazakhstan. Our base business at TCO is running well and the FGP/WPMP project is progressing as guided toward first production in 2022. The project is estimated to be 40% complete with preassembled pipe racks, process modules, and a gas turbine generator all in transit from yards in Kazakhstan, Korea, and Italy. Six pipe rack modules have been successfully delivered to site, demonstrating the operability of the delivery system and the receiving facilities.

Site work continues to focus on foundations, undergrounds, and infrastructure in preparation for module installation. Major mechanical, electrical, and instrumentation contracts have been awarded. We also have three drilling rigs operating on multiwell pads and drilling is ahead of schedule.

You will recall back in March that I said 2018 is a critical year for execution. This is the first year of module fabrication and site construction as well as initiation of the module transportation system. With engineering approaching 85% complete and fabrication at 40% complete, we are seeing cost pressure on the project. Site productivity remains a key driver of success for the project and is a major focus for our team.

Turning to the Permian on slide 13, Permian shale and tight production in the second quarter was 270,000 barrels of oil equivalent per day, representing an increase of about 92,000 barrels a day, up 50% relative to the same quarter last year.

Our development strategy continues to center around disciplined execution and capital efficiency. We are currently running 19 rigs and our development program is progressing as planned. While activity levels are high in the Permian, Chevron has not experienced supply shortages in the second quarter. And we are securing the dedicated crews and materials needed to execute the plan we have previously described.

We continue to focus on well performance and the optimization of our well factory. This requires coordination and planning, starting with our land position, running through the drilling and completion strategy, as well as the design and construction of facilities. And it ends with the midstream arrangements to ensure that we bring produced oil, gas, and NGLs to market at competitive realizations.

Let's turn to slide 14. We are currently operating 8 development areas and participating in approximately 30 joint venture developments operated by others. We continue to proactively manage and strengthen our land position. Year to date, we have transacted 31,000 acres through swaps, joint ventures, farm-outs, and sales.

We've previously mentioned that some of the highest-value transactions are swaps that allow us to core up acreage and enable long-length laterals. As the land transaction example on the right depicts, coring up acreage provides an opportunity to double the lateral length of each well and optimize facilities, which in turn lowers our unit development cost.

In this case, the acreage swap increased the number of long-length lateral wells we can drill by approximately 600 and improve the forecasted internal rate of return for each well by more than 30%. Since 2016, we have increased our average lateral length per well in the Permian by approximately 35%. We will continue to look for opportunities to core up acreage and improve the capital efficiency of our Permian program.

Let's turn to slide 15. Last quarter, Mark discussed the value of being an integrated company and our strategy for maximizing returns in the Permian. Chevron has secured firm transport capacity at competitive rates to move the equivalent of nearly all of our forecasted 2018 and 2019 operated and NOJV take-in-kind oil production to multiple markets, including the US Gulf Coast.

As a result of these contractual arrangements and long-term planning, this equivalent production is not materially exposed to the Midland basis differential. Our share of NOJV oil production not taken in-kind is approximately 20% of our Permian crude volumes.

We've previously mentioned that the pipeline takeaway capacity and production don't always move in perfect lockstep. There will be periods of tightness and length. As an example, in June, we had more than 50,000 barrels a day of excess takeaway capacity out of the Midland Basin, which we monetized through purchases of third-party volumes. We expect that excess capacity to attenuate through the rest of the year as our production continues to grow. Agreements are in place to access additional pipeline capacity in early 2019, in line with our production growth forecast.

In July, we utilized firm dock capacity in the Houston Ship Channel to gain access to world markets for Permian-sourced crudes. We have firm contractual arrangements in place to further increase that dock capacity in 2019. Overall, we have exported more than 8 million barrels of liquids from the Gulf Coast in 2018, further demonstrating our midstream's ability to batch, blend, trade, and export to secure the highest value for our products.

We are developing processing arrangements for NGLs and we have flow assurance for natural gas to ensure that production will not be impacted. We are moving forward with our development plans in the Permian and we do not intend to slow down activity or divert capital.

Pat, back to you.

Pat Yarrington:
Just a couple of closing comments about the first half and expectations for the remainder of the year. Cash from operations, excluding working capital, is materializing as expected, given the market conditions, production levels, and asset reliability that we have achieved.

The picture for total cash flow in the second half looks promising as well. We expect second-half upstream cash margins to improve and our 2018 projected volume increases are back-end loaded, giving us confidence that our full-year production outlook is trending toward the upper half of the guidance range. In addition, we should see some release of working capital and additional asset sales proceeds. Capital spending is on budget for the first six months.

And so in total, we have a very attractive offering for investors: a growing dividend, assets that are strong cash generators, a healthy balance sheet, and finally, sufficient free cash flow to enable a share repurchase program. In short, we are delivering on all of our commitments.

So that concludes our prepared remarks and we are now ready to take your questions. Please keep in mind that we have a lot of folks on the queue and so try to limit yourself to one question and one follow-up, if necessary. And we will certainly do our best to get all of your questions answered.

Jonathan, go ahead and open the line, please.

Operator:
(Operator Instructions) Neil Mehta, Goldman Sachs.

Neil Mehta (Goldman Sachs):
Thank you very much and congratulations on the buyback. It's great to see you making this step. I want to start there and see how you guys were framing the $3 billion number. How did you arrive at that being the right level?

And to your point about this being an every-year number, how should we think about this? Should we think of this as a base load fixed cost, if you will, on a go-forward basis in any foreseeable price environment? Or is this more of a flywheel dynamic?

Pat Yarrington:
Neil, thank you very much. Appreciate the question. In the way you asked the question, you hit upon some of the keys for us, which is we do want this [share repurchase program] to be sustainable. We obviously took a look at multiple price scenarios and we felt we could handle this [level] almost through any reasonable price environment.

We pay attention to what expectations are in the market and you can see if you look at the futures market there is a bit of a peak this year, next year, and there may be a downward trend. Obviously, that is a scenario that we took into account. And with that, we felt that the $3 billion level was sustainable.

Operator:
Phil Gresh, JPMorgan.

Phil Gresh (JPMorgan):
Yes, good morning. I echo Neil's sentiment. Congratulations on the buyback. I guess, it's somewhat of a follow-up question. You gave helpful color around cash from operations. It sounds like it supposed to be up 50% year over year, I think is what you said. And so that would be about $30 billion of CFO.

If I look at that on a post-dividend, post-CapEx basis, you'd have about $9 billion of post-dividend free cash flow. And so it sounded like you said in your prepared remarks there is also maybe some desire to pay debt down a little bit.

But just wondering how you think about that? Obviously, a third of this incremental is going back to the shareholder. But are you trying to save money for a rainy day? Or how do you think about that, considering you also have asset sale proceeds coming in?

Pat Yarrington:
Right. I think it's a great question, and you are triangulating on the numbers quite accurately. I would like to say from the start – we'd like to get the cash in the door and see it before we overcommit. So, there might be a bit of conservatism in here and how we've started.

But if you step back and think about the price environment that we are in and the price environment that may be expected, the market is telling us a lower price environment over the next couple of years may be coming, and so we think it's prudent at this point in time to strengthen the balance sheet a bit while commodity prices are high. And so we do anticipate a little bit of debt paydown over the next period of time.

We are certainly in a comfortable position from a leverage standpoint. But paying it down [debt] a little bit and shoring up the balance sheet a little bit would be an improvement and we'd have willingness to go there to a small degree.

Obviously if you are building up cash a little bit and paying down debt a little bit, it gives you a bit of an insurance policy when times get tougher to meet the commitments that you've already laid out. And by that, I mean the commitments that we put out there in terms of dividend and also now the commitment we have around share repurchases and the sustainability we hope to have around share repurchases.

They don't have the same level of commitment. Share repurchases are the fourth in our [financial] priorities. Dividend comes first. But obviously we'd like to have as much ratability and predictability around share repurchases as we can.

Phil Gresh:
Yes, that makes sense. If I could ask a quick follow-up, just on the production guidance. You're comfortable at the high end of the range, despite -- I think Jay said despite the entitlement effects, which I think in the second quarter is like a 2% year over year impact.

So maybe you could just provide some color around what do you think is going better than your expectations. Is it all Permian or are there other things as well?

Jay Johnson:
I think the primary thing that gives us confidence is that we started up Wheatstone Train 2 very late in the second quarter. It has come up very cleanly and is running well. We continue to see growth in the Permian and we have ramp-ups going on, as I said, on a number of capital projects.

We have some turnaround activity in the third quarter, which will be a bit of a drag on production. But as we move through that and as we move into the fourth quarter overall, with these new projects coming online and our relatively low-base decline, we really feel pretty comfortable about where we are on our production profile through the rest of the year, barring unforeseen events.

Phil Gresh:
Okay, great. Thank you.

Operator:
Paul Cheng, Barclays.

Paul Cheng (Barclays):
Good morning. Jay, did I hear you correctly? You are saying that Tengiz, you are seeing some cost pressure or sign of cost pressure? Can you elaborate a little bit more in terms of how big? Is that really going to be a big problem or what kind of materiality are we talking about? And where is the source of the cost pressure?

Jay Johnson:
Thanks, Paul. We are seeing some cost pressure. We are now, as I said, approaching 85% complete on the engineering. We are about 40% complete on fabrication. We are having a full year of construction in the field.

Where we have seen some cost pressure at this point in time is in our engineering program, which has cost more than we would have anticipated. We had some design quality issues, but also our productivity overall has been lower on engineering than expected. We have also seen some of our major contracts come in for field construction a little higher than what we expected.

When we put all that together, we are using more of the contingency at this point in time than we would have expected or anticipated. And so that signals that we are seeing cost pressure on the project.

We have talked about getting through this season. We really need to see how the performance goes. There are a lot of important milestones. The good things that are happening: the fabrication is really working well. We are seeing high quality from the modules themselves as they are being completed and shipped to Tengiz.

We have successfully tested the logistics system and we have delivered modules all the way to site. So those things are all working quite well.

We are 40% complete on this project. It's large, it's complex, and we've used more of the contingency at this point than we would have expected. So that tells us we have cost pressure on this project. We will continue to assess it and we will update you accordingly as we need to.

Paul Cheng:
And at what point that you will be more certain whether you have to raise your overall budget? Is it six months from now? Where is the critical path that you need to pass in order for you to know whether you will be able to stay within the budget or it's going to be higher?

Jay Johnson:
We continue to assess our performance, Paul, as we move through the project. This is a five-, six-year overall project duration. So, we are still relatively early in the project.

The site productivity is really going to be important. And as we get through this year and can really assess where we are and look at that site productivity, it is a full-court press in the field to make sure we are making progress. But in making that progress, ensuring we are using the number of man-hours and the resources that we expected.

We are very focused on the timely delivery of engineering and engineered design and bulk materials. We want to make sure that we have got our crews ready, that the workforce planning is in place, and that we have efficient support of our workforce so that we get the most out of that crew.

So, it's hard to put a definite time on it. We will continue to monitor our performance. We build these into our business plan. At this point, I do not see it impacting our guidance of $18 billion to $20 billion. And we will keep you updated as we gain more information.

Paul Cheng:
Okay. My second question. Jay, when you guys do economic analysis, do you primarily use the real price? Or are you using the nominal price as the base case?

Jay Johnson:
The real price of oil, do you mean?

Paul Cheng:
Yes

Jay Johnson:
We have a corporate price forecast which we use as our basis for our economic assumptions. But more importantly, we also test our business plan against both higher and lower price scenarios to make sure that we have a robust plan that takes into account.

The one thing we do know with certainty is that we cannot predict the oil price. So we want a plan that really is able to respond and adjust accordingly with options for whatever the price turns out to be.

Paul Cheng:
I'm sorry that I probably didn't make myself clear. When I say real price, means that the price adjusted for inflation. Do you build in an inflation factor, whatever is the price deck that you use? Or you just use a nominal flat price in your assumptions?

So when you guys previously saying that Tengiz would be a $60 or low-$60 Brent price would be generating a 10% return or 15% return, is that the price based on inflation adjusted or nominal?

Pat Yarrington:
It's based on inflation adjusted. We look at what we expect prices to be because the cost estimates that we are putting together have those kind of components built in. But when we are taking the project to evaluation, when we are doing the final investment decision, we look at a whole host of price scenarios and we look at both nominal and real outcomes.

What would you have to believe to have a 10% rate of return in a nominal sense? What would you have to have in a real sense? So we look at the economics and judge the value of the projects based on multiple price scenarios. But when we are actually putting out an FID number, it is our best estimate of what the cost at that point in time will be.

Paul Cheng:
All right. Thank you.

Operator:
Doug Leggate, Bank of America Merrill Lynch.

Doug Leggate (Bank of America Merrill Lynch):
Thank you. Good morning, everybody, and thanks, Jay, for getting on the call. I've got two questions, if I may. I guess the first one is an upstream question.

When you laid out the Analyst Day back in March, obviously you kept your guidance through 2020. And if we take, Pat, what you said about the buyback being sustainable, it seems at least on our numbers in the current oil price environment you have got a lot more headroom in terms of surplus cash.

But I'm curious, what are your intentions post 2020? Should we expect the current level of spending to be sustained? Or is that headroom to allow for, let's say, another step-up in project visibility as we go beyond, for example, Tengiz as we go beyond 2020? I've got a quick follow-up, please.

Pat Yarrington:
Doug, I think I would just start and say we feel good about the $18 billion to $20 billion range out through 2020 because we can see our way forward with the quality of the resource base we have, the production profile that we've laid out for the Permian and other unconventionals, our ability to take what is a relatively less mature asset base like LNG and debottleneck it and see continued value growth there.

We have a whole series of investments that we can see lined out that our current portfolio gives us opportunity to develop economically. And that is why we feel comfortable about the $18 billion to $20 billion range.

When you get beyond 2020, we really will have to have a review of other incremental projects that we would like to bring online. At some point, we believe that there will be the opportunity to add deepwater investments, for example.

Those are competing now or they are working to get their cost structure down so that they can compete better in the portfolio. That time that will come. We've said in the past that we want to be ratable in terms of how many [projects] we bring on during what time frame and what sort of pacing we do.

So those are all things that we will put together as we are looking at our 2019 to 2021 plan. And it's all information that we will try to come out and provide a little bit more guidance for when we get to our security analyst meeting in March of 2019. But for now, I think the key message is: $18 billion to $20 billion, that's the capital program, that's the capital discipline that we are living within.

Doug Leggate:
Thanks, Pat. Jay, maybe I can follow-up with you specifically then on another potential source of cash. Because you guys have obviously got tremendous flexibility with the Permian, but you are also very early in your $5 billion to $10 billion disposal plan.

And since you laid that out, the oil price has obviously recovered quite a bit. So I guess what I'm asking, Jay, is there upside to your disposal target? How has the change in oil price changed your view of what's core within the portfolio? And I will leave it there. Thanks.

Jay Johnson:
I would say that as we look at assets that are going to be part of our divestment portfolio, we tend to look at assets that are approaching end-of-life or very early in life. Early in life would be resource opportunities that we have that just don't compete for capital in the portfolio.

They may be quite economic, but they don't compete for capital. We are trying to be very disciplined about what projects we invest in and only invest in the top part of our queue.

The projects that are very late in life tend to have limited resource potential left for us and those are the ones we are putting out there. The higher prices certainly help, but I wouldn't change our guidance at this point in time.

This is going to be a pretty ratable program. And it's a normal part of our operation to continue to look at properties as they move through their lifecycle and decide when do they need to exit the portfolio. Our overall focus on all of this is we are not driving to a production target. We are driving to improve our returns and lead the industry in returns for our upstream assets.

Doug Leggate:

Appreciate you taking my questions, guys. Thanks.

Operator:
Jason Gammel, Jefferies.

Jason Gammel (Jefferies):
Hi, everyone, and thanks very much. Jay, it's very positive comments on the operations in Australia essentially reaching nameplate capacity already. And obviously, very long duration runs on several of the trains.

I guess my question is given this performance, how should we think about utilization rates in 2019 on the LNG facilities, recognizing that obviously some maintenance still needs to be done? But that there are probably some debottlenecking opportunities in the near term that you might be able to take advantage of?

Jay Johnson:
We have not issued any formal guidance yet. We are going through the business plan now when we really develop that guidance. I would say that we took the learnings from Gorgon Train 1 maintenance and applied those to 2 and 3. We've now gone through this period of pit stops. We are comfortable with where the Gorgon trains are at this time.

We need to have some runtime and do the analysis to see where opportunities exist for further expansion. One of the best ways to extend the capacity of these trains, of course, is just keeping them fully online and fully utilized and that's our primary focus at the moment.

Wheatstone is a very similar story. Train 1 had a pretty clean startup. Train 2 has started up very cleanly, and at this point in time, we don't anticipate taking either train down [beyond required Train 2 startup strainer removal].

If we see economically driven opportunities to enhance performance, we may have some small pit stops from time to time, similar to what we have done previously. But overall, other than routine maintenance, I think a lot of the known shutdowns are behind us.

We will get into a regular rotation of shutdowns, as all major trains do. And that is on a three- or four-year cycle. We want to have them staggered out. But that's all being sorted out in our business plan and for now we would expect to see some pretty good sustained runs on these trains.

Jason Gammel:
Okay, thanks. That's very helpful. And then just as a follow-up. Jay, could you comment on timing on first production at Big Foot and whether you are actively engaged in restarting production in the PZ?

Jay Johnson:
Yes, so at Big Foot, we still expect to see production started later this year. We have made good progress. We got the platform successfully installed and storm safe, as you know, early in the first quarter of this year.

The drilling program is underway. We are completing the first wells and we are just about to bring gas into the facility to start the final commissioning. Later this year, we expect to see production at Big Foot. In fact, we've already run some of the second riser just to make sure loop currents aren't a factor for us in that program.

As we look at the PZ – that, of course, is an ongoing issue that the two governments are working to resolve. Our focus is on making sure that we are keeping the facilities in a ready-to-restart mode. We are very focused on asset integrity and preservation types of activities.

We have also done a lot of engineering and used this downtime to model not only a more comprehensive reservoir set of models, but also the surface facilities. We really identified all the opportunities of low-hanging fruit to optimize the flow once we get the facilities back online.

So I think there is a lot of good opportunity for us when it restarts. We remain ready to go, and of course, we will support the governments as they work towards resolution.

Jason Gammel:
Thanks very much.

Operator:
Roger Read, Wells Fargo.

Roger Read (Wells Fargo):
Yes, good morning. If we could, Jay, maybe come back to the Midland Delaware Basin, the takeaway. And then you've been over the last several quarters exceeding the guidance range that was laid out at the Analyst Day. So I was just curious, as you think about the capacity to take away, both on the oil and gas side, the fact you are running ahead of the guidance range, does that create any risk?

And then the second part of my question is as you move nonoperated or non-produced barrels, that 50,000 barrels a day, and replace them with your own, how does that flow through in terms of performance? I would assume better cash capture, cash margin capture, on your own barrels than third party, but I was just curious how that works out.

Jay Johnson:
I will take the first part of the question. The higher production that we are seeing from our operations is taken into account. Our midstream group and our [midcontinent] business unit are in daily conversations about what our updated [production] forecasts look like so that we don't catch anyone by surprise. The midstream group has done an outstanding job of working with various suppliers of services in the area for our takeaway capacity.

Our focus is on maximizing returns from the Permian and that's what drives all of our efforts. So where we have had opportunities to contract for service rather than investing our own capital for pipelines, takeaway capacity or gas lines – things where we can tariff through – we have chosen to do so. But that means we have to be very coordinated with these various suppliers to ensure the capacity is in place and accommodating our growth plans.

At this point in time, we look very good through 2018 and 2019. We will continue to monitor this. There are periods of tightness and periods of excess capacity. And we look to take the opportunity to acquire other crudes and move them through those lines when the opportunities present themselves in the form of a differential exceeding the tariff.

When we consider the NOJV [production], you almost have to think of the upstream producing [and delivering] into the Midland area. And then our midstream takes crude from the Midland area and moves it to markets. And that's our crude and others' crude.

So it's really a big machine, but it's hard to say how one specific barrel moves through the system. It's more of a commercial arrangement and equivalent volumes. Our goal is to make sure that we are getting the maximum returns for the barrels that we produce, whether they are non-operated or operated barrels as we move barrels to the various markets.

The other thing our midstream has done that's been really helpful is not just secure pipeline capacity out of the basin to the various markets, but they have also made arrangements so that we can move barrels across the dock into ships and access world markets. So, we can evaluate those markets and adjust our offtake as needed to maximize our realizations.

Roger Read:
Great, thank you.

Pat Yarrington:
And I would just add that's one of the benefits of being an integrated company. It's also one of the benefits of being a company that focuses on a longer-term plan. We have been under this plan of a 20-rig rate in the Permian for quite some time and all of these precursors have been lined out.

Roger Read:
Thank you.

Operator: Theepan Jothilingam, Exane BNP Paribas.

Theepan Jothilingam (Exane BNP Paribas):
A couple of questions, actually. Firstly, I think you gave guidance at the Analyst Day on the headwinds in the cash flow of somewhere between $2.5 billion to $3.5 billion. So I just wanted to know whether that guidance is still valid and how much of that -- those headwinds have been consumed in the first half.

And then the second question. I think we've been given an update in terms of the unconventional business, particularly for the Permian. But I was just wondering how the rest of the unconventional business -- the Duvernay Argentina -- is looking as one reviews the last six months. Thank you.

Pat Yarrington:
I will take them in order. So yes, good question about the headwinds. Year to date, through the first six months, we are sitting at combined headwinds of about $3.6 billion. The guidance that I had given back in March was between $2.5 billion and $3.5 billion. I think that is still good guidance. [The headwinds], in fact, may come in a little bit towards the low end of the range.

What we are seeing here with higher prices is that the deferred tax headwinds that we thought would materialize at lower prices are essentially turning into a tailwind at higher prices. And that's exactly what you would expect. So, bottom line, somewhere between $2.5 billion to $3.5 billion, but probably closer to the bottom end of that range.

Jay Johnson:
And as far as our other unconventional activities, we continue to see very good progress in all three of the assets. I will just walk through them one at a time.

We've increased from two to three rigs down in Argentina. We work very well with our operator YPF. We are seeing continued improvement in our performance down there. The economic returns are looking very strong.

I think what is really important in Argentina – as they continue to deal with their situation, is ensuring that they maintain an open market, which will be an important watch point for us as we continue to move forward with our operations in the Vaca Muerta.

We also have a field called El Trapial, which was a conventional field up in the northern part of the Vaca Muerta. And we are planning to do an eight-well pilot for the unconventional potential under El Trapial. There is a lot of expectation that this may also prove to be a good area for us from an unconventional sense.

We have restarted our drilling campaign in the Marcellus. We took a couple-of-year holiday just to reduce our capital during the last couple of years, but we are now moving back into operation there. The initial results coming out of the Marcellus [are encouraging], as we've picked up right where we left off and continued our march toward lower unit development and operating costs. So we're pretty pleased with what we are seeing in the Marcellus and Utica areas.

And then finally, at Kaybob Duvernay in Canada, we are also seeing good performance from our crews up there. We have moved from largely a land tenure and assessment or appraisal drilling mode into our first factory mode and have our first development area. That is about 55,000 acres that we started on in November of 2017. As we shift from moving rigs around in appraisal drilling to development drilling, we expect to see continued improvement in performance there.

One of the things that has been really successful for us over the last two or three years has been bringing these various teams together. They meet on a regular basis; best practices are shared between the different areas.

So while they all have different characteristics, there is far more in common than there is different. And the techniques, the best practices, the use of data analytics, the experience that we gain on a daily basis, instead of just being applied to area, we are deploying that across all four.

And it doesn't just flow from the Permian outward. Things like zipper fracking actually came from the Marcellus into the Permian. We see that leveraging knowledge and experience is quite powerful and very valuable for us.

Operator:
Pavel Molchanov, Raymond James.

Pavel Molchanov (Raymond James):
Thanks for taking the question. As you are working to expand Gorgon, I know that the Australian government is prioritizing more domestic gas supply, particularly for the eastern states in the country. And how do you kind of balance out your higher export demand with the fact that there is a brewing shortage domestically in the market?

Jay Johnson:
Well, we would love to sell them LNG to start with. But what's really important to Australia, as with any country, is energy security. You always want to make sure your country has sufficient supply of clean, affordable, reliable energy source.

And so in the West Australia, there is no pipeline; there is no way to transport gas from the West to the East other than through LNG. We continue to produce LNG. We have extensive gas resources in the West: 50 trillion cubic feet of gas that's Chevron equity gas.

We have domestic gas plants at both Gorgon and Wheatstone. We have plenty of capacity to supply the West Australia market. But we also are really focused on making sure that we move and monetize that gas resource to the various markets that are demanding it. So at this point, I don't see the East Coast problems having any impact on either the expansion or the delivery from West Australia.

Pavel Molchanov:
Okay. A quick follow-up on your monetization plans. You mentioned some of the upstream assets. Given the very hot demand these days for Permian midstream capacity, is that something that you would consider including in your divestment planning?

Jay Johnson:
We don't really have midstream assets per se in the Permian area. We have been focusing on the upstream; that is where we see the highest value, the highest returns. And our takeaway capacity in midstream processing, like gas plants, NGLs, is provided by third parties.

Pavel Molchanov:
Okay, understood.

Pat Yarrington:
Okay, thank you very much. I think that concludes the queue here. So I guess we are ready to end the call. I'd like to thank everybody for your time today. We certainly appreciate your interest in Chevron and we appreciate the questions that came in. Thank you very much.

Jonathan, back to you.

Operator:
Ladies and gentlemen, this concludes Chevron's second-quarter 2018 earnings conference call. You may now disconnect.