Neptune Energy Q1 2019 Results Conference Call

Presentation

Jim House

CEO

Alright, thank you, Molly. Good morning everyone, and welcome to our earnings call for the first quarter of 2019, covering the period up until 31 March. I just briefly want to let you know, we may be interrupted due to an unplanned fire alarm test that just triggered, but we're going to continue with the call.

Before we start, just a reminder that we draw comparisons to Q1 2018. We use proforma numbers based on one and a half months of Neptune ownership, and one and a half months of EPI reflecting our completion of the Engie EPI International acquisition on 15 February 2018.

Turning first to the overview of slide 4, importantly our health and safety performance continues to improve across all our countries. When compared to our final quarter of 2018, our total recordable incident rate improved, by declining from 2.6 to 1.94 per million man-hours worked, including our joint venture activities.

In the first three months of 2019 we produced an average of 151,800 barrel oil equivalents per day, reflecting lower production as expected from Norway, offset partly by higher production in the UK. Production in the Netherlands and Germany remains steady. It was also encouraging to see further improvement in production efficiency across the Group, which rose to 91% during the period.

For the full year, we expect production to average around 155,000 barrel oil equivalents per day, with the second half seeing the benefit of the Touat development project in Algeria reaching plateau, after coming on stream - we will speak to that in July - plus three in-fill wells at Fram. As a result, we expect to end the year at a higher rate than the average we posted in 2018.

We also continue to make good progress on operating costs, with OpEx per BOE falling to $1.10 per BOE in Q1, and we expect further progress across cost-reduction plans which are underway in Germany, the Netherlands, and France.

Moving to our financials, we realised an average oil price of $58.50 per barrel, and a gas sales price of $6.50 per 1000 cubic feet before hedging, resulting in revenues of $621 million. Operating cash flow was $362 million, and EBITDAX came in at $451 million.

Turning to the operations update on slide 5, we produced 72,200 barrel oil equivalents per day in Norway during the period. As expected, this was lower than the previous quarter due to natural field declines at Gjoa and Gudrun, plus two unplanned shutdowns in the non-operated Snohvit field, plus minor periods of production curtailment at Gjoa.

Our continued focus on optimisation efficiency helped maintain operating costs flat at $7 per BOE, and we expect further savings from logistics and transportation to come throughout the year.

In the Netherlands, production was 25,700 barrels of oil equivalent per day, which was slightly higher than the last quarter of 2018 as a result of higher production from G16 offsetting the unplanned shutdown at G14B. Operating costs for the period were broadly flat at $12.10 per BOE. We have also initiated a cost-savings program in the Netherlands targeting a $5 million per annum reduction in G&A.

Production from Indonesia was 20,000 barrels of oil equivalent per day, which was slightly lower than the prior period as Jangkrik came off plateau, which was expected at the end of 2018. Jangkrik had maintained production rates of 700 million standard cubic feet per day, compared with the original 450 million planned for the original field development plan.

To help maintain stable OpEx rates in Jangkrik, one in-fill well and one workover had recently been completed this year, with a further in-fill well currently under drilling operations.

In the UK, production increased around 20% to 16,700 barrel oil equivalents per day, mainly due to fewer third-party restrictions downstream at Cygnus, and operating costs were maintained at $6.90 per BOE. Restrictions at Cygnus currently constrain the field typically at 265 million standard cubic feet per day, although we have posted production of 320 million cubic feet per day when downstream fields are offline.

Production in Germany was stable at 12,800 barrel oil equivalents per day, reflecting good production management and operating efficiency. Operating costs in Germany, excluding well fees, were $22.60 per barrel equivalent. We have a target to reduce these costs by 10% this year and are making good progress. Further cost savings are expected to be realised next year as well.

In North Africa, we produced 4400 barrels equivalent a day, exclusively from Egypt. This was broadly flat on the prior period, and OpEx costs remained stable at $9.50 per BOE. Of course, we expect significant production growth in the North African portfolio with Touat coming online late June, early July, and plateauing in early Q3.

Turning to development and exploration on slide 6, we continue to make good progress on our projects with all developments progressing on time and on budget. The first of these to come on production, as previously mentioned, is Touat in Algeria. This is a significant development for us which will provide 26,000 barrel oil equivalents per day on a working interest basis.

The facility received first gas into the plant from mid-February, and we’re now in the final stages of commissioning. We do expect first gas export by the end of June, followed by a quick ramp-up to production plateau. Along with the three multilateral in-fill wells we're drilling at Fram, Touat will be the biggest contributor to the Group's production in the second half.

In Norway, we're making good progress with our operated Duva and Gjoa P1 projects, and in March we awarded the rig contract. Development drilling in Duva will begin in the fourth quarter, with further drilling on our operated Gjoa P1 planned early next year. Our operated Fenja project also remains on track for the first production in 2021. We have key contracts in place and expect to commence drilling in the first quarter of next year.

The non-operated Njord project, the host for Fenja, remains on course for first hydrocarbons by the end of 2020.

In the UK, we're making progress with our operated Seagull project, and expect to award the drilling contract in the second half of the year, with the first production still expected in first quarter 2021. On a working interest basis, the total of these new projects will contribute around 90,000 barrel oil equivalents a day of new production.

In exploration, we have initiated working on our four operator licences which were awarded in Norway. We plan to drill Sigrun East and Echino South prospects later this year. In the UK, we now expect to spud the Isabella prospect in the third quarter, ahead of schedule, and drilling operations begin at Darach this month. In Germany, well-deck construction on Schwegenheim has commenced, and is due for completion in July with a planned spud date later in the third quarter.

In Egypt, we began drawing the Karam 10 development well during the second quarter and finally, in Indonesia, we expect to spud the Geng North exploration well towards the end of the year.

With that, I will hand over to Armand to take you through the financials.

Armand Lumens

CFO

Thank you, Jim, and good morning, everyone. Looking at slide 8, the weaker commodity price environment was the primary driver for our Q1 2019 financial results which, while lower than comparative periods, were nevertheless a positive achievement leaving us well placed to pursue our strategic objectives. As a reminder, we completed the acquisition of Engie E&P International on 15 February 2018, so our financial figures, unless stated as proforma, reflect the performance of those assets since this date. We also completed the acquisition of VNG Norge on 28 September 2018.

In Q1 2019 we generated revenues of $621 million. Revenues were impacted by the fall in average realisations compared to Q4 2018, and to a lesser extent the near-term decline in Group production mentioned by Jim already. The fall in commodity prices was partially mitigated by our hedging activities, which we will talk about later.

Operating cost in Q1 averaged $10.10 per barrel, and was marginally lower than the $10.20 per barrel we delivered for 2018 as a whole. We continued to focus on cost control, and we have implemented programs targeting reductions in operating and G&A expenses in Germany, the Netherlands, and France.

For the full year, we reconfirm our guidance that the unit operating costs will remain broadly in line with our performance in 2018. EBITDAX for Q1 2019 of $451 million was lower than the Q4 2018, principally driven by lower realised commodity prices during the period. Net income for Q1 2019 was $53 million, with an effective tax rate for the period of 74%.

Good operating cash flows of $362 million enabled us to invest $156 million in our projects in Q1 2019 and deliver a $151 million reduction in the net debt to $1.44 billion. This gives us the flexibility to grow and deliver our strategy. Our net debt to EBITDA ratio was 0.67 times, and 0.64 times on an EBITDAX basis, both of which remain well within the desired levels and continue to trend lower.

Slide 9 shows how significantly commodity prices have fallen since the last quarter of 2018. On a pre-hedge basis, both oil and gas prices have fallen by approximately 18% and 26 % respectively, with oil realisations averaging $58.50 per barrel of oil equivalent, and gas prices averaging $6.50 per thousand cubic feet.

We currently have hedges in place for 43% of our crude oil sales and 63% of our dry gas for the remainder of 2019. For 2020, we have 19% of oil hedged, and 54% of dry gas hedged, leaving us well placed to capture the benefits of the recovery in oil prices. Please note that these percentages quoted are post-tax sales volumes.

Turning to our cash flow summary on slide 10 now. Despite the weaker commodity price environment, lower operating costs and cash taxes in the period enabled us to deliver a strong cash flow generation in Q1, with a post-tax operating cash flow of $362 million. Cash taxes of $71 million represented 16% of pre-tax operating cash flows.

Development and exploration CAPEX for Q1 was $156 million and was largely weighted towards our projects in Norway. This excludes a further $15 million of cash we invested in our Touat project, which is accounted for using the equity method as a joint venture.

Due to project timing, CapEx was lower than our full-year run rate, and we reiterate our guidance of $700 million capital investment for 2019.

Turning to slide 11 and our balance sheet now. Our strong cash flow generation has enabled us to continue to de-leverage during the quarter, reducing our outstanding gross book value debt by $177 million to $1.6 billion at the period. Our net debt at the end of the period was $1.4 billion. We now have $746 million drawn under our own RBL, $550 million senior notes, a $109 million vendor loan with Engie, and a $218 million in project financing related to our Touat project.

It’s important to note that the project financing is repayable from project cash flows only, so has no recourse back to Neptune, and other debt instruments are long dated, with maturities in either 2024 and 2025. At the end of the year, we also fixed 76% of our debt portfolio.

We have recently renegotiated the terms and conditions of the RBL facility, which will deliver both cost and efficiency savings. The RBL margin has been lowered by 75 basis points, delivering savings of more than $7 million per annum, and scheduled redeterminations are now reduced to once a year only.

The overall debt capacity Neptune is permitted has been increased, and the first scheduled amortization has been postponed by one year. We believe this is a really positive recognition of the operational and financial progress made in the past year, and these achievements have also been recognised by Moody's, which has put us on a positive outlook, and Fitch, which has assigned Neptune a BB first time rating.

Moving on to our financial position on slide 12 now, this shows, that net of cash of $171 million, our net debt position was $150 million lower than at the end of 2018. At the end of the period, we had close to $1.2 billion of available headroom under the RBL which, when combined with our cash position, gives us a liquidity of more than $1.3 billion.

In summary, we achieved a robust financial performance in Q1, and we were able to continue de-leveraging our balance sheet despite substantially weaker oil and gas prices in the period. Our financial position will strengthen as production increases in the second half of 2019 and we can realise the benefits of the higher oil prices we are now seeing.

And with that, I'll hand back to Jim for the outlook.

Jim House

CEO

Alright, thanks Armand. Turning finally to the outlook on slide 14. As I said at the beginning of the call, we expect production for the full year to average 155,000 barrel oil equivalents per day. With the contribution of Touat coming on stream, and with in-fill wells at Fram, we remain on course to exit the year at rates well exceeding our 2018 average.

As Armand has shown, we delivered a positive Q1 2019 financial performance, and retain a disciplined approach to investment and operating expenditures, with guidance for both remaining unchanged. The reduction in net debt and our revised RBL terms is supportive to delivering the strategy we outlined in our full-year financial results just a few weeks ago.

We remain confident in our business, leaving us well positioned for additionally organic and inorganic growth, with a strong outlook for both production and project development.

With that, I'll pass the mic now to the operator for questions. Thank you.

Q&A Session

Robin Haworth, Stifel

Hello? Excuse me, excuse the delay. Just a couple of questions, if I may. First one on the Technip global alliance that you signed recently. I was just wondering how that looked in practice, and how does that work? Does that involve Technip staff getting involved in your projects early in the design stage? Does that mean that you'll still put projects out to tender, or will you essentially be bringing Technip in-house?

Jim House

Okay, thanks Robin. Great question. Obviously, this Technip global alliance is a very important contract for Neptune in north-west Europe. To answer a couple of your questions, first off, Technip's been aligned with us even before we signed the contract, and we were doing some pre-engineering work, but it provides synergies for us in Norway, the Netherlands, and in the UK. You'll also find it helps us to standardise the equipment we're using, because many of our installations already have TechnipFMC-type equipment.

There's a balance to be struck with how reliant we'll be on Technip, but we've been very impressed with the new company that's emerged with the combination of Technip and FMC, and we've got extreme confidence in their abilities, and they're willing to actually take a few risks with us, and obviously benefit from superior performance.

But we're very pleased. There's a balanced approach. We've got our own in-house expertise that couple with what they can provide, and we are aligned with them on virtually all of our major projects in the North Sea.

Robin Haworth, Stifel

Okay, that's helpful, thanks. Just a question on Snohvit and the downtime it saw in Q1. I'm just wondering if you could elaborate a bit more on that. Is that a problem - a mechanical problem? Is that a sub-surface problem? Is that something that you have been able to get on top of and fix, or not?

Jim House

Okay, another good question. Snohvit, obviously a major part of our portfolio. I'm sure you'll know, it's operated by Equinor, who was formerly Statoil. They had two isolated events, neither of which are sub-surface. In fact, reservoirs are performing as planned, and there's a rate plateau that's behind it. We've also sanctioned another development there called Escalade that will supplement that of Snohvit.

So, the two downtime events were operationally related. One was due to a seal failure on a CO_2 recovery unit. The other one, that came actually from in-house engineering designs, they decided they needed to do additional installation and heat-tracing of parts of the processes. So, they, on purpose - although it wasn't planned coming into the calendar year - took the plant down for about a week to install heat tracing to keep things, obviously, from not freezing up, and additional installations.

So, both were unplanned, although one was instigated on purpose. But it's back up and running and running very well.

Robin Haworth, Stifel

Okay, very clear, thank you. The final one. You mentioned the Touat project getting to plateau in H2. How long are you thinking about that staying on plateau? Is that - I imagine, as a gas project, that's a relatively long plateau.

Jim House

Right. So, the project itself was sanctioned for a plateau in the range of eight to nine years. They drilled the first batch of wells, which are 19 wells, and last year they went for extended rounds of well testing and extended well tests and have done analysis of this work. What they found, and what was determined, is that actually, the well performance, we've got 50% more deliverability from the well stock than was originally planned, and these wells are actually seeing larger parts of the reservoir, which means they'll have larger recoveries.

So, the original plan was to have a plateau of eight to nine years. There's this phase two which we may be able to defer, because the fact is that the initial impression from the well tests show that these wells actually have more horsepower than what was incorporated in the design plan.

So, as we mentioned, the first gas went into the plant in February, live hydrocarbons in to power the power generation systems as well as test all the various components of the gas processing plant, and the outlook is, sometimes during the second or third week of June, as we stand, that they could be in a position to start exporting gas, and we anticipate a ramp-up to the nameplate capacity of the plant in July, and with most plants there additional room, and once we get the plant up and running, and running stable, then we'll look at ways to tweak how the plant operates, with an ambition to squeeze out more than what the plant was originally designed for.

Robin Haworth, Stifel

Excellent, that's very helpful. I'll leave it there, thank you very much.

Jim House

Alright, thanks Robin.

Daniel Vaun, JP Morgan

Hi, just semi-related to the Snohvit issues. If you look at that asset coming back online, the UK is running better than we had thought, and then other assets coming on-stream over the course of the year, that 155,000 production guidance looks to actually be a bit too low for the full year. Just wondering where - what prevented you from upgrading that, because it looks as though that's likely to be beaten by a strong performance in both the third and fourth quarter. Thank you.

Jim House

Well, Daniel, I like your optimism. We just went through our monthly outlook and yes, we've got a range, and you might argue that we're guiding to the lower part of the range. There's a few things in the portfolio right now that look like they'll be delivered sooner with better rates. We have not factored that into our internal outlook, nor are we guiding to it. But there is scope to improve on the number.

So, we know - you've seen what we have for the first quarter. We will have second quarter numbers later in the year, and once we're in a position to guide higher we'll certainly do that. But it looks like you know how to put all this back together, I guess. I like your outlook.

Daniel Vaun, JP Morgan

Thank you.

James Hosie, Barclays

Hi, good morning. Just a question on your organic growth acquisition plans. I was just wondering what your latest thoughts are on how attractive the asset market looks to you, particularly your focus on high-quality assets, and then are there any particular regions where you feel you're being priced out by competition.

Armand Lumens

Yeah, I'll be happy to answer this one. We are, let's say, continually scanning the market for mergers and acquisitions, but we have done quite a number of good deals in 2018 in terms of the acquisitions we did, which were mainly small bolt-on acquisitions with the VNG and Isabella and Seagull assets. So, we know that those smaller deals are a bit easier to integrate, and probably also more valuable to the portfolio. So, we continue to scan those, but there's not anything on the immediate horizon that would be added to the portfolio.

In terms of your point on competitiveness, yes, it's a very competitive market, and we've seen, as you have seen that as well, quite a lot of activity, including in the North Sea. We at some point have also looked at various packages and portfolios, and coming back to my earlier point on smaller, bolt-on acquisitions, the bigger packages are not as easy to integrate into our existing portfolios, and that's why they were probably also scooped up by others in the market.

It is extremely important for us to state that whenever we look at them, and whenever we would consider those, we want to stay cool-headed with regards to these opportunities, and only do these acquisitions if they make sense and add value to the shareholders.

Jim House

If I could add to Armand's comments, we are in a somewhat privileged position because we've got such a deep portfolio with growth opportunities, and we talked about the ones that are already sanctioned that are going to add 90,000 barrels a day already over the next couple of years. So, we can be patient, but you can see from our balance sheet we've got the capability of doing something that would add materially to the portfolio.

Yes, we're looking. We look at most things that would potentially make sense, but they've got to be accretive to a variety of elements of our portfolio. Some markets are more competitive than others. I think you know which ones those are. But we remain steadfast in delivering on our portfolio while looking for the right opportunity.

Armand Lumens

Yeah, and M&A is obviously only one of the tools that we can use to grow, and we continue to focus also on exploration, that will obviously be a longer-term effect, and also obviously running our assets well, and delivering our projects. So, M&A is only one of the three possibilities to ensure growth, and we want to make sure that we do this in a balanced way.

Jim House

If you look at the bulk of our portfolio, during the latter stage of Engie's time it was more about delivering major projects, and that included Cygnus, Jangkrik in Indonesia, and Touat which we obviously saw the last 18 months of that project. They were arguably very light on drilling and exploration, and we've rebuilt the portfolio, and we've got a handful of very attractive wells being drilled this year, as well as into '20 and '21, that could meaningfully move how we look in the various countries that we operate.

James Hosie, Barclays

Okay, thanks very much. Note taken on your focus and I think other than M&A as well. Thank you.

Armand Lumens

Thanks, James.

Emily Morris, Numis Securities

Hi, good morning. A question on exploration. It's exciting to see you guys really getting going in the second half of the year. What overall scope of resources could be added? It's just not quite clear to me the combination of what you're going for. In terms of the prospects you're drilling, which ones should we perhaps particularly focus on in terms of substantial potential additions to resources?

Jim House

Alright, great question. Near-term, in Norway, we've got two wells, Echino South and Sigrun East. Both are non-operated. Lower risk, but lower reserve profile for us. Isabella's large. We've got 50% interest in that. Darach is medium range, a little bit more risk as well. We've got risk-adjusted numbers, so they cloud what the real upside potential is. Add it all up, we're looking at things that are in the 100 million to 200 million barrel-type range, [rest], and then with a bit of success, obviously that number grows.

That's the near-term portfolio, and we're working internally to work on what is our real resource potential, and we've got a project that's between our [original] engineering group and our exploration group called Val Nav, and they're cataloguing all of the opportunities that we have in our database and within our inventory, and we'll have an upgraded portfolio, as well as how we do our capital allocation, going into 2020.

I doubt - that's a great question, and without adding them all up it's hard to give you a clear answer, but let's just say this. You could probably - with a bit of success, we could more than replace production several-fold this year.

Emily Morris, Numis Securities

Great, thank you.

Julien Laurent, Natixis

Hi, hello, thank you for taking my question. I was wondering if you can give us any feeling about the inflation potential coming back in the sector, particularly on drilling. Could you quantify the cost savings that agreement you have with Technip can generate for you in terms of return? Is it significant, or is it just a way to have a smooth relationship with your supplier? Thank you.

Jim House

Right. Julien, that's a great question. I'm not sure we'll have all the detailed answers, but first off, from the inflation piece, you pick which geo-market you're in and it's slightly different. We did see a bit of increase in inflation in the Norwegian market, which may have stagnated in terms of the rate of increase. UK market seemed reasonably good, and some of the rig rates we're looking at potentially from Seagull are very reasonable. We're in, I think, in a very good place. North Africa's always been a market that's different and at lower cost, and Indonesia seems to be pretty flat.

So, the only place we've seen moderate inflation over the last 18 months has been in Norway, but that seems to have flattened out.

Giving a clear answer on TechnipFMC and the contract, obviously we've got an eye on value creation. There are cost synergies in the contract, and we'd have to go and do a deep dive on each and every project, but obviously they have the best cost benefit and value creation answer for us compared to their competitors, and they bring a composite group of services, everything from trees and well-heads and valves to sub-sea-type equipment, including installation.

So, they were the right answer for Neptune, and we're early in the journey together. But it's a new company that's about two years old since they merged together, and they've got all the right ingredients for what we want to deliver our projects.

Julien Laurent, Natixis

Thank you.

Jim House

Right. That was a great list of questions, and we do appreciate your time to dial in and listen to our first quarter earnings call. I think we're very positive about the outlook for the business. If you look at our organisation, we've gone through a year of change last year, and we're really starting to see the dividends from building out a new management team and going to the new organisational structure that's leaner, that's taken out the unnecessary stuff from making decisions. It's bearing through in our cost profile and our operating efficiencies. So, I think everyone's feeling a real sense of energy within the Neptune family.

With that I'll close the call, and if we don't see or talk to you before, have a good summer. We look forward to talking to you again, and presenting our numbers at the end of August. Have a good day.

Armand Lumens

Thank you.

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