HUSKY ENERGY

SECOND QUARTER 2017 CONFERENCE CALL AND WEBCAST TRANSCRIPT

Date: **Friday, July 21, 2017**

Time: **9:00 AM MT / 11:00 AM ET**

Speakers: **Robert Peabody**

President and Chief Executive Officer

Jonathan McKenzie

Chief Financial Officer

Rob Symonds

Chief Operating Officer

Dan Cuthbertson

Director, External Communications and Investor Relations

OPERATOR:

Welcome to the Husky Energy Second Quarter 2017 Conference Call and Webcast. As a reminder, all participants are in listen-only mode and the conference is being recorded. After the presentation, there will be an opportunity to ask questions. To join the question queue, you may press star, then one on your telephone keypad. Should you need assistance during the conference call, you may signal an Operator by pressing star, and zero on their telephone.

I would now like to turn the conference over to Dan Cuthbertson, Director, External Communications and Investor Relations. Please go ahead, Mr. Cuthbertson.

DAN CUTHBERTSON:

Good morning, and thanks for joining us. I'm here with CEO Rob Peabody, CFO Jon McKenzie, COO Rob Symonds, and other members of our Senior Executive Team. We will provide an overview of our second quarter results and then open up the lines for your questions.

This call will include forward-looking information. The various risk factors and assumptions are listed in this morning's news release, on our website and in our annual filings on SEDAR and EDGAR.

I'll note there has been a change in our use of the non-GAAP term Funds from Operations. It now includes the settlement of asset retirement obligations and deferred revenue. The full definition is available in the advisories to the new release and the MD&A. All figures are in Canadian dollars and before royalties unless stated otherwise.

As usual, you are invited to direct your specific modelling questions to our Investor Relations Team following the call.

Rob will now begin the call.

ROBERT PEABODY:

Thanks, Dan, and good morning everyone. In spite of a challenging oil price environment, the second quarter unfolded largely in line with our expectations. We produced about 320,000 barrels of oil equivalent, up from about 316,000 barrels of oil equivalent per day a year ago.

That includes the impact of 34,500 barrels of oil equivalent per day of asset sales over the last 12 months.

With WTI oil prices averaging US$48, about $3.50 lower than the previous quarter, we generated increased Funds from Operations of $715 million. Free cash flow was $135 million, and we more than broke even on an adjusted earnings basis. We realized these results despite scheduled turnarounds at both the Upgrader and our asphalt refinery. This is a reflection of the ongoing improvements we have been making to our asset base that are lowering our costs and increasing margins. This allows us to continue to execute our capital program as planned, which will result in further reductions in our cost structure.

Capital spending of $580 million during the quarter is keeping us on track with our revised lower capital guidance, between $2.5 billion and $2.6 billion for the year.

Our results reflect the strategy we laid out at our Investor Day at the end of May when we outlined our direction, project list and expected cost structure improvements for the coming five years. Our main message at that event was this: We are focused on reducing the price we need to breakeven on earnings.

We are doing this by investing in a deep portfolio of projects that will materially lower our cost structure, improve margins and provide free cash flow in a low-price environment. Each new investment must generate a 10% IRR on a flat US$45 WTI oil price and have at least a zero IRR at US$35 WTI.

Our balance sheet remains among the strongest in the industry with net debt at about $3.5 billion at the end of the quarter.

All of this improves our resilience to downward trends in the commodity cycle while enhancing our ability to benefit from upside commodity price swings.

We are continuing to advance our two core businesses, the Integrated Corridor and the Offshore, which provide many opportunities in which to deploy capital and earn good returns. Two-thirds of our overall capital program is directed toward short medium cycle investments in these two segments, providing increased capital flexibility. As a reminder, the Integrated

Corridor includes all of our Thermal production, the Lloyd Upgrading and Refinery Complex, the Midstream partnership and our refineries in the U.S. Midwest. It is further supported by our gas resource play production in Western Canada which provides an internal hedge for our Thermal and Refining energy needs. The tight physical integration of these assets and secure market access to the U.S. allows us to capture the full value chain margin from our production.

Total average Upstream production along the Corridor in Q2 was about 247,000 barrel of oil equivalent per day. This included about 117,000 barrels per day of thermal production and 30,000 barrels a day of resource play production. Average Upgrading and Refining throughputs were 316,000 barrels per day compared with 255,000 barrels per day in Q2 2016. Upstream operating netbacks in Corridor were $15.29 per barrel of oil equivalent. Adding to this were Canadian Upgrading margins of $22.63 per barrel and U.S. Refining margins of US$7.42 per barrel.

The Offshore business encompasses our operations in the Asia Pacific and Atlantic region. This includes production offshore China and Indonesia, and exploration offshore Taiwan, as well as our Atlantic operations with light oil production in the Jeanne d'Arc Basin and future opportunities in the Flemish Pass.

The Asia Pacific segment of our portfolio in particular really sets up apart from our North American peers. Above and beyond the stability provided by our fixed price contracts, we capture netbacks above CA$50 per barrel and we expect to generate more than $4.2 billion in free cash flow from this region over the coming five years.

We realized an important milestone in the quarter, the testing and commissioning on the liquids rich BD gas project offshore Indonesia. Gross production is now around 30 million to 40 million cubic feet per day and will continue to ramp up through 2017 towards full gas sales rates. This gas fetches about CA$9.50 per million standard cubic feet with future escalation factors, and has an operating cost of about CA$1.25 per mcf.

In the Atlantic, West White Rose was one of the biggest headlines in the quarter. The project is of similar scale to the original White Rose development. We made significant improvements to the project since it was first considered. They include boosting expected capital efficiency by 30%, increasing anticipated gross production—gross peak production to 75,000 barrels per day, and improving the overall resource capture. This project can deliver a 12% rate of return at a flat US$45 WTI oil price.

Timing is an important factor here. By proceeding now, we can make use of existing infrastructure. By tying back to the SeaRose FPSO, this results in incremental operating costs of just $3.00 a barrel for this project. Project services are widely available with the wrapping up of the Hebron project. Moving ahead with this project is immediately accretive to earnings as the project costs reduce current royalties from the White Rose field.

Looking now at the quarter, combined average production in the Offshore business was 72,700 barrels per day. Operating netbacks were $51.54 per barrel of oil equivalent, consisting of $61.90 per barrel of oil equivalent in the Asia Pacific and $42.08 per barrel in the Atlantic.

With the free cash flow being generated from Asia Pacific, the Offshore business will cover the investments at West White Rose and offshore Indonesia, and still contribute material free cash flow to the rest of the Company. Free cash flow is expected to work out at about $550 million this year from the whole of the Offshore business, and about $2.7 billion over the next five years while providing defined growth which extends well into the next decade through the West White Rose project.

I'll sum up by saying that our second quarter results indicate we are on track with our plan. We are generating free cash flow at lower commodity prices. Along the Corridor, our growing Thermal production is lowering our breakevens and continues to be supported by increased heavy oil processing capacity, providing for improved margins across the value chain, and both West White Rose and the BD project are driving further value in our high netback Offshore business.

Now I'll ask Jon to take us through our second quarter results in a little more detail.

JONATHAN MCKENZIE:
Great. Thanks, Rob, and welcome everyone. Overall average Upstream production was about 320,000 boe per day, up from 316,000 boe per day in the second quarter of 2016. June production averaged 325,000 boe per day and we remain on track with our annual guidance range of 320,000 to 335,000 boe per day. Production reflected usual seasonal maintenance as

well as further dispositions in Western Canada where we sold assets representing about 2,600 boe per day for net proceeds of $123 million. All together since the second quarter of last year, we have sold about 34,500 boe per day of production. We have more than replaced these legacy assets with lower cost, higher value production.

Total Upstream operating netbacks were $23.53, an improvement of more than 35% over the $17.30 in Q2 2016.

The average realized price for our total Upstream production was $41.58 per boe, which compares to $34.59 per barrel in the second quarter of 2016. This includes average realized pricing of $13.44 per thousand cubic feet for our Liwan gas sales.

Now in the Downstream, throughputs averaged 316,000 barrels per day compared to 255,000 barrels per day in the second quarter of 2016, which, like this year, was also a busy turnaround quarter. Asphalt margins were robust at $21.56 per barrel, with margins of $22.63 per barrel at the Upgrader.

The Chicago 3:2:1 crack spread was lower by a couple of dollars, averaging US$14.36 per barrel compared to $16.67 per barrel in the second quarter of 2016. As a result, the average realized U.S. Refining margins were about US$7.42 per barrel, which takes into account a FIFO loss of approximately US$1.37 per barrel. Now, this compared to US$16.46 per barrel in Q2 of 2016, of which about $8.94 per barrel was a FIFO gain.

Now, overall across the business, we recorded $715 million in Funds from Operations. This included a pre-tax FIFO loss of $39 million, a $20 million expense related to asset retirement obligations, and an $18 million charge related to exploration wells in the Flemish Pass.

We are continuing to drive efficiencies across our capital program and continuing to get more for less. Capital spending in the quarter was $580 million, which is on pace with our previously revised guidance for 2017 of between $2.5 billion and $2.6 billion, and we saw free cash flow of $135 million.

Net earnings were a loss of $93 million compared to a profit of $71 million last quarter and a loss of $196 million a year ago. This primarily reflects $123 million after tax impairment and a $23 million gain on asset sales in Western Canada.

Adjusted net earnings, which is a better reflection of ongoing operations, were $10 million, and this compares to a loss of $91 million in Q2 2016.

Further supporting our strategy, our liquidity remains in good shape with net debt of $3.5 billion at the end of the quarter. On an annualized basis, we're sitting at around one times net debt-to-cash flow. This number also includes $2.5 billion in cash. We also have $4.1 billion of unused credit facilities.

Our balance sheet is positioned to be sustainable through the bottom of the cycle and we are in good shape to maintain our investment grade ratings.

In regards to upcoming turnarounds, we have a three-week maintenance program scheduled in the Atlantic at both the SeaRose and Terra Nova in the third quarter.

To finish up, we are making investments in low-cost developments across our portfolio to further improve our margins and reduce our breakeven point, with an eye to returning a sustainable cash dividend to shareholders when the conditions are right. This approach is keeping the Company on a strong financial footing throughout the commodity price cycles while providing for better risk-adjusted returns.

Now I'll turn the call over to Rob Symonds to review our operational progress.

ROB SYMONDS:

Thanks, Jon. I'll start at the top of the Corridor with a look at our Thermal operations. At Lloyd, our three most recent thermal projects at Edam East, Warren and Edam West continue to produce above the design capacity. Construction is continuing on the 10,000 barrel a day Rush Lake 2 project which will start up in the first half of 2019. The next three projects at Dee Valley, Spruce Lake North, and Spruce Lake Central are scheduled to start up in 2020, adding another 30,000 barrels a day of capacity. Meanwhile, we are continuing to work on new carbon capture technologies in conjunction with our cold EOR activity. Plans are underway for a first of its kind facility at Pike's Peak South, which will capture CO2 from the steam generator. We piloted a demonstration there earlier this year and are now in the design stage for a 30-tonne per day plant but it's expected to start up next year. I'll remind you that we have produced about 3 million barrels of heavy oil using CO2 enhanced technologies and we are currently producing about 2000 barrels per day with this technology.

At Tucker, we're making steady progress towards our 30,000 barrel a day design capacity. We recently brought on a new 8-well pad and completed drilling on another 15-well pad. Gross production from the 15-well pad is expected to ramp up in the first half of 2018.

At Sunrise, gross production was 38,300 barrels per day in the quarter, up 7% over Q1. Production month-to-date in July is averaging some 41,000 barrels per day, which works out to an average of 745 barrels per day per well pair, approaching our expectation of 800 to 900 barrels a day with the original 55 wells. We're completing the tie-in of an additional 14 well pairs, and we started steaming the first pair last week, and expect the rest to begin steaming through the quarter. We'll see initial production from these pads before the end of the year.

Turning now to the Downstream, U.S. throughputs were about 245,000 barrels per day, which represents capacity utilization of about 95%. Our Downstream operations continue to support Upstream production as we further increase our heavy oil processing capacity. At Lima, the investments we are making will increase this capacity to 40,000 barrels per day by the end of 2018. At the asphalt refinery, which is an important component of our Lloyd Complex, engineering is progressing on a project that could double our current production capacity of 30,000 barrels per day. As mentioned earlier, we successfully completed two major turnarounds, at the Upgrader and the asphalt refinery, and both are now back to regular operations.

Meanwhile, our new and growing Midstream Partnership is also supporting our Thermal growth. Construction is ongoing on the LLB Direct Pipeline which will come into service in 2018. We're also building out the northern leg of the South Saskatchewan Gathering Line which is set for completion in 2020.

In terms of our resource plays in Western Canada, we made good progress over the quarter. We are continuing with some portfolio tidy-ups, which in Q2 represented about 2600 boes a day of mostly medium and heavy oil. We're currently producing about 80,000 boes a day in Western Canada, of which more than 80% is gas. And we are targeting measured growth in the selection of lower-cost, higher yielding liquid-rich gas plays. These short cycle plays offer low operating costs and better capital efficiencies than our legacy production, which they replaced, and this is increasing our netbacks.

In the Wilrich formation, we completed five wells in the second quarter with two now on production and the rest coming onstream in Q3. We're now 7 wells into this year's 16-well schedule at Ansell and Kakwa.

In the oil and liquid-rich Montney formation, we are working a four-well drilling program in the Wembley and Karr area. The first well at Karr is currently on test. We'll tie it in later this quarter. The second well is currently drilling and will be tied in during Q4. The initial Wembley well will be tied in later this month and the second Wembley well will be drilled by Q4.

Moving now to our Offshore operations, starting with Asia Pacific. Rob touched on our new production at the liquid rich BD gas project. As mentioned, this is the first of a series of capital efficient projects in the queue offshore Indonesia. Like our Liwan gas project offshore China, the BD field is located close to a local market, in this case East Java, with a growing demand for natural gas. Once the testing and commissioning has wrapped up, we're expecting to ramp up towards gross daily sales gas production of 100 million standard cubic feet per day. Husky's working interest is 40 million a day with 2400 net barrels a day of associated liquids.

Next in line are the MDA/MBH fields which are being developed in tandem. The shallow water platforms for those are now in place and the contract for a floating production unit is in progress. First gas from this combined project is expected in the 2019/2020 timeframe. An additional field at MDK will be tied in during the same period. All three fields will share infrastructure, including the FPU, and the processed gas will be tied directly into the nearby existing East Java subsea pipeline. In addition, pre-engineering activities are now underway at the MAC field. We're also evaluating two additional discoveries in the area for potential development.

Offshore China, gas sales at the Liwan gas project during the second quarter averaged 272 million standard cubic feet per day or about 133 million standard cubic feet per day net to Husky. Our average realized sales price was $13.44 per mcf, contributing to the overall Asia

Pacific netback of $61.90 per barrel of oil equivalent. June production at Liwan averaged 331 million standard cubic feet per day or about 162 million standard cubic feet per day net to Husky. Liwan is currently producing at about that rate through July.

Looking now at the Atlantic business, the West White Rose project is underway. Construction of the platform is set to start in the fourth quarter of this year, and is scheduled to be installed and connected to the SeaRose in 2021 with start-up the following year. With expected net peak production in the range of 52,500 barrels a day, this project represents a renewal of our Atlantic business. The South White Rose extension, we're planning to add a development well in the fourth quarter of this year with an anticipated net peak production rate of 4500 barrels a day.

On the exploration front, we're currently assessing a new discovery at Northwest White Rose where we delineated a light oil column measuring in excess of 100 gross metres. Any potential development here could use our existing subsea infrastructure as well as the SeaRose and the new West White Rose platform.

Thank you. Now I'll turn the call back to the Operator so that we can take your questions.

OPERATOR:
We will now begin the question-and-answer session. To join the question queue, you may press star, then one on your telephone keypad. You will hear a tone acknowledging your request. If you're using a speaker phone, please pick up your handset before pressing any keys. To withdraw your question, please press star, then two. We will pause for a moment as callers join the queue.

The first question comes from Neil Mehta with Goldman Sachs. Please go ahead.

NEIL MEHTA:
Good morning guys. Thanks for taking my questions.

ROBERT PEABODY:
Hi, Neil.

NEIL MEHTA:

So, first question is just around the current levels of production. In the second quarter, there was some turnaround activity and with some of the new production starting backup, just wanted to get a sense of where we are right now from a volume perspective. Any colour there could be helpful.

ROBERT PEABODY:

Sure. I'll get Rob to tell you. He is in touch with that day-to-day.

ROB SYMONDS:

Yes, Neil. It's Rob Symonds. Certainly, our production currently is back up towards the 330 level, and we're very much on track, as Jon highlighted, to land within the guidance range that we provided.

NEIL MEHTA:

Okay, great. Then I want to talk about the dividend at just the latest thought there. You talked about sort of the bogeys that you need to see in order to get to the point where you feel comfortable resuming the dividend. The biggest one, which is out of your control, is the views on the oil macro and getting comfort around that. So, latest thought in terms of how we should be thinking about the willingness to resume the dividend, especially as I'm sure you've had discussions with the Board since we last got an update?

JONATHAN MCKENZIE:

Hi Neil, it's Jon. We've been very consistent on this, and the answer I am going to give you is very similar to the answer I gave you in Q1, a very similar to the answer I gave you at the end of 2016. What we've said all along is we are looking at three pre-conditions to being able to resume the dividend, and we do recognize there is something that is a great value to our shareholders, and we have an equal priority in managing our capital program and returning capital back to our shareholders. But we've been very clear that the balance sheet needs to be repaired and we're very comfortable that has been done, and we are very comfortable with our current levels of debt.

Secondly, we said we needed to be free cash flow positive and earnings positive, and in today's market, we're there. We've had three good quarters of positive free cash flow, and on an operations basis at this low oil prices we continue to generate positive earnings.

The last piece that you referenced in and around stabilization of the commodity market and starting to see a trend that would support reintroduction of a dividend is somewhat more subjective than it is objective, as the other two prerequisites are. It's something that we consistently discuss with the Board on a quarter-to-quarter basis, but it would be pretty difficult to argue with the volatility that we've seen, both in terms of supply and demand through the quarter, as well as how that impacts price, that we are in a world where we think we've got stability in the commodity price, and clear direction, or even direction, as to where the commodity price might be going.

So, with that in mind, it's something we'll look at again in Q3. We do recognize the importance to the investors, but it wasn't something where we saw a clear direction for the quarter.

NEIL MEHTA:

That's helpful, Jon. Then last question from me is actually around Downstream. There has been a lot of talk about RINs here in the U.S. with the 2018 RVOs that came out. Any thoughts in terms of how potentially higher RINs prices could impact the Downstream business? I'll leave it there?

ROBERT PEABODY:

Yes, it's Rob. Clearly, we live with RINs prices and we've been living with them for quite some time now. We have some ability to blend some products in order to relieve some of the burden of RINs prices. We're still hoping that eventually they will come up with a better system. This still seems like the most complicated possible way to get ethanol into gasoline; only could be dreamt up by Washington bureaucrats, I'm sure. So, I think there is better ways, but we are kind of managing them. We certainly are of the view that there is still a misallocation here with one person responsible for the generation of RINs and then another person responsible for sort of pulling the whole together. We'd like to see the market move in a more rational way in the future. It's also a rather disturbing market, personally, that it seems to be a market that moves on the basis of somebody in Washington deciding an allocation, but there you go.

So, we're living with it and we will see where it goes. I wish I could tell you with any sort of firm direction where it's likely to be going, but I think that's kind of out of our hands at the moment.

NEIL MEHTA:

Thanks guys. Appreciate the time.

OPERATOR:

The next question comes from Jason Frew with Credit Suisse. Please go ahead.

JASON FREW:

Good morning. I think I'm just wondering about capital allocation in terms of Western Canada, specifically Karr/Wembley areas versus Wilrich. How do you see those competing over time? Are they competing? What are the constraints if you have stronger success at the Karr/Wembley area? Thanks.

ROBERT PEABODY:

Go for it.

ROB SYMONDS:

Thanks, Jason. It's Rob Symonds. As you know, we are early days in the Karr/Wembley area and have sort of confirmed success on our Wilrich plant. Currently, I would say the situation is we are allocating more to the Wilrich, partly because of the infrastructure issues; we're able to move product out of the Ansell area, whereas, as you know, there is industry constraints in the Karr/Wembley. So, we're going to determine what we have. Certainly, at type curve, the Montney is very attractive and if we're able to get egress we would start to allocate more capital, but it's more the 19/20 timeframe that it is currently.

JASON FREW:

Okay. Thank you.

OPERATOR:

The next question comes from Ashok Dutta with Platts. Please go ahead.

ASHOK DUTTA:

Hi, good morning. I had two quick questions, if I may, please. The first is, you're talking about the Offshore maintenance in the third quarter. Is there any way I could ask for a more specific timetable on that please?

ROBERT PEABODY:

I think it's in October. They're both 21-day approximate shutdowns for White Rose and for Terra Nova.

ASHOK DUTTA:

Production would not be impacted, would it?

ROBERT PEABODY:

Oh, yes. Production will be impacted for both of those fields. They'll go down to zero production for those 21 days.

ASHOK DUTTA:

Okay. Is it Rob who is answering?

ROBERT PEABODY:

Yes.

ASHOK DUTTA:

Okay. Hi Rob. The second question is a little bit on the asphalt refinery. Engineering work has been underway, but is there a timeline for taking it further, or do you see margins going down for any reason?

ROBERT PEABODY:

I guess, first of all, we continue to like the asphalt business, and one of the things we like about it is actually it has had a very long period of very stable margins. Of course, we're already a significant player in the North American asphalt business, producing about 5% of North America's asphalt, but it's a business we know very well and we like the financial characteristics of it. So, we are moving and we have been working on the engineering of that project.

We haven't taken a sanction decision at this point because we'll have to get to a point where we can get to FID before we'd be doing that anyways. But it provides—strategically, I'd just emphasize again, too, it provides a home for all our heavy oil production or for a portion of our heavy oil production, and our heavy oil production is almost—I mean it's one of the few crudes in the world that makes a very, very high-quality asphalt without additive, so we feel we have a real competitive advantage there.

So, we'll continue engineering that plant, and I think we've said before, towards the end of this year, probably early next year we'll have another look at it.

ASHOK DUTTA:
Okay, thank you.

OPERATOR:
Thank you. Our first media question is from Alex MacPherson with the Saskatoon StarPhoenix. Please go ahead.

ALEX MACPHERSON:
Good morning. Thank you for taking my question. Rob, we are just over a year out from the pipeline spill into the North Saskatchewan River last summer. In that time, can you talk about how that incident has affected, not just Husky's reputation but the reputation of the energy industry, and what's it going to take for your Company and the industry to repair public trust in Saskatchewan?

ROBERT PEABODY:
Sure. Thanks, Alex. Yes, it has been a year now. I guess a couple of things I'd say about that. First, at the very start, I want to say it's a funny thing but an incident like this does help build your relationship with the community. We worked very closely on the whole spill response with the local community and with the First Nations groups in the areas. Everybody did an outstanding job, I have to say. It was actually quite heartwarming to be up there watching the response by everybody involved.

But we certainly realize that spill had an impact on communities and the First Nations downstream, and as I say, we're certainly grateful for the support and cooperation we received.

At the height of the operation we had more than a 1000 people that were involved in that clean-up effort, including more than 450 First Nations people who, as I said, did an outstanding job.

We've learned some lessons there. As in all these things, when they don't go right, the key—and I think to your point on reputation—the key is to learn from anything like that, that happened, and we've been doing just an extensive investigation ourselves. I am sure you're aware other people are also doing investigations. We're trying to learn from everything that everybody is doing here. We expect to move forward. We've recently been given permission to go forward and repair the pipeline. We've got a little more work to do with all the authorities before we're all comfortable, ourselves including, that we want to restart it. There's a lot of changes that are going to take place there. There is going to be changes to the design, changes to monitoring equipment.

What's interesting is this wasn't a pipeline without monitoring equipment. This actually had two leak detection systems on it already, so the question is, is what can we learn? What can the industry learn in order to respond even faster to any anomalies in the pipeline operation?

So, I think the short answer to your question is like anything—I think even when I was a child, my mother used to tell me this—learn from your mistakes and don't do it again, and make sure that other people also learn from your mistakes, if possible, so everybody can not do it again.

ALEX MACPHERSON:
Just to follow-up on that, Rob, is there one lesson that this Company has learned in the last year that stands out to you as maybe the most important takeaway from what happened last summer?

ROBERT PEABODY:
Well, I'd just say that we don't want it to happen again. I do think there was a silver lining in this in that it really did allow us to build closer relationships with both the community and First Nations. I think that to me is how do you use—what you have to be reminded again, but how do you actually use a crisis to kind of build, take something positive away from it, ultimately?

ALEX MACPHERSON:
Perfect. Thank you very much.

OPERATOR:

The next question comes from Ethan Lou with Reuters. Please go ahead.

ETHAN LOU:

Hi. Good morning guys. Thanks for taking my questions. I am wondering in terms of Oil Sands operations, what WTI price you need to break even and whether you can give a breakdown of the costs per barrel?

ROBERT PEABODY:

Well, what I'll do is I'll give you a very high-level answer, and certainly if you want to call our people they can give you a lot more detail. But where we are, if I just look at something like Sunrise and where we are and where we are going to, our intention is that Sunrise operating cost per barrel will ultimately get into the $10 range. So that's—on a given day, that's your operating cost per barrel, and then you have to look at diluents and a bunch of other things that are going on.

Right today, even though Sunrise is operating at—we're still ramping up and is at roughly I think 41,000 at the moment. It's actually just about breakeven today even though it's still in ramp-up mode. So, if you look at its actual results right at the moment, it generally is just around breakeven today, but we expect that to drop down further as we get it up to full production and the unit cost rates come down, both the unit operating cost rate and the unit cost to transport the dilbit and the diluent up to the site because those are all take-or-pay contracts with fixed volume things, so when you use them all the costs go down.

I guess the other thing I'd say is, beyond that, I'm quite encouraged the things that can be done to further reduce costs in almost structural way, and we talked at our Investor Day about some technology we have that we're working on. I know others are as well, to make significant reductions in the diluent usage that we need to transport the product. Those technologies alone could actually add another $5 or so to the netback going forward. That's just one of many, many technology improvements that we and others in the industry are working on.

ETHAN LOU:

I see. Thank you, Rob. My next question, I am wondering at what stage the talks with TransCanada are with respect to shipping on Keystone XL?

ROBERT PEABODY:

I'm not—I think you'd be better off asking TransCanada that.

ETHAN LOU:

I see. Has Husky committed any volumes?

ROBERT PEABODY:

I don't think we've disclosed that one way or another.

ETHAN LOU:

Okay. Thank you.

OPERATOR:

The next question comes from Geoffrey Morgan with Financial Post. Please go ahead.

GEOFFREY MORGAN:

Hi. Thank for taking my question. Earlier on the call you had mentioned that the balance sheet in your view has been repaired. Wanted to ask you, there are a lot of assets for sale in Canada right now, a lot of companies selling. Would Husky be interested in these assets, and if so, in which formations? I'll have a follow-up as well.

ROBERT PEABODY:

I guess I'd just say that we always look at all opportunities coming along. I think you're correct that there's probably more opportunities than there has been in a while out there, but any acquisition has to compete with what we consider our very strong organic investment portfolio. We'll continue to look, but the opportunities have to clear a pretty high bar.

GEOFFREY MORGAN:

Okay. What would you prioritize? Doing an acquisition if there was something that was especially attractive or reinstating your dividend? Or is that not a fair comparison, one or the other?

ROBERT PEABODY:

It's probably not a fair comparison. It depends just how attractive, but maybe I'll pass that over to Jon.

GEOFFREY MORGAN:

Sure.

JONATHAN MCKENZIE:

To answer your question, both are important. We haven't prioritized one versus the other. We recognized the dividend is important, as well as reinvesting in our asset portfolio. But to Rob's point, anything we would do on the M&A side has to compete with the portfolio and it's got to compete with the existing capital plan, which we think is robust. It certainly takes us to a very different place on a cost structure basis. What you won't see us do is something that's off-strategy or outside sort of the existing operating areas that we're in.

We made a commitment to stay diversified and to stay integrated. Our capital plan reflects that and it gets us to a very good place in terms of our future cost structure. But we are always looking at opportunities to improve upon that plan, with an eye that we need a sustainable dividend that our shareholders value when the conditions are right.

GEOFFREY MORGAN:

Okay, thank you, and if I can sneak in one more? In terms of prioritizing investments in oil assets in Western Canada versus the Atlantic, how do the costs compare between the two? If you had a line-up of projects, where would Western Canada fit relative to some of the projects you are investing in the East?

ROBERT PEABODY:

Sorry, this is Rob again. I'd just say that we're prioritizing investing sort of out in our two core businesses, the Offshore business, the Integrated value chain. I think the priority is mostly about reinforcing those businesses going forward. That's kind of—it's not an either/or, it's how do we take each of those businesses and making them stronger over time?

JONATHAN MCKENZIE:

Yes, and I would add to that those investments have unique fingerprints but what's core to us is those investments clear our internal hurdle rates, so to compare one versus the other is a little bit apples-and-oranges in that they do have different characteristics and financial fingerprints. What is clear is that anything we invest in needs to clear our hurdle rates of 10% at $45 and zero at $35 IRRs.

GEOFFREY MORGAN:

Okay. Thank you.

OPERATOR:

The next question comes from Ian Bickis with the Canadian Press. Please go ahead.

IAN BICKIS:

Yes, thanks for taking my question. I was hoping to get an update on the total cost of cleanup of the Saskatchewan spill with another round of cleanup underway, and also kind of just the overall cost to the Company of the spill and of disruptions to operations that you've had.

ROB SYMONDS:

Yes, this is Rob Symonds. At the end of 2016, the total cost that it had been incurred by the Partnership was $107 million, and while, yes, we're on the rivers again, that number largely accounted for all of the costs as we go forward.

IAN BICKIS:

So, that includes everything that you're doing this year as well?

ROB SYMONDS:

The 107 largely accounts for all the costs.

IAN BICKIS:

Okay. Then just quickly on the East Coast, the well that Statoil and you drilled, there two that were dry, did that affect at all any future investment plans, and how much did those wells cost to drill?

ROBERT PEABODY:

I guess the main thing to say is the Flemish Pass, I think in both our companies' minds remain an excellent development opportunity. Again, we've had successes at Mizzen, at Harpoon, at Bay du Nord, at Baccalieu, so it was definitely disappointing having two dry holes, but overall, we're still pretty happy with the way the whole thing is coming together.

The wells were actually drilled, I don't—I think the total cost to us, our 35% was somewhere in the range of around $18 million, which was under the original budget that we had planned for the wells. The wells actually drilled very rapidly and we had really good productivity on them.

IAN BICKIS:

Okay, thanks.

OPERATOR:

The next question comes from Chris Varcoe with Calgary Herald. Please go ahead.

CHRIS VARCOE:

Hi, Rob. Just a follow-up on Alex's question. You talked about the fact that you've done an investigation into the pipeline spill in Saskatchewan. I'm wondering what changes are you making or have you already made as a result of that investigation?

ROB SYMONDS:

Sure. This is Rob Symonds. Certainly, once we went through a very significant investigation of all the incidents that occurred and we've transferred the learnings, particularly on slope stability, over to all of our operations and have shared those with other pieces.

For the specifics of 16TAN repair, we have put in a number of enhancements over what was there before, particularly on monitoring movement on the line, including fibre optics on the pipeline, inclinometers to measure ground to ensure we are on top of ground movement, higher grades of steel, thicker wall pipe, to ensure that we really understand what happened, we designed a case that will not occur again, but we monitor it because, of course, ground movement is an unpredictable thing. So, I think we're transferring that learning everywhere.

CHRIS VARCOE:

Just a follow-up, and this is a more general question, but you mentioned the fact that you had two pipeline leak detection systems that have failed. We've seen this similar problem with leak detection systems not working as well in other spills involving producers. Why do you think that producers are having so much problems with internal leak detection systems, or maybe more specifically, why did you have a problem with yours?

ROBERT PEABODY:

First of all, what I'd say is the leak detection systems didn't fail, but now we're getting into a very complicated answer which probably isn't appropriate here. But what I would say is pipeline systems are dynamic systems and things are happening in them all the time, so you can imagine, if you're looking at pressure and flow data, it's always fluctuating to some degree, so that any leak detection system is trying to find anomalies in a fluctuating and dynamic system. So, it's not that the systems failed, it's just that there wasn't an unambiguous message coming from the systems, at least that would be my interpretation of it. But these additional systems are to focus more locally on high risk areas so that you've got a better chance of getting an immediate indication.

OPERATOR:

This concludes time allocated for questions on today's call. I would like to turn the conference back over to Mr. Rob Peabody. Please go ahead.

ROBERT PEABODY:

Thanks very much and just to wrap up I just would say overall, we delivered quarter-over-quarter increase in Funds from Operations against the backdrop of lower WTI prices and two significant turnarounds in our operations. This is a reflection of how our cost structure continues to improve, bringing down our earnings and cash breakevens and further increasing our ability to generate free cash flow. Thanks again everyone for joining us today.

OPERATOR:

This concludes today's conference call. You may disconnect your lines. Thank you for participating and have a pleasant day.