



HUSKY ENERGY

2018 PRODUCTION GUIDANCE / CAPITAL EXPENDITURE PROGRAM CONFERENCE CALL TRANSCRIPT

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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 2018 Guidance 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.

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 today. I'm here with CEO Rob Peabody, CFO Jon McKenzie, COO Rob Symonds, and other members of our Senior Executive Team. They will outline our 2018 production guidance and spending plans, and then we'll open the line for questions.

Today's call includes forward-looking information. I'll direct you to the advisory included in this morning's news release, which describes the various risk factors and assumptions pertaining to the forward-looking information. These are also available on our website and in our annual filings on SEDAR and EDGAR.

All figures referenced during this call will be in Canadian dollars and before royalties unless stated otherwise.

Our Investor Relations Team will be on-hand after the call to answer any of your detailed modeling questions. You can also access our full guidance numbers on our website. Thanks, and now Rob will begin today's call.

ROBERT PEABODY:

Thanks, Dan, and good morning.

Setting out our direction for 2018, we are improving on our targets we laid out at our Investor Day in the past May.

We made good progress in 2017, having met or exceeded many targets, including lower capex and lower operating costs.

The investments we've been making in our Integrated Corridor and Offshore businesses are providing for stronger returns, higher margins and further reductions to our cost structure and our break-evens.

As such, we are increasing our funds from operations and free cash flow beyond the original plan, and the outlook continues to improve over the next four years.

The acquisition of the Superior Refinery alone will increase free cash flow by about \$500 million over the plan, as well as immediately further reducing our exposure to the light/heavy differential.

At the same time, we have accelerated the expected timeframe to bring several projects onto production.

As we mentioned in October, we are moving up first oil at Rush Lake 2 to the first quarter of 2019, as well as advancing two Atlantic infill wells at White Rose and North Amethyst.

We also took the opportunity to sell some additional legacy assets in Western Canada, which further focuses our portfolio and improves our cost efficiency.

Altogether, we expect to sell about 20,000 barrels of oil equivalent per day in 2017, bringing our overall dispositions to approximately 52,000 barrels of oil equivalent per day since we started on this program.

Our anticipated production remains in step with our production target of 400,000 barrels per day by 2021, representing a compound average annual growth rate of about 7% over the coming four years.

Contributing to this is the recent Board sanction of three new projects that will come online in 2021.

Two more thermals at Edam Central and Westhazel will add a combined 20,000 barrels per day of capacity when they come on in the second half of 2021, and we will be starting construction next year on the third field at Liwan.

Looking now at next year, average annual production is expected to be in the range of 320,000 to 325,000 barrel of oil equivalent per day.

This is on par with our 2017 production, even taking into account the sale of about 20,000 barrels of oil equivalent of legacy assets in Western Canada this past year, which I spoke of earlier. Adjusting for these dispositions, the midpoint of our guidance represents a 6% year-on-year production increase.

In our Corridor business, thermal production is expected to grow at about 12% year-over-year, and Offshore, we are looking for a 16% increase in Asia Pacific production as the BD project continues to ramp up in Indonesia.

We are experiencing continued strong demand in China for our Liwan gas. Jon will provide some additional information about how growing high-netback production in the region is increasing our overall realized gas price relative to those who only have North American gas production.

In regards to capital spending, capex will be about 10% less than we forecast as an annual average, which was about \$3.3 billion when we did our Investor Day. This is primarily due to the cost efficiencies we've been realizing, as well as the Superior Refinery acquisition.

In the Integrated Corridor, spending will be largely focused on short and medium-cycle projects. This includes growing the Lloyd thermal portfolio, where production on average is achieved within 24 months of the associated capital spend.

We are also progressing the Ansell resource play.

In the Downstream, we will continue to advance the crude oil flexibility project at Lima and complete a program to increase heavy feedstock capacity at our newly acquired refinery in Superior.

In the Offshore, we will focus on construction at the West White Rose project in the Atlantic and the 29-1 field offshore China.

Now, I'll ask Jon to review the 2018 guidance in more detail, and then Rob Symonds will provide an update on our operations.

JONATHAN MCKENZIE:

Thanks Rob, and good morning everyone. As this year comes to a close, we are tracking better than planned on both capex and operating expenses.

Full-year production for 2017 will average about 324,000 boe per day. This is inclusive of asset sales that amount to about 2,500 boe/day on an annualized basis. The last of these sales are expected to close by the end of this year.

Capex guidance, which we lowered twice this year, while still expanding the original scope of the planned work, is expected to remain within our most recent guidance at about \$2.2 to \$2.3 billion. When you add in the Superior Refinery acquisition that closed in Q4, total capital spending for 2017 is closer to \$2.8 billion Cdn.

Looking at 2018 . . . at the \$55 US WTI oil price and with \$2.50 AECO and US\$15 per barrel Chicago 3:2:1 crack spread, we expect our funds from operations to exceed \$4 billion next year.

This will not only cover our capital program but also gives us about \$1 billion in additional free cash flow. We'll refresh our guidance of the five-year CAGR and funds from operations of 9% per year that we set out in our last Investor Day when we meet again in May 2018.

The capital program will be \$2.9 billion to \$3.1 billion, which includes about \$1.1 billion of growth capital. Approximately \$2.1 billion will be spent in the Integrated Corridor and \$900 million in the Offshore.

I'll remind you, the growth capital is being directed only at those projects that clear our hurdle rate of a minimum 10% rate of return at \$45 US WTI oil price and breakeven at \$35 US.

Putting funds from operations together with expected capital expenditures, free cash flow yield for 2018, inclusive of our growth capital, looks to be around 7% and grows over the five-year plan.

Meanwhile, the steps we've taken to transform our portfolio continue to increase the value of each barrel we produce or run through our own Mid- and Downstream assets.

For example, our gas realizations in 2013, prior to the start-up of Liwan in early 2014, averaged \$3.19 per thousand cubic feet. Year-to-date 2017, they've averaged \$5.39 per mcf. This compares to an AECO average price of about \$2.15 per mcf. This reflects our increasing Asia Pacific production as well as the disposition of legacy assets in Western Canada.

Now, we also expect to continue the trend of reducing our overall Upstream operating costs, which are pegged to be in the range of about \$13 to \$13.50 per barrel in 2018. This compares to just over \$14 per barrel this year, and we remain on track with our guidance to drop below \$12 by 2021.

Our earnings break-even oil price is expected to be \$42 WTI US per barrel in 2018, compared to \$43 WTI US per barrel in 2017. Our cash break-even, which is oil price needed to fund our sustaining capital requirements, is expected to be just under \$32 US WTI per barrel in 2018, and this compares with about \$33 US WTI per barrel in 2017.

At Investor Day, we earmarked an annual average of \$1.9 billion for sustaining capital over the five-year plan. Our 2018 estimate of \$1.8 billion to \$1.9 billion stays within those parameters.

We continue to maintain our leverage comfortably below two times net debt to funds from operations, ahead of the target in our five-year plan, even with the acquisition of the Superior Refinery. Net debt at the end of the year is expected to be around \$3.3 billion, or right around one times 2017 funds from operations.

In terms of liquidity, we have \$2.2 billion of cash and more than \$4 billion of unused credit facilities.

In terms of planned maintenance turnarounds, I'll mention that these are covered in today's news release.

Now, I'll pass the call over to Rob Symonds to outline our operational objectives for 2018 and provide a brief update on our progress since the third quarter.

ROB SYMONDS:

Thanks, Jon. I'll start out at the top of the Integrated Corridor business where our thermal program continues to grow.

Rob mentioned the sanction of our two latest Lloyd thermal projects. Edam Central and Westhazel, which are both in Saskatchewan will add a combined 20,000 barrels per day of capacity when they start up in the second half of 2021.

We're currently building another four Lloyd thermals at Rush Lake 2, Dee Valley, Spruce Lake North and Spruce Lake Central. These will be adding a combined 40,000 barrels per day of capacity when they come online starting in 2019 and continuing into 2020.

In aggregate, we'll see our Lloyd thermal production grow by some 60,000 barrels a day by 2021, an increase of about 75% from today.

Our 2018 activity will be focused on building out these projects for the same kind of lower cost, modular, cut and paste approach that has proven so successful in the past. This growth is supported by our Midstream partnership, which is funding the pipeline takeaway capacity for our next eight thermal projects.

Tucker and Sunrise are also continuing to ramp up. At Tucker, steaming has commenced on the new 15-well pad, and we're expecting to hit 30,000 barrels per day next year. Current production is running between 24,000 and 25,000 barrels per day.

At Sunrise, all 14 of the new well pads are now online. Our monthly production in November averaged 46,500 barrels a day with the original 55 well pairs producing within their target range of 800 to 900 barrels per day per well.

All together, we expect our total thermal production in 2018 to grow approximately 12% year-over-year.

At the end of next year, our total production from thermal operations will be about 140,000 barrels per day, or 40% of our production base. Combined thermal operating costs will be about \$10.50 per barrel. Higher return, longer life thermal growth continues to replace our higher cost legacy production, leading to improvements in funds from operations and free cash flow.

Meanwhile, our resource play business is also making good progress. The asset disposition program is now substantially complete. Altogether, about 52,000 boe per day of legacy assets in Western Canada have been sold.

We will emerge from this program with a leaner, more focused portfolio with significantly lower asset retirement and sustaining capital requirement.

In regards to 2018 resource play activity, we plan to drill 17 net liquid-rich gas wells in the Wilrich Formation at Ansell and Kakwa, where this year's 16 well program is just wrapping up. In the Montney, we have eight wells scheduled for 2018. This is twice as many as this year, when we drilled two liquid-rich gas wells at Wembley and two oil wells at Karr.

In the Downstream, throughputs are forecast to increase about 7% in 2018 to some 365,000 barrels a day, including about 40,000 barrels a day at the Superior Refinery.

This takes into account three maintenance turnarounds at the Upgrader, the Lime Refinery and Superior. At Lima, the crude oil flexibility project will continue to be advanced. We've already increased our heavy capacity at Lima to 10,000 barrels per day. This next stage will bring capacity up to 40,000 barrels per day.

In the Offshore business, our primary objectives include further advancing our fixed price gas business offshore China and Indonesia and continuing to roll out a series of infill wells in the Atlantic. Jon has already addressed how this has increased the price we receive for our gas compared to other North American companies.

We will also start building out Liuhua 29-1. Full field development will include seven wells, four of which have already been drilled. We plan to tie 29-1 into the existing Liwan infrastructure. Gross production will be approximately 55 million standard cubic feet per day of gas and 2,400 barrels a day of liquids, when it comes on production in 2021.

As we said in the third quarter, we expect to recover approximately \$250 million US in exploration costs over and above our working interest within the first 18 months of production from this new field. This means our production share in the 2021-2022 period will be in the range of 70%.

At the BD Project in the Madura Strait, we're ramping up towards full gas sales rates of 40 million standing cubic feet per day net to Husky, with 2,400 barrels a day in associated liquids. We remain on track to hit this target in 2018. Current net gas sales are approximately 16 million standing cubic feet per day with 3,500 net barrels per day of liquids. Pricing is about \$46 US per boe, including royalties.

Overall, Asia Pacific production for 2018 is expected to come in above 47,000 boes a day, with operating netbacks of around \$63 per boe.

In the Atlantic, West White Rose is gearing up, with lots of activity as construction is set to begin. Since we sanctioned this project last June, our team has been mobilizing to the three main construction sites in Newfoundland and Texas.

At Argentina, the first concrete for the wellhead platform will be poured in the second quarter and the structure will start to take shape by the end of the year. Work on the living quarters is also proceeding at the Marystown site and will ramp up into 2019. In Texas, the team is preparing to build the topsides, which chiefly consists of a drilling unit.

It's early days, but first production is on track for 2022.

Finally, we're planning two Atlantic infill wells next year. The first well at North Amethyst will be brought on production in the first quarter. The second well at the main White Rose field will come online in the third quarter. Net peak production for each well is expected to be about 4,400 barrels per day.

This ongoing infill program, which equates to roughly two wells per year, will help mitigate declines until the West White Rose Project starts up.

Thanks very much, and now I'll ask the Operator to begin the question-and-answer session.

OPERATOR:

Certainly. We will now begin the analyst question-and-answer session. Any analyst who wishes to ask a question may press star, and one on their touch-tone phone. You will hear a tone to indicate you're in the queue. For participants using a speakerphone, it may be necessary to pick up your handset before pressing any keys. If you wish to remove yourself from the question queue, you may press star, and two. One moment, please, while we poll for questions.

Our first question comes from Greg Parady of RBC Capital Markets.

GREG PARDY:

Thanks. Good morning. I have three quick ones but probably the most obvious is in terms of the dividend. Is it fair to say, Rob and Jon, that all conditions for the resumption of the dividend are now in place?

ROBERT PEABODY:

Good morning, Greg. Yes. I think that's fair to say. I mean clearly it's a Board decision. We've been clear all along sort of that we were looking for three conditions to be met. We clearly are in great shape now (in terms of the balance sheet). Free cash flow, we're also generating lots of free cash flow. And then, the environment has kind of stabilized. Barring what I would call unforeseen events at this point in time, I think the Board is likely to be favourably disposed to that when they actually sit down and discuss it again with the 4Q results.

GREG PARDY:

Okay, perfect. Then maybe just over to Jon. As we tune up our numbers, could you give us an idea of what your cash tax picture looks like at your spending and pricing assumptions?

JONATHAN MCKENZIE:

Yes. Good morning, Greg. I'll give you some guidance for 2018. I think the last time we talked I mentioned to you that there's three jurisdictions in which we operate: Canada, the U.S. and Asia Pacific. In 2018, we only anticipate being cash taxable in our Asia Pacific business. If you're looking for guidance in terms of cash taxes for 2018 at a corporate level, a number between \$50 million and \$100 million is probably the right number for you to put into your models.

GREG PARDY:

Okay, perfect. Then maybe the last question is, for Rob is, if we take a look at your Western Canada business ex- thermal, heavy and so on, where do you see the growth coming from there on the oil and NGL side? Those numbers stood out to us a little bit as probably a little bit more of a ramp than we had expected.

ROBERT PEABODY:

I'll turn that over to Rob Symonds. He's very close to that.

ROB SYMONDS:

Thanks, Rob. Yes. Greg, now that we've got the legacy assets that we wanted to dispose of out of the portfolio pretty much done, capital is now going into the—new capital into the Montney and into the Wilrich at Ansell. The other increase in production in '18 versus '17 will be a full year of the Rainbow NGL blowdown project that'll also be ongoing.

But, that really holds Rainbow flat on a month-to-month basis. Going forward you'll see growth in both the drier gas associated liquids at Wilrich and you will see some Montney, although as you said (there are) a lot of restrictions in terms of takeaway capacity in that Central Alberta area that will reduce the amount of production you'll see in '18.

GREG PARDY:

Okay, great. What's the order of magnitude on Rainbow and when do you expect that blowdown to complete?

ROB SYMONDS:

Rainbow has got 10-year plus. The amount of liquids will decline over time. The total amount of production there right now is somewhere north of 20,000 boes a day including gas and liquids.

ROBERT PEABODY:

It's fairly flat for quite a long time though, as Rob said, sort of the next decade or so.

GREG PARDY:

Okay, great. Thanks so much, guys.

OPERATOR:

Our next question comes from Emily Cheng from Goldman Sachs.

NEIL MEHTA:

Good morning. Hey guys, it's Neil Mehta here.

ROBERT PEABODY:

Good morning.

NEIL MEHTA:

Hey Rob, how are you? First question is just a follow up to Greg's on the dividend here. As you think about sizing it and magnitude, recognizing it is the purview of the Board, could you just talk about how you think about what are the parameters by which you'll size the dividend? One of the things you've said in the past, Rob, is that it's important that the dividend comes from earnings and you're clearly covering your earnings break-even at this point, but anything more that you can expand there would be great.

ROBERT PEABODY:

Yes. When the Board discussed this in the past, there was a lot of discussion around maybe that it should be related to earnings in some fashion. An old-fashioned school way of thinking about this would be sort of something like 50% of earnings or things like that; you shouldn't go above it as a kind of condition.

It shouldn't be coming out of debt, so that's another condition when you think about it. Then, we're looking for something I think, given that the environment is stabilized, but I don't think anybody would call it stable.

I think there will be a lot of concern to make sure that when they re-establish something, they re-establish something that's going to be very sustainable and would weather well even if we do have a period of lower prices in front of us . . . or something in the near or medium term, because they don't really want to be revisiting it again because of the environmental conditions.

I hope that gives you some sense. That's kind of the discussion that goes on.

NEIL MEHTA:

That's helpful. That's helpful. Rob, there's been a lot of focus on corporate returns across the energy complex, and it's not only at the asset level but at the corporate level. Just curious on your thoughts of this. In terms of the plan that you've laid out, you're at that \$55 price. Do you see corporate returns? Do you see a credible path for corporate returns to exceed the cost of capital over time?

ROBERT PEABODY:

Absolutely, it's something that is a real focus for us as we look forward over the plan. As I look over our plan, over the five years, by the end of it we are exceeding the cost of capital. We're closing in on it over the next year or two, and it is certainly something that I have in my mind.

I know our industry. I often read the reports from a lot of companies out there and I'm always looking for the earnings number, and it's often quite hard to find, but it's something that always gets discussed internally fairly significantly. It's something the Board looks at here.

NEIL MEHTA:

Okay. The last question is WCS. With the Superior Refining acquisition and given the integrated nature of your portfolio, are you going to be a little more protected from this WCS . . . but there's still some sensitivity? Can you give us an update in terms of, one, what your views are in terms of how WCS is going to evolve over time, and two, how sensitive the business model is to that?

ROBERT PEABODY:

I guess what I'd say there is that clearly we're very pleased to get the Superior Refinery into our portfolio.

Number one, because we could then substitute that for the original plan over the next five years, which was to build the HLR 2 or the second asphalt refinery in the Lloydminster area—still something that could be done in the future but not right now—and give us the immediate impact of integration sort of over the next five years, when I guess my sense is it's going to be pretty choppy.

I mean, similar to what we've just seen recently, the system is either over-constrained or it's so close to being there, that anything that happens and you can get a blowout of the differentials. This certainly helps us in that regard.

I mean clearly, one of the benefits we have with Superior is it's hooked directly, effectively, to the Hardisty facilities where we're a big player, and with it came a lot of additional storage. Since it makes us a legitimate sort of user of crude oil down in the United States, with a bunch of storage, it allows us to nominate at higher levels, credibly nominated higher levels, and get higher nominations kind of actually given to us. So it actually does increase our access to the Mainline by having that refinery there.

NEIL MEHTA:

Great. Do you have a corporate level, Rob, of every dollar change to WCS, what it does to cash flow, or that's not something that you'd disclose at this point?

JONATHAN MCKENZIE:

Hi Neil, it's John. For 2018, we're really balanced between our production and our takeaway capacity and processing capacity. When you think about our exposure to WCS, whether it be with our Lloyd Cold Lake or even our Fort McMurray production, all of that has a home in a processing unit, whether that be in the U.S. or with our Lloyd complex. As a sensitivity in 2018 to WCS, it's really a moot point for us.

NEIL MEHTA:

That's great. All right. Thanks, Jon. Thanks, Rob.

ROBERT PEABODY:

Thanks.

OPERATOR:

Our next question comes from Phil Gresh of JP Morgan.

PHIL GRESH:

Hi. Good morning.

ROBERT PEABODY:

Hi Phil.

PHIL GRESH:

My first question is just on the long-term production guidance and some of the moving pieces behind it. You had 400,000 boe per day, fairly similar to the analysts, actually kind of at the high end of that, but when I looked at the Asia Pac slide, Slide 21 in the presentation, relative to the Analyst Day, that looked a bit lower, if I'm looking at that correctly. Maybe you could just clarify that. Then obviously you had some asset sales on the natural gas side, so I'm just wondering what the backfill is to get to the same production target.

ROBERT PEABODY:

Thanks, Phil. I mean, there was a little—I think there was a tiny bit of slippage on the Asia Pac stuff with just moving out. We actually built—in this forecast we built a one-year slippage in the Indonesian fields at the far end and that was just because of the regulatory approval side of it, not unusual.

We have accelerated, but in return we've accelerated our heavy oil thermal production compared to what was originally in the plan last year. So this is effectively now providing for two 10,000 barrel a day projects every year as we kind of go forward through that, which was the significant offset.

Then the other place where there was a little bit of offset was in Western Canada in the last couple of years of the plan, where we saw a little increase in ramp up from the Ansell and the Montney compared to the original program.

I'd characterize it as is some puts and takes in the program, but still very much on target with the original guidance we set out in terms of the long-term production growth.

Did you want to add something to that, Rob?

ROB SYMONDS:

Yes. I just wanted, Phil, to highlight for you, that Slide 21 you're looking at, that is the gas production in mcf from Asia. That's not the corporate number. That's only Asia, Asian gas, so the 400 that Rob just highlighted, you need to look at the increased thermals and the other pieces as well.

PHIL GRESH:

Okay. Yes, I was also looking at Slide 15 where the thermal for 2021 looked unchanged, but I can take it offline.

ROBERT PEABODY:

Yes, you can—yes, no problem, but there are just some puts and takes around the portfolio but it's still very solid I think.

PHIL GRESH:

Okay. Then I guess that maybe partially answers the capex question. I guess you'll talk about this in May, but the fact that 2017 lower, 2018 lower, long-term range try and maintain at the same level. I guess it sounds like maybe there's some acceleration in these growth projects that's bridging that. Is that the right way to think about that?

JONATHAN MCKENZIE:

Phil, are you saying lower in '18 and lower in '20?

PHIL GRESH:

Lower in '17. Lower in '18, but the long-term range of 3.3 annual average '18 through '21 was not changed.

JONATHAN MCKENZIE:

Yes, so what we're reflecting in the short term, Phil, what you're seeing in the first three years are some of the efficiencies that we've seen in 2017 manifesting themselves in 2018 through '20.

The scope of the projects or the scope of the capital spend hasn't changed; what has changed is the cost of the overall program. The sequencing, there have been some puts and takes in terms of accelerating some projects, and we've talked about Rush Lake 2 coming forward as an example of that, but the overall decrease in the spend that you're seeing is really related to the efficiencies that we're starting to realize in 2017 and coming through at least the first three years of our plan.

PHIL GRESH:

Okay, thanks.

ROBERT PEABODY:

Yes, I should just clarify one other thing just in case, and it's in the news release. What we're expecting is that that \$2.9 to \$3.1 sort of capital spending over the five-year period versus the \$3.3, we'd expect to see a reduction of somewhere in that range of \$100 million to \$200 million a year on average over the five years as well as that efficiency continues to flow through.

PHIL GRESH:

Oh, okay. That helps.

ROBERT PEABODY:

Yes, okay.

PHIL GRESH:

Got it. Then, Rob, just in terms of the free cash flow guidance for 2018, I know there was some discussion at some point about including the capitalized interest in the free cash flow. Is that in that number?

ROB SYMONDS:

That's in that number and it's about \$100 million for 2018.

PHIL GRESH:

Yes, okay.

ROBERT PEABODY:

Yes, we had a discussion about that. I didn't want to create another non-GAAP metric and so we decided to do it the way the accountants like. I know many of our peers have created a non-GAAP metric around that but I have that problem when we start getting into too many non-GAAP cash flow metrics.

PHIL GRESH:

Yes. Helpful, thank you.

OPERATOR:

Our next question comes from Mike Dunn of GMP First Energy.

MIKE DUNN:

Thanks. Good morning everyone. Two quick ones from me. First, just wondering what the Brent to WTI spread assumption is in your estimate of the over \$4 billion of cash flow in 2018? Then, secondly, just wondering if either or both of your capex and cash flow estimates or funds from operations estimate includes or exclude equity method accounting assets? Thank you.

ROBERT PEABODY:

I'll leave the second one to Jon. Just the first question, I'd say is that we're relatively insulated from the WTI/Brent differential, and the reason for that is because what we see is that as you assume a kind of wider Brent/WTI differential, then we actually make it up in—that tends to flow into the Chicago 3:2:1 refining crack on average over the year. That's the situation.

We actually ran a number of plans on this—and this is one of the reasons I kind of know this, is we varied the WTI differential between about two bucks and about six bucks. As you know, recently it's been as much as \$6 a barrel, but the long-term average is—well, long term, since it's been the direction it's been, has been closer to maybe \$2 or \$3 a barrel. We've kind of looked at it over that range, but we're actually relatively insensitive to it because we do tend to pick it up in the U.S. Downstream in particular as it widens.

MIKE DUNN:

Sorry. Rob, I'm just trying to calibrate our models here, so if WTI is \$55 and Brent is at a \$5 premium, you'll cash flow more than if it was a \$2 premium, so I'm just trying to figure it out . . .

ROBERT PEABODY:

What you have to do is understand how that flows through to the crack spread in the United States. I mean, keep in mind we have a lot of refining capacity in the United States, so as that spread opens up, we actually get a higher crack spread that flows through in the United States.

What we can do is take that offline and Dan can kind of take you through it in kind of detail through the calculations to get your model just right.

MIKE DUNN:

Okay.

JONATHAN MCKENZIE:

Mike, it's Jon. I think your other question was just in regards to the equity accounting for our two significant joint ventures, one being the pipeline group and the other being Indonesia.

MIKE DUNN:

Yes.

JONATHAN MCKENZIE:

What you'll see on a quarterly basis is an equity pick-up on the P&L associated with both of those, but what you won't see is the cash flow coming through until those joint ventures declare a cash distribution to the unitholders.

For the pipeline group, that happens on an annual basis, and for the Indonesian assets we're just working through that right now to determine when we'll declare those distributions back to the unitholders.

MIKE DUNN:

Okay, so a bit of leeway there in the cash—in the funds flow guidance then for this year. Then on the capex side, I guess the question is whether or not spending on Indonesia is in that \$130 million to \$150 million capex number for Asia Pacific.

JONATHAN MCKENZIE:

It is in that capex number.

MIKE DUNN:

Okay. Thank you. That's all from me.

ROBERT PEABODY:

Thanks, Mike.

OPERATOR:

Our next question comes from Paul Cheng of Barclays.

PAUL CHENG:

Hey guys, good morning.

ROBERT PEABODY:

Hi Paul, how are you?

PAUL CHENG:

Very good. Three questions, if I may, hopefully short.

First on the ticket weight capacity crossing into U.S. from you guys. If you look at your firm commitment that you have in take-or-pay contracts only, and looking at your gross production, over the next several years, will you get to a point where you need to use the rail to clear the market, or that you have sufficient for the planning period. That's the first one, then I guess I will wait until ...

ROBERT PEABODY:

Just quickly Paul, just so I don't have to remember three at once. I appreciate that. The short answer to that is we're not anticipating having to use rail over the next, you know, over this plan period at the moment with our commitments on—particularly our commitments on Keystone plus our ability to nominate on the Mainline, particularly with the Superior Refinery as well.

PAUL CHENG:

Perfect. Secondly then, for your capex from 2018 through 2021, if oil prices end up to be higher than what's in your base plan, will you increase the capex level or then you will increase the cash return to investors, or you will just pay down debt?

ROBERT PEABODY:

I always worry about speculating too far into the future, but I mean the good news is things are in good shape. We've got a good strong balance sheet to help us weather any storms along the way here.

I think we're very happy with the organic capital program we have in place. As we've said before, we're able to ensure that each investment still earns a 10% return at \$45 WTI and is at least getting to zero IRR at \$35, so we're going to keep those criteria in place, which puts us in a good position on the organic front.

If we saw higher prices and we saw even more debt getting down to very, very low levels, I think then we will continue to look, as we do today, at M&A opportunities to come along, but they need to be on strategy, very closely coupled with the game plan we already have in front of us.

Traditionally, we've found more of those when they're more bite-size than when they're big; often when you go for something big you get stuff that is not necessarily on strategy.

We'll keep a close eye on that too, but I think, again, a key focus as we go forward now, given the environment and given the journey we've been through to get our break-evens down to where they are and to get our free cash flow up to where it is, there'll be a lot of focus on the shareholder and returning cash to the shareholder as we go forward as well, and we'll balance those things.

PAUL CHENG:

A final one. Is the budget for 2018 to '21 including the amount for the Flemish Pass discovery development?

ROBERT PEABODY:

Yes. All the money that we're doing for the Flemish Pass is included in that budget. Now, there is not huge amounts of capital in the program over the next few years for the Flemish Pass. I think the last thinking on the part of the partner is that we'd probably be looking at potential sanctioning of that project sometime in around 2019 or something like that, very provisionally at this stage because it's early days, but I think that's the program they're working towards.

PAUL CHENG:

Jon, can you tell us what is the actual dollar or budget that you have for Flemish Pass in the next several years' budget?

JONATHAN MCKENZIE:

I don't have those numbers off the top of my head, Paul. We'll get them back to you.

PAUL CHENG:

Okay.

JONATHAN MCKENZIE:

They're not material to the capital budget that we've laid out over the next five years.

ROBERT PEABODY:

That's right.

PAUL CHENG:

Sure. Just trying to understand that. That would give us some idea that how big is the project and when that you guys are actually going to sanction.

ROBERT PEABODY:

Yeah.

PAUL CHENG:

Thank you.

ROBERT PEABODY:

Thanks, Paul.

OPERATOR:

This concludes the analyst question-and-answer portion of today's call. We will now take questions from members of the media. As a reminder, please press star, then one on your telephone keypad to ask a question. If you wish to remove yourself from the question queue, you may press star, and two.

Our first media question is from Reid Southwick from Calgary Herald.

REID SOUTHWICK:

Hi. Good morning. Thank you very much for taking my question. I'm wondering if you are concerned about the impact of methane emission regulations coming down from the province, as well as the output based allocation regime that's coming as part of Alberta's climate change plan. Do you have any concerns about the impact on the industry in general, and Husky in particular?

Just secondly, I'm just wondering if you have any estimates on the cost impact for the company?

ROBERT PEABODY:

What I would say is while addressing new regulations will require corrective actions, equipment repairs, gas combustion and gas conservation—this is specifically in respect to methane—we're identifying cost effective ways to comply on that and certainly we've included some funds in the budget over the next few years.

That, by the way, is an ongoing program; it's not just because of new regulations. Over the last decade or something, we've made pretty massive improvements in the amount of methane that is being released in the Company. It's kind of I'd emphasize it's an ongoing program as we go forward.

We're working very closely with both the provincial and federal governments to find the best way to reduce methane while remaining competitive, because clearly we're still sitting right up against this giant, massive competitor to the south who isn't necessarily going down the same road as Canada is at the moment.

I think what we've detected in the government is some level of concern about the competitiveness of the Canadian sector relative to the U.S. sector, so we're trying to find proactive ways forward on that.

In terms of the carbon policy, we've always said it should be market-based and sensitive to the trade, those same trade and competitive issues. Again, I think we are hearing some listening at least for that point of view in various governments we're dealing with, and we're trying to again come up with programs that will allow the implementation of a carbon tax while not hobbling sort of the Canadian industry relative to the U.S. industry. That's going well.

I think the only thing that I would add to all this, and I feel quite strongly in this, is that there's no question in my mind that Canada's oil and gas production is really superior in many, many ways to the vast majority of oil that's produced when it comes to human rights issues, women's rights issues, and to the protection of the most vulnerable sectors of our society.

It's actually, overall, it's superior to most also from an environmental standpoint, given the incredibly great and I would say rigorous level of regulation we have in this country around our production. We start from a great place on all of those issues, but our goal is also, ultimately, to be the best from a CO2 point of view and that's what we're all working on now.

REID SOUTHWICK:

Do you have any specific concerns about the cost that these programs, that these proposals could have on Husky in the long run?

ROBERT PEABODY:

Well, absolutely we have a concern and that's why we're working with the governments to try to get that in a reasonable place. Certainly with everything that's on the table at the moment, we've done our own cost estimates about what this could be.

I think we are looking at how that will impact us, but you do have to look at the cumulative impact of all taxes when assessing competitiveness, and this is just—frankly, at one level, this is just one more tax and you just have to put them all together.

It's interesting to see the U.S. may be passing a corporate tax reduction to 20%. If that goes through, that's going to be another factor in sort of understanding how the Canadian sector sits from a competitive standpoint with, as I say, our gorilla to the south.

REID SOUTHWICK:

Can you share your cost estimate?

ROBERT PEABODY:

What I would say at the moment, we haven't disclosed that and clearly the biggest issue at the moment is there is still a huge amount of uncertainty into the specifics of the regulations, even that will be in effect next year.

We still don't actually have regulations even for next year and we're into December now, which is something to be said about planning, I guess. Based on the hints we get and the little bit of information that's out there, we have built some things into our budget.

At the current stage, the numbers are not so materialist to throw off any of the other estimates that we've given you today as part of the guidance call.

OPERATOR:

Our next question comes from Geoff Morgan from the Financial Post.

GEOFF MORGAN:

Hi. Good morning. Thanks for taking my question. Wanted to ask how much of your gas is marketed at AECO and how you've been concerned or whether you've been concerned by the massive swings in the AECO spot price over the last few months, and how you're managing it.

ROB SYMONDS:

Yes, Jeff. This is Rob Symonds. We buy a lot of gas for consumption at AECO. Certainly the blowout downwards we've seen in AECO is a concern at the production end of it.

We do also have the ability to move some of our gas away from AECO. Specifically, we have pipeline capacity into California, but the real message that Husky would want people to understand is because we are essentially a zero-net buyer/seller of gas, i.e. we consume pretty much what we consume, the absolute level of AECO pricing is not a concern on cash.

Having said that, certainly we want to make sure that the capital we invest in drilling gas wells does make a return so we watch it very closely.

GEOFF MORGAN:

Okay. Would you be interested then in, for example, marketing more of your gas at Dawn if TransCanada does another long-term fixed price, or are you actively looking at other markets?

ROB SYMONDS:

We actively look at all of the markets that are available; Dawn is certainly one of them. There are other locations. Certainly though, Husky overall, because of the fact that we produce a lot of gas in Asia, means on an overall basis our gas position is quite different than a lot of our North American competitors.

GEOFF MORGAN:

Okay. Second question. Earlier on the call there was some mention of how the Superior Refinery increases access to the Mainline. Can you give me some details on how that happens? How much incremental capacity did Husky get on the Mainline as a result of that purchase?

ROB SYMONDS:

Let me start with that. The Enbridge Mainline is a nominated item; there's no firm capacity associated with it. The Superior Complex is the first major stop on the Mainline. What Rob Peabody was mentioning is that we, as part of our purchase, got access to a number of additional tanks there so that we can take off a significant amount.

The way that it works on the Enbridge Mainline is you nominate, and I think what Rob was highlighting, there are on occasion apportionment occurs but because we have a lot of tankage down there we would not be at risk of significant apportionment.

GEOFF MORGAN:

Okay. All right, thank you.

ROBERT PEABODY:

Thanks.

OPERATOR:

Our next question comes from Jeff Lewis of The Globe and Mail.

JEFF LEWIS:

Hi. Just a quick one about the Ram River sale and legacy assets. Were those separate transactions? Then secondly, what's the ARO number or is there one associated with the 18,000 boe a day?

ROB SYMONDS:

This is Rob Symonds. The Ram asset dispositions are currently expected to close towards the end of the year. As far as the specific ARO, I don't believe that we've put that out but certainly if you want to contact our Media Relations people, they'll be able to get you a number of that.

JEFF LEWIS:

Okay. I understand that the deals haven't closed yet, but is it one transaction, the Ram River and legacy assets, or are we talking about two separate deals?

ROB SYMONDS:

The specific Ram River, there are two deals ongoing, but we've also had other transactions earlier in the year that bring us in total. The Ram one you're talking about is two separate transactions with two different parties, although they are related.

JEFF LEWIS:

Okay. Thank you. I'll follow up with the Media Relations about the ARO number.

ROBERT PEABODY:

Super.

ROB SYMONDS:

Thank you.

OPERATOR:

Our next question is from Pat Roche of the Daily Oil Bulletin.

PAT ROCHE:

Hi. I assume Ram River is a sour gas plant. Is that correct?

ROB SYMONDS:

Correct.

ROBERT PEABODY:

Yes.

PAT ROCHE:

What's its total capacity?

ROBERT PEABODY:

Do you know the capacity today? It started out as a much bigger plant and then parts of it were shut in several years ago.

ROB SYMONDS:

At the current capacity, it isn't processing anything close to this; the current capacity is probably in the order of 400 million standing cubic feet a day.

PAT ROCHE:

Okay. What's its utilization rate right now?

ROB SYMONDS:

The utilization rate was very low. As I say, we are selling this asset and you're highlighting some of the reasons that we're selling the asset.

ROBERT PEABODY:

It's low.

ROB SYMONDS:

It's about 30% I believe, today.

PAT ROCHE:

Okay. Okay, that's all my questions. Thanks.

ROBERT PEABODY:

Super.

OPERATOR:

This concludes the question-and-answer session. I would like to turn the conference back over to Mr. Rob Peabody for any closing remarks.

ROBERT PEABODY:

Thanks for your questions everyone.

I'll close out by saying that our 2018 program is a continuation of the five-year plan we set out at Investor Day.

We are ahead on almost all the targets we set for ourselves at that time.

In 2018, we're really reaping the benefits of the transformation of our asset base that's been underway for a number of years.

Using the pricing outlined by Jon in his section, we expect to generate more than \$4 billion of funds from operations and about \$1 billion of free cash flow. Our ongoing investment in a deep inventory of low-cost projects will further reduce the commodity price at which we break even.

Finally, following the Superior Refinery acquisition, we are still maintaining our strong balance sheet.

We'll be providing another detailed update on the five-year plan at our next Investor Day, which we plan to hold in May of next year. Meanwhile, I look forward to talking to you all about our fourth quarter results in about 12 weeks' time.

Once again, thanks for joining us and best wishes for an enjoyable festive season.

OPERATOR:

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