



## HUSKY ENERGY

# 2018 INVESTOR DAY WEBCAST TRANSCRIPT

**Date:** Tuesday, May 29, 2018

**Time:** 7:00 AM MT / 9:00 AM ET

**Speakers:** **Rob Peabody**

President and Chief Executive Officer

**Janet Annesley**

Senior Vice President, Corporate Affairs

**Jeff Hart**

Acting Chief Financial Officer

**Rob Symonds**

Chief Operating Officer

**Jeffrey Rinker**

Senior Vice President, Downstream

**Andrew Dahlin**

Senior Vice President, Heavy Oil and Oil Sands

**Carmen Lee**

Vice President, Oil Sands

**Gerald Alexander**

Senior Vice President, Western Canada

**Trevor Pritchard**

Senior Vice President, Atlantic

**Bob Hinkel**

Chief Operating Officer, Asia Pacific

**ROB PEABODY:**

Good morning. If we get started on time, we can finish close to on time, that's the plan. Okay, thanks. Thanks, everyone, and thanks for coming out this morning. I see a lot of familiar faces, already met with a few of the people we had here last year, as well, and a few new ones.

Before we begin with the formal presentation, I wanted to take some time to talk about Husky's process and occupational safety. Last year, we experienced a near-miss situation at the SeaRose. An iceberg entered our ice exclusion zone and we didn't follow our own procedures to disconnect the vessel, judgment was applied when no discretion was allowed for. A few weeks ago a fire broke out at our refinery in Superior. Thirteen workers were injured and treated, and they were all treated and released from hospital. We remain committed to our employees and the Superior community, and while it is still too early to talk about a schedule for return to operations at the refinery, the investigation continues and we're working cooperatively with regulators and government officials. The commitment to safety and operational integrity has always been at the core of Husky's operations, it actually underpins the entire business, but these incidents show there's still more to do.

We spent the last decade building a program for process and occupational safety at Husky and we've made good progress. The foundation of our approach is the Husky Operational Integrity Management System, or HOIMS for short. The system guides our approach to managing risk, including health, safety and environmental performance. It integrates both occupational and process safety into one comprehensive management system. HOIMS is based on 14 elements. It starts with leadership and commitment, and includes risk assessment and management, safe operations, reliability and integrity, environmental stewardship and performance assessment, as well as continuous improvement. As we redouble our focus on safety, HOIMS will continue to be the foundation of our approach.

So, what additional steps are we taking?

First, we're aligning our compensation more tightly with our safety performance. As a result of last year's near-miss in the Atlantic, our 2017 employee bonuses were capped for all employees, including myself. Going forward, that link will be more explicit and set out in our Management Information Circular.

Second, the executive in charge of process and occupational safety will report directly to me.

Finally, we're working with a group, with an organization called the High Reliability Group. This company is led by former U.S. nuclear submarine Commander Bob Koonce. Bob's team works with companies to improve their operational integrity and reduce risks through better safety and compliance practices, with a particular focus on how procedures are followed. This includes adhering to the principles of leadership, culture, integrated management systems and systematic feedback programs. Essentially, we're looking to incorporate the operating practices of the U.S. nuclear navy into our operations.

As our changes take effect—and they're already underway—the results we deliver will be measured and reported. In closing, we know the critical importance of safety for Husky and compliance will never be an option.

Thanks, and I'll now invite Janet Annesley, our Senior VP of Corporate Affairs, to outline the agenda for the day.

**JANET ANNESLEY:**

Thanks, Rob. Our format today will be very similar to last year, and we have some new updates to our five-year plan to share with you, but before we get going on the main presentation, and in line with Rob's remarks on safety, a couple of important items. First, the emergency exits are clearly marked, and if the need arises, please look for the hotel staff to guide you, and now if you could please check your cellphones and turn them to silent for the duration of the presentation. Thank you.

Here's our agenda for today. Rob will outline how we've been delivering against our strategy and the five-year plan we laid out in 2017. He'll also provide an update on this plan out to 2022. Then, I'll come back and talk about our approach to environmental, social and governance priorities. Jeff Hart will drill down into our financial framework. This will include the ongoing improvements we've been making in our cost structure and how we think about allocating our growing funds from operations and free cash flow. Next, Rob Symonds will provide an overview of our operations, including how we're driving efficiencies across the business. Following a short break, we will hear from Jeff Rinker, Andrew Dahlin, Carmen Lee and Gerald Alexander, each of whom will provide an overview of the components of the Integrated Corridor, which are the

Downstream, thermal production and resource plays, respectively. Finally, Trevor Pritchard and Bob Hinkel will take us through the Offshore business in the Atlantic and Asia Pacific regions.

Today's presentation, including a break, will take just over two hours. Then, we'll open up the floor to your questions. After this morning's session, there will be an opportunity to network with members of the Management Team.

Your package today has a detailed appendix, which includes all the price planning assumptions and other slide notes. It also includes forward-looking information. Unless otherwise stated, everything today is in Canadian dollars.

Now, I'll ask Rob to come back and begin the main part of our presentation.

**ROB PEABODY:**

Thanks, Janet. I just wanted to mention a few new members of our Leadership Team and point them out to you. Many of you will already know Jeff Hart, who's now our Acting Chief Financial Officer. Jeff's been with our team for more than eight years now. Our SVP of the Downstream is Jeff Rinker, who spoke to you last year about the integrated value chain. Trevor Pritchard is now leading our Atlantic business, our Atlantic operations, you'll hear from him in a bit, and Carmen Lee is our new Vice President of Oil Sands and she'll be providing an update on our Sunrise operations.

Let's talk first about our value proposition. Our strategy remains on track. We are continuing to invest in a deep portfolio of low-cost projects. Each of these projects has to generate a return of at least 10% at a flat \$45 WTI oil price. Our WTI earnings breakeven is already low at \$42 and our investments continue to drive it even lower, and as our cost structure comes down and our production increases, our funds from operations and free cash flow are growing. This means we can reinvest in our low-cost portfolio and, as a result, compound returns. It also allows us to grow our dividend as we improve our asset base. At our price assumptions, after funding the dividend and the CapEx program, we still expect to have excess free cash flow. One important point, with our strong balance sheet, the tight physical integration of our Upstream and Downstream businesses, and the stability offered by our term contracts in Asia, we're both resilient to market conditions and well positioned to take advantage of upside.

Over the next few slides, we'll see what sets Husky apart from our peers. In these charts, you can see the kind of seismic changes—and I like those, because they look a little bit like seismic lines, if you use your imagination—to commodity prices we've seen over the last number of years. History has taught us that there are many variables at play and conditions can change abruptly. Whether it's trade wars, geopolitical tensions, developments in the Middle East, transformational technology or natural disasters, these emerge regularly to shape energy markets. So, here's how we protect ourselves from these developments while still growing our business.

First, we start with a strong balance sheet. There's no shortage of examples of companies that have been wiped out because they were caught off guard during unforeseen events. We view our strong balance sheet as a built-in shock absorber, and, as you can see here, we have one of the strongest financial positions amongst our peers.

Second, we believe in the power of integration, particularly if you're a heavy oil producer in Western Canada. We understand the important role of integration in capturing full value, a good reason why we invested in the Lloyd upgrader back in the early '90s and the Lloyd refinery before that.

Over the years, we've expanded and developed our approach to integration to eliminate quality and location price differentials for our heavy oil and bitumen. In fact, we have one of the lowest—we have the lowest, I think it's fair to say, exposures to these differentials compared to our Canadian peers. We are also closely matched on our Upstream heavy oil blend versus our Downstream processing.

Beyond that, we have further capacity to export heavy oil barrels via pipeline to higher priced markets in the United States. Our North American gas production is minimally exposed to current discounts in AECO due to our connectivity with the U.S. markets. For example, if you include the benefit of our space on the Northern Border Pipeline, our average realized gas price was about \$3.50 per mcf in the first quarter of 2018, versus the AECO benchmark which averaged about \$1.85. Furthermore, the amount of gas we purchase for use in our thermal and refining operations roughly equals the amount of gas we produce in Western Canada, giving us a further level of integration, the difference being we purchase this gas at an AECO-related

price while we sell at a price higher than AECO because of our connected pipeline capacity to the U.S.

Looking ahead, we believe our integrated model will continue to play a pivotal role, particularly in regard to our outlook for our Downstream segment. Jeff Rinker will take us more deeply into this structurally advantaged business after the break. In our case, we essentially capture Brent pricing for our heavy oil and we are largely insulated from AECO. Finally, throughout that whole value chain, we are working to reduce cost of manufacturing along the whole chain, from Upstream through into the Downstream. It's a constant focus.

Husky is one of the few publicly traded North American oil companies with exposure to the fast-growing energy markets in Asia, another thing that sets us apart. While the rest of the Canadian industry waits for pipeline access, improved infrastructure or LNG construction, we are already well established in Asia, and we have strong partnerships there. The growing amount of income being generated by our term contracts in the region is contributing to a more stable and predictable cash flow. These contracts deliver gas pricing that is, on average, about five times the price currently seen in North America. We expect to see this segment of our business produce about 20% of our funds from operations over the course of the plan, keeping pace with the growth of the rest of the business, and you see that in this chart here, it's about 20% through '18 through '22. It's growing marginally, but the whole portfolio is also growing. The door to Asia continues to open, and later this morning Bob Hinkel will talk about how we find gas on the doorsteps of markets that need it and then pipe it directly to the customer. He also has some interesting news about our new oil discovery in China.

Moving to the next point, we have a low sustaining capital business, which means we have more free cash flow to deploy elsewhere. We're investing in the type of business that needs low amounts of sustaining capital; namely, growing our thermal business. We are the industry leader in small-scale thermal development. Lloyd and Tucker account for about one-third of our overall production today and require just \$6 per barrel of sustaining capital. Overall, we've reduced our annual sustaining capital requirement by more than \$1 billion since 2014.

Looking forward, we have six Lloyd thermal projects under construction, representing 60,000 barrels per day of new capacity. Beyond that, we've identified another six projects. When you add in the ramp-ups at Tucker and Sunrise, we expect thermal production to be just over

200,000 barrels a day by the end of the plan period, which will by then be about half our overall production. There, you can just see this growing to about half of our thermal production in the plan period.

Lastly, we believe the producer with the lowest price breakevens comes out ahead. This has been a large focus for Husky over these last few years as we've reduced our earnings breakevens to amongst the lowest levels in the industry. We've done this by focusing on a unique portfolio of projects that can increase our margins. Instead of investing solely in one segment, like Oil Sands, we take a broader approach to the portfolio, advancing projects that offer the lowest cost of supply. The average operating cost of our new Upstream projects are around \$9 per boe. Through these investments, we are further reducing our breakevens.

So, to pull this all together, this is what sets us apart. We have a strong balance sheet, the cash flow generating ability of our heavy and bitumen production is shielded from the location and quality differentials through integration, our high netback gas production in Asia is sold, on average, for about five times AECO gas prices at largely fixed prices, we are a low sustaining capital business, and we have one of the lowest earnings breakevens in the industry. As you see on the chart on the right, most of our production is either protected through integration or has direct access to global market prices.

In the next couple of slides, I'm going to speak a bit more to our strategy. We subscribe to the view that companies who are the most successful in the long term have built-in sustainable competitive advantages. Warren Buffett would say they have moats. Both of our businesses, the Integrated Corridor and Offshore, have these moats.

In the Integrated Corridor, we have an unmatched land and infrastructure position at Lloyd, we have a gas business that feeds our thermal plants and refineries, and we have a sizeable Downstream segment that maximizes the value of our Upstream barrels that allows us to benefit from market dislocations. It would be very difficult to replicate this level of physical integration, secure long-term transportation capacity, product outlets, and the ability to upgrade and refine in both Canada and the United States with as much optionality as we have.

In our Offshore business, any North American oil company would be hard pressed to replicate our business model in Asia. We have longstanding partnerships and term contracts in the

region, and immediate access to those markets, an enviable position. In the Atlantic region, where we have operated for many years, we have an established track record. This business has earned some of the highest returns in our portfolio since its inception.

A big part of our story is our focus on becoming a low-cost producer, and we've done this through a classic shrink-to-grow strategy. Since 2014, we've sold more than 50,000 barrels of oil equivalent per day of production, mostly in higher cost assets in Western Canada. This has allowed us to focus our attention on investments in higher margin production, such as Lloyd thermals and our projects in Asia. The result was a fundamental structural transformation. Just for comparison, about 20% of our production in 2014 had operating costs below CAD\$11 per boe or about US\$10 per boe. Today, that's more than 60% under that \$11 ceiling. The result is an overall reduction in Upstream operating costs of 23% over the past four years, and that just shows that progression in low operating cost production. We've done the shrinking and are now well positioned for growth.

We've also simplified our business. For example, we've reduced the number of operated wells in our Western Canada production business, from over 31,000 gross wells down to about 6,000. Andrew and Gerald will talk about how we are also gaining efficiencies by centralizing our operations in these regions. We've also become more resilient to industry cost inflation. A few years ago, we needed more than 40 rigs just to keep production flat. Today, we need less than 10 rigs to grow our production at about 7% per year, which minimizes our exposure to rising service costs. Once again, this is largely because we have shifted the nature of our production. We are doing less drilling in conventional businesses, like CHOPS, and moving more towards low-decline thermals and Asian gas.

These charts show how we stack up against a globally integrated peer set and demonstrate the results of our strategy execution. Starting from the top left, up here, we are one of the lowest cost producers in terms of operating cost per boe. At the top right, over here, our focus is on lower sustaining capital and projects with lower operating cost. This has resulted in a substantial decrease in our required breakeven oil price. The continued improvement in our project inventory is reflected in the graphic on the bottom left, which shows we are comparable or better than our peers in regards to cost of supply.



All this brings us to 2017, which was our first year of a five-year plan that we set out a year ago at the same event. As you can see, we met or exceeded all the commitments in this plan. In particular, free cash flow came in at \$1.1 billion—up here, free cash flow, \$1.1 billion, or \$350 million more than expected. This is largely the result of coming in lower on CapEx, which was partially due to deferring the asphalt refinery at Lloyd, but also, due to increased efficiencies, we were able to increase the scope of the work we got done, essentially, with less capital, getting more done for less. Operating costs, shown here, per barrel also came in lower than expected. Meanwhile, we made good progress on the project and operating front, and you can see some of our highlights on the left side of this slide. This includes the sanction of West White Rose, a third field at Liwan and two additional Lloyd thermal projects.

This is our updated five-year plan from 2018 to 2022. This plan was put together using generally the same price deck as we used last year. It assumes US\$60 WTI for the rest of this year and \$60 flat for every year thereafter. The only tweaks to the pricing assumptions were to widen the heavy/light differential and to lower our AECO gas price assumption to be more reflective of current reality. Of course, neither of these had any impact on our overall results, which speak positively to how we're configured to be insulated from North American oil and gas price differentials.

The key outputs are summarized in the table on the right, and I'll go through a few of them. Starting with funds from operations, which is on the left-hand side of the slide, over here, last year's plan is highlighted in light blue, so you can compare with the updated version on an apples-for-apples basis. As you can see, our funds from operations will grow from over \$4 billion this year to \$5 billion by the end of the plan, an increase of 25% with the same \$60 flat pricing scenario.

Here are some other features of the plan. Production growth in last year's plan was about 5% compounded, shown over here. This year, our five-year CAGR outlook is about 7%. Admittedly, this is now starting from a lower base due to the asset sales we completed late last year. We're also growing our Downstream heavy processing capacity, and Jeff Rinker will take you through the details in his section, which is right down here.

If you look at the changes in free cash flow versus last year's plan, you'll notice a reduction in 2019, which is shown right there. The biggest factor in the change in free cash flow is the

difference in the timing and amount of our growth spending. We deferred some capital spending from 2018 into 2019 at Liwan, and we also upped our stake, as we previously announced, from 49% to 75% in the 29-1 field at Liuhua. In Indonesia, as we previously signaled, we expect a slower completion schedule for our series of M fields in the Madura Strait. They're still progressing, just a little slower. In Western Canada, as I've said, we've sold some assets late last year that were not contemplated in the previous plan. 2018 free cash flow is up, reflecting mostly improved pricing and some of the capital movements I spoke about earlier. In terms of Upstream unit operating expenses, we anticipate a 15% reduction over this plan, and for sustaining capital, our expected annual average is about \$1.9 billion, on average, growing more as you go to the back of the plan as production increases towards and beyond 400,000 barrels a day.

Here's a quick look at our cash flow sensitivities as oil prices increase, or if they increase. It starts from our base plan of a flat \$60 WTI and then it just shows you cases for \$70 flat and \$80 flat. There's a point to be made here. The last time we generated funds flow from operations of over \$5 billion was 2014, with WTI averaging US\$93 per barrel that year. Today, with the reduction in our cost structure, we expect that we could do the same at \$80 WTI, and as we continue to grow production and margins per barrel, by the end of the plan, in 2022, we expect to be able to generate \$5 billion in funds from operations at \$60 WTI.

To summarize, we successfully completed the first year of our five-year plan. Our structural transformation continues to deliver results. The asset base has been transformed, with a focus on higher margin production, secure transportation access and growing flexibility of our Downstream business. The investments we've been making in the Integrated Corridor and Offshore businesses are further reducing the oil price we need to achieve earnings and cash flow breakevens, which in turn is increasing our funds from operations and free cash flow. Our plan provides for a dividend which can grow with improvements in our underlying asset base, and our tight physical integration and term contracts in Asia are contributing value and cash flow stability. Our plan is also underpinned by a strong balance sheet.

Just before Janet takes us through our environmental, social and governance approach, or ESG in the new nomenclature—I didn't even know what that stood for three years ago or so, but I'm an expert now—I'd like to share a few thoughts on this subject.

The markets and our shareholders are both interested and engaged in how we operate in a world with higher environmental, regulatory and social expectations. As a result, we took steps last year to further improve our reporting with a formal ESG strategy. We're continuing to evolve our governance procedures in line with best practices and with an eye to continuous improvement. This morning, we released our improved and newly named ESG Report—I think it used to be called the Sustainability Report. You'll find copies in our reception area here today, they're at the back of the room, and we'll move a few more out to the door when you leave, so you can't ignore them. It's also posted on our website. The report includes disclosure on topics we believe have the most impact on our long-term sustainability and success.

Looking forward, we believe hydrocarbons will play a critical role in supplying energy to the world for quite some time. Demand for energy and petroleum products is set to rise for at least a couple of decades, driven by population growth and a growing middle class, and it's likely to stay on plateau for several decades beyond that. Our products, namely, natural gas, gasoline, diesel, jet fuel, petrochemical feedstocks, are helping to meet this demand. Our industry remains a key source of jobs, government revenues, technology, while providing essential and affordable energy products. If Canada chooses not to meet this rising market demand, oil and gas production will simply migrate to other jurisdictions that, in general, have lower environmental standards, less stringent environmental regulations, and that place a lower priority on human rights and diversity. Ultimately, it is our purpose to responsibly produce our products that are needed by society for the benefit of all our shareholders and our stakeholders.

Thanks very much and now we'll hear from Janet.

**JANET ANNESLEY:**

Thanks, Rob. The energy transition tends to dominate the energy conversation lately, but as Rob pointed out, we believe hydrocarbons will continue to be an important source of energy for many decades to come. At the same time, we do understand the need to take action on climate change and to improve air, land and water related environmental performance. Our starting point is the recognition that we have a role to play in delivering essential products the world needs and we must do so in a safe and responsible manner.

We must also respond to the changing needs of markets, customers, stakeholders and, of course, investors. Increasingly, we are asked what are we doing to manage environmental,

social and governance performance, and whether we are achieving results. To address these questions, we released our 2018 ESG Report this morning. This annual report is part of our commitment to make our ESG reporting more accessible, timely and transparent. Husky is not new to safety, environmental and community reporting, but as mentioned earlier, we have now formalized our risk assessment and ESG management strategy to ensure we're meeting the changing needs of investors and stakeholders.

This strategy development process included a materiality assessment which identified areas of importance to us and to our stakeholders. This includes assessing the risks and prioritizing topics we believe have the greatest impact on our long-term success. These topics, which are grouped under these five categories, helped focus our strategy and formed the basis for this year's ESG Report. We want to ensure all stakeholders get the information they are looking for, and it's clear that more information on how Husky is managing safety and ESG performance is high on that list.

Rob has talked about the changes we are making to build our safety culture. We are taking a similar approach to our environmental performance and our disclosure in key elements, such as carbon and water, as ranked within the industry's top-quartile group. Energy use and ESG performance are important to Husky, and you'll hear more this morning about some of Husky's projects, but I'll just list a few examples.

At Lloydminster, we've been capturing CO<sub>2</sub> at our ethanol plant for six years. At the Pikes Peak South thermal project, we are continuing to test new carbon capture technology. Across our other thermal projects, we are reducing steam to oil ratios and improving our energy intensity, therefore reducing the carbon intensity of each barrel produced. As an example, you can see the SOR trend at Sunrise and at Tucker. At the Ansell resource play and in our CHOPS operation in Western Canada, we are piloting technology to reduce methane emissions, and in Asia, we are supplying cleaner burning natural gas to local markets, improving air quality for millions of people.

While improving our safety and environmental performance are priorities, so, too, is social performance. Husky has more than 5,100 employees in Canada, the U.S. and the Asia-Pacific region, and we support a diverse, respectful and inclusive workplace across our businesses and locations. Good jobs are important to communities. In addition to working hard to be a good

employer, Husky has forged enduring relationships with many community groups, that enhance local quality of life through social services, improved healthcare and educational opportunities.

Earlier this year, we launched the Husky Employee Community Service Grant Program. This program provides funding to community organizations with which Husky employees regularly volunteer. We know that aligning Husky's dollars with where our employees choose to volunteer their time makes communities even stronger.

Husky has also developed Indigenous Awareness Training and an Economic Inclusion Program. These both foster Canada's broader societal goals of economic reconciliation and support their community goals. This program is being rolled out this year. Engagement with Indigenous communities in areas where we operate is part of our practice and policy, recognizing rights and reconciliation. We focus on building capacity with Indigenous businesses to establish their competitiveness. We do this by providing opportunities to deliver goods and services on a competitive basis, with contracts awarded on the basis of technical and safety criteria, as well as on price.

I invite you to pick up our ESG Report. As Rob mentioned, they're at the back of the room, and we'll make sure they're available on your way out and also online, and please feel free to share your thoughts with our Investor Relations Team at the break.

Thank you very much. Now, I'll turn the floor over to Jeff Hart to speak to our financial framework.

**JEFF HART:**

Thanks, Janet. Good morning, everyone. As you know, our priorities don't change from year to year. What does change is the emphasis we place on each of them. A few years ago, our focus was to strengthen the balance sheet. We accomplished this in 2016 and 2017. Another focus was to structurally transform the Company. We did this through select legacy asset sales and making investments in the types of projects that we lower the oil price required to break even, resulting in an increase to our margins. We've made good progress. The investments we've been making in the Integrated Corridor and Offshore businesses have brought our WTI breakeven down to the point where it is one of the lowest in the industry, and now we're in a

position to generate significant free cash flow which can be returned to shareholders and reinvested back into the portfolio to further compound returns.

Now, before we get into detail on the financial framework, I'll run through our pricing assumptions. The table at the top shows last year's planning assumptions and in the middle is our 2018 base case. It's generally unchanged at a \$60 flat WTI, but with wider heavy differentials and lower AECO pricing to reflect today's reality. We recognize oil prices are higher today, so you'll also see some charts showing our cash flow at both US\$70 and US\$80 WTI. The bottom table shows our stress case at US\$35 WTI, which I'll also speak to.

The right-hand of this slide shows what underpins our financial framework. It's all predicated upon the cash flow that our assets can deliver at the bottom of the cycle, and that triangulates to being able to cover our sustaining capital requirements, dividend payments and to stay within our target debt ratios. We peg the bottom of the cycle at US\$35 WTI. This doesn't mean we expect to see \$35 oil, it's what we use to ensure our resilience in any price scenario. Today's asset base can generate about \$2.1 billion annually at \$35 WTI. It's enough to cover our annual sustaining capital requirements of \$1.8 billion and the current dividend. In terms of debt, we like to maintain a ceiling of no more than two times net debt to funds from operations at the bottom of the cycle.

As we continue to execute the capital program and improve the cash-generating ability of our asset base, these numbers all start to expand. By 2022, at the bottom of the cycle, we expect to be able to generate about \$2.9 billion in cash flow. This is enough to cover our sustaining capital requirements, which will be about \$2.2 billion at that time, leaving us about another \$400 million to allocate in excess of the current dividend, and given the expected funds from operations, there's further capacity on the balance sheet to go up to about \$6 billion in net debt.

For us, it's fundamentally about margin expansion through growth and higher quality Upstream production and projects to improve Downstream margin capture. This illustrates how the transformation of our asset base continues to improve Husky's cash-generating ability between 2017 and 2018. On this slide, you can see a bridge from last year to our expected FFO this year, and even though we've seen a meaningful improvement in commodity prices, it's only responsible for about 45% of the increase. The balance is largely coming from the addition of

new, higher margin production in the Upstream, higher gas sales in Asia and the addition of new refining capacity.

Of note, this chart and all others showing our funds from operations are inclusive of the Superior results, and also note that we have comprehensive insurance coverage in place which includes business interruption, property damage and third-party liability coverage.

Now, let's look at the next five years. This chart shows the cash flow over the plan. It's based on our \$60 WTI pricing scenario. It's interesting to note that funds from operations is evenly distributed across three sources, the Downstream, the Upstream portion of the Integrated Corridor and our Offshore businesses. As Rob described, each of these businesses have built-in advantages that increase the stability and predictability of our cash flow. In the Corridor, we can mitigate volatility by owning or operating the whole value chain. For example, when differentials are wide, the Upstream cash flow decrease is captured in the Downstream business, and when differentials narrow, the opposite is true. In the Offshore, we benefit from term contracts in Asia and Brent-like pricing in the Atlantic, both of which generate strong netbacks. At \$60 flat, our funds from operations will grow from about \$4 billion this year to \$5 billion in 2022.

Here's how we plan to prioritize spending of these funds. Our number one priority is the strength of our balance sheet. We're already below one times net debt to funds from operations and well below our internal debt targets. We don't foresee the need to apply any funds towards deleveraging the balance sheet.

Now, a bit more on our balance sheet. Our financial flexibility remains strong. Our net debt position includes over \$2.3 billion in cash and more than \$4 billion in unused credit facilities. On the top right of this slide, as I mentioned, we want to remain below two times net debt to funds from operations at the bottom of the cycle, and as of Q1, we are well below that target, with about \$1 billion of cushion. Looking into 2022, to stay within our target, we would have the capacity to be at about \$6 billion of net debt. In terms of debt maturities, we have \$1.2 billion maturing in 2019, and we are maintaining our strong investment grade credit position. On a net debt to trailing FFO basis, we have amongst the lowest leverage of any of our peer group.

Back to our spending priorities. Our next priority is to spend what's required to sustain our assets. To us, that means keeping Upstream production flat and ensuring all of our assets are kept in safe working order. We estimate our annual sustaining capital requirements will average about \$1.9 billion over the plan. That's about \$1.8 billion this year, rising to about \$2.2 billion in 2022, and this figure rises along with our production.

Here's how we arrived at our 2018 sustaining capital numbers. In the Upstream, our decline rate is about 17%. This means to stay flat, we need to replace 53,500 barrels per day annually. Our average cost to replace each flowing barrel is about \$21,500, which gets us to \$1.15 billion. Adding in basic maintenance capital of about \$150 million, our total Upstream sustaining capital is \$1.3 billion. In the Downstream, sustaining capital is \$500 million per year, including regular maintenance and turnarounds. This brings our sustaining capital requirement in 2018 to \$1.8 billion, and we've given you the numbers to apply the same methodology to 2022.

Our next priority is to maintain the base level of dividend. When we announced the dividend earlier this year, we said it would be sustainable through market cycles. It was deliberately set at a level to withstand \$35 oil and to be able to grow over time in tandem with improvements to the underlying asset base.

Now, we move to our growth capital spending. We're spending an average of \$1.5 billion per year on growth, and this is serving a few purposes. It grows production, increasing our top line revenue, and because of the types of projects in which we invest, CapEx also drives down our cost structure. I'll note that our capital spending figure includes all corporate capital, but does not include capitalized interest of about \$150 million per year through the plan. Essentially, our capital spending program is driving our margin growth, and this shows how it is further improving our cost structure. Everything we consider must meet the hurdle rate of 10% after tax at US\$45 WTI and it must breakeven at \$35. This ensures that our investments continue to reduce our cost structure. Our earnings breakeven over the next five years is expected to go from \$42 per barrel today to \$37 per barrel at the end of the plan, and per barrel op costs are expected to come down another 15%, from \$13.50 today to around \$11.50 in 2022.

This brings us to a materially more competitive position. This is why the CapEx program is so important to us, and it is truly a five-year program, with only minor tweaks year-over-year. If oil prices go up, we don't want to substantially increase organic growth spending, as we risk losing



efficiencies, and if prices go down, our current growth program is protected by using the room we have on the balance sheet. The other aspect of our CapEx program is that it's relatively de-risked. Two-thirds of our capital is directed towards short- to mid-cycle projects; meaning, less than three years from project spend to first cash flow.

Lastly, at our price planning assumptions, we generate discretionary free cash flow above and beyond what is required to fund our sustaining capital, the dividend and our growth program. This year, we expect about \$1 billion in free cash flow before dividends. With higher growth spending in 2019, there's a decrease, and then we resume the free cash flow trajectory to the end of 2022, with about \$1.4 billion using our pricing assumptions. Of course, this reflects our assumptions of a flat US\$60 WTI, and we are higher than that right now. This will give us cumulative free cash flow over the plan after paying our base dividends of \$3.3 billion at \$60 WTI.

This is how we think about the options to allocate this free cash flow. First, the balance sheet. Probably, the biggest differentiating factor between us and our peers is that when we bring free cash flow in the door, we're not obligated to allocate any funds towards leverage reduction. This leaves more room for other value-enhancing initiatives. Next, we can grow the base dividend. As we've demonstrated, the framework used for the base dividend allows it to be increased over time in tandem with our improving asset base. Special dividends and share buybacks also remain options. In terms of organic growth, for the reasons I've just laid out, it's unlikely we will accelerate spending substantially. In regards to inorganic growth, first, it needs to be on strategy, secondly, it needs to fit within our financial framework.

So, to wrap up, we will continue to triangulate balance sheet strength, sustaining capital coverage and dividend affordability through the commodity cycle. The goal of our CapEx program is to lower our cost structure and increase our margins, so we will tailor our investments to projects that bring down our breakevens. These projects, in turn, will increase our funds from operations and free cash flow generation even under flat commodity price assumptions. This will allow the dividend to grow over time as the asset mix continues to improve.

Thanks very much. Rob Symonds will now take us through our operations and overall project objectives in the Integrated Corridor and Offshore businesses.

**Rob Symonds:**

Thanks, Jeff, and nice to see so many familiar faces in the audience today. I'd like to start off my remarks with a look at the Integrated Corridor. Boiling it down, this Corridor is an interconnected value chain that manufactures refined finished products which we sell across North America. The raw materials that feed this chain originate in that large heavy oil and gas resource base businesses that we have in Western Canada, and then they move through our own transportation, storage, refining systems to make synthetic oil, asphalt, jet fuel, diesel, gasoline and petrochemical products. We produce enough natural gas to offset the consumption in our thermal operations and Downstream facilities. The Corridor is purpose-built to capture margins from the reservoir all the way down to the refinery rack, regardless of the heavy/light and Canada/U.S. differentials. Effectively, margin capture of the Corridor is largely tied to global or Brent-like pricing, and as we've said earlier, because of the way we're set up, we're virtually agnostic on oil and gas differentials. Let me show you why that's the case.

Now, we all know the first quarter of this year was a tough one for many heavy oil producers and it really put our Integrated Corridor to the test and it proved it's mettle. What you have here on the screen is a chart that's bridging us from Q4 of 2017 to Q1 of this year, and while our Canadian Upstream heavy oil production was challenged, certainly, by wide differentials, we were largely shielded. The reduction in funds from operations in the Upstream heavy oil business is shown here in the red bar, but what you're also seeing over here in the green bar is that the bulk of that was picked up in our Downstream business in the Canadian refining and export pipeline access that we have.

I will note that this chart is only showing the Canadian refining and I&M segment results. If we added to this our other U.S. refining assets, including what we capture from Toledo, Lima, and in Q1 at Superior, we would see that we are essentially offset against that differential.

Now, a big part of avoiding the Canadian heavy differential this past quarter was our ability to move our molecules to the United States. We captured most of this gain through our access to pipelines, including our committed capacity on the existing Keystone line. Now, this gain is recorded within our Infrastructure and Marketing segment, and that segment delivered an EBITDA of \$190 million in the quarter, which was almost double the same quarter of last year.

Let's have a look now specifically at the Lloyd refining complex. This complex provides us an important competitive advantage by capturing the entire value chain. Our Upstream feedstock from thermal oil is very low cost. Operating costs at our thermal operations average between \$10 and \$12 per barrel, and while the non-thermal operating costs are certainly a little higher, as you can see here, overall op-costs are still under \$15 per barrel. Transportation to move this crude into the complex is under \$2 per barrel.

One fact on the complex, the upgrader produces two main products, Husky synthetic blend and ultra-low sulfur diesel. Both of those, of course, are fungible products in our Western Canadian orbit. The refinery produces two main products. High-quality asphalt that we move by rail to market and to our terminal network throughout Western Canada. It also produces intermediate feedstocks for sale or further processing in the upgrader. In the latest quarter, as you can see here, we realized a full value chain netback of over \$47 per barrel. That compares with—when you look over here on this side of the chart, what you see in the blue is the Upstream netback. So, the Upstream netback would have been \$14 per barrel if sold at the wellhead. So, that's a \$33 gain by running the heavy oil through the Lloydminster complex.

Let's do the same analysis for Toledo, the Sunrise to Toledo integrated system. You can think of Toledo as a combined upgrader and refinery. It converts heavy oil all the way to finished products. We're configured to transport Sunrise crude directly to this 50% Husky-owned heavy oil refinery where we produce gasoline, diesel and other products. Now, Q1 was a really tough quarter due to the differential in the bitumen space, and you can see here on the bottom left here we had negative netbacks in the Upstream, we lost some \$5.62. However, this was offset by the value capture that was obtained as we got it to Toledo, and you can see the full value chain netback as a result of that was \$24 per barrel.

Now, I've taken you through the barrels that do have a home in two of the refineries that we have and now I want to highlight one of the options that we have for remaining barrels. As we said, we have some 75,000 barrels per day of long-term firm export capacity on the existing Keystone line. When combined with our refining capacity, it can give us the ability to clear all of our heavy oil production. This has been especially valuable in the recent environment of wide Canadian heavy differentials.

So, what you're looking at here on the right-hand side of this chart is the differential between WTI/WCS diff at Hardesty, some \$32 a barrel, and what you can get for that same barrel at Cushing, which was under \$10 of the differential. So, that's a \$23 location differential that occurred in the first quarter. You can see the typical transportation costs to get from Hardesty to Cushing, something in the order of a little under \$9 a barrel, \$8 and change. So, that says there's a \$14 incremental differential available for capture, and we've booked a significant portion of that gain in our results from our I&M, Infrastructure and Marketing business in Q1.

Now, in times when the differential is not as wide, the Keystone capacity can be used to move other products, whether that's synthetic crude or other products, down to the south, either for sale or to feed our own refineries, and Jeff Rinker will take you through some of the optionality that we have later on, but essentially, when the differential is wide, we are in a position to capture that location differential.

To summarize for the Corridor, we're continuing to lower costs and maximize margins along every link of the value chain. As mentioned earlier, we've made several structural improvements. In heavy oil, we've pivoted away from CHOPS towards lower cost thermal projects; in our Resource Plays business, we've completed our transformation and we're now focused on larger, more economic plays; and in the Downstream, we've been heavying up our refineries in the U.S. Midwest, giving them more flexibility to capture those margins; and all of these business are growing. But, in addition to the structural improvements, we're looking at efficiency improvements, as well, to squeeze out more value through concentration, standardized design and consolidation, and I'll give you a few examples.

Along with a clearer focus in Western Canada, we've created three activity hubs, at Edson, Grande Prairie and Rainbow Lake, and these can utilize existing infrastructure and support our operations in a more cost-effective manner. Gerald will take you through and give you some more colour on those hubs in his section. We're using the same idea in the heavy oil business, where we're developing projects in clusters around single hubs. For example, we're developing activity hubs at Spruce Lake, Dee Valley and Edam, and Andrew will take you through some more of those details in his section. In the Downstream, at Lima, we've been taking middle distillates and introducing them partway through the refining complex, so bypassing the crude unit, and later Jeff Rinker will give you some more context to how we optimize the units within the refinery. In addition, we are now marketing our own refined products, and by grouping

production from Toledo, Lima and Superior together, we're able to realize better value for our end products. On the right-hand side of the slide, you can see the outputs of these efficiencies reflected in our anticipated free cash flow profile for the Corridor.

Next, turning to our Offshore business, our two operational areas in Asia-Pacific and the Atlantic both continue to generate high netbacks. Our approach here is to pace these projects in each region, so they complement each other. As one side is developing, the other side is being harvested. So, if you think about this at a high level, as we were harvesting the cash from Wenchang, we were investing in White Rose, as we invested in Liwan, we harvested from White Rose and Wenchang, and today, as we harvest from Liwan, we're investing in both West White Rose and in Indonesia. So, in short, the cash generated by our main fields at White Rose and Liwan, and eventually West White Rose, feed into this continuous cycle. The result is a synchronized self-funding business that provides for development and also kicks out consistent free cash flow.

Now, there's a common thread in our Offshore business; that is, wherever possible, we utilize existing infrastructure. Some examples. At West White Rose, because we're tying back to an existing FPSO with fixed costs, our incremental operating costs are expected to be very low, reducing the overall average operating costs once the project comes on-stream. At the 29-1 field at Liwan, we're tying back to the existing subsea, offshore and onshore infrastructure. In Indonesia, most of the projects in development are piggybacking along the existing East Java pipeline. That's represented by the red line that's running right through the middle of the blocks here. You can see the discovery block on there. So, we're using that existing pipeline to get us through. The exploration blocks that we have offshore China are also in close proximity to existing infrastructure. In addition, we do benefit from long-term partnerships in both of our regions. In Asia, for example, we work with CNOOC in all of the projects we have to date. They bring a skill set and resource to the table that complements our offshore expertise.

So, this slide summarizes the Offshore business. I'll note this is going out to 2026. Our Offshore business is longer cycle and we tend to put some slides with a little more timeline on them. We like both of the operating areas because of the high prices that they command. In the Atlantic, we typically receive prices north of Brent for our oil, and in Asia, we're selling our gas into the high-demand markets. Now, on the left, you can see the anticipated growth in free cash flow from this segment. On the right, you can see that Asia is appearing to be dropping off in 2021.

However, this doesn't assume any contribution from additional discoveries, such as the one that we have recently announced, and Bob Hinkel will provide us an update later this morning on that discovery, and I'd note we do have further opportunities on the two blocks offshore China that we are drilling this year, and as previously disclosed, we've also recently made another discovery in the Atlantic.

Moving from the two businesses themselves to a key enabler for both of our business, and that is technology. Now, we're very active here, as well. There are a lot of initiatives happening in the industry, and on our slide here you can see a number of things that we're involved in, and these include everything from digital technologies, like big data, artificial intelligence, machine learning, automation, to new chemical and process technologies. At Husky, we look to technology to meet several objectives, and those include improving safety, increasing our capital efficiency, lowering our operating costs and improving our environmental footprint. The list here illustrates just a few technologies that are either in active use, in a pilot stage or being assessed for potential applications at Husky. You'll see some more examples detailed in your appendix, but I'd like to talk a little bit more about one of them right now, and that's machine learning. Now, we're learning from the folks that are very good at these things. We're working with the technology pioneered by companies like Microsoft, IBM, Google, SAS and Schlumberger. A couple of examples on the slide.

On the left-hand side, you're seeing a SAGD example. We're running a pilot program here to optimize our steam/oil ratios across all of our thermal assets. There'll be two further stages following the pilot. In the first, we'll look to implement the technology on a small scale around the end of this year at either Sandal or the Paradise Hill thermal project, and full field implementation is planned in the 2019/2020 timeframe across all of our producing thermal operations. The AI model that we have will use historical data, such as temperature, pressure, chlorates and other factors, as well as the subsurface event, outage and maintenance data, to learn how to respond to events that occurred in the past. All of these learnings will then be used in a predictive model to determine how to standardize future response in real time and eliminate human error, and the expected result is a more efficient and reliable system.

On the right-hand side of the slide here, you see a second example, and this is in regards to sea-states and ice drift predictions in Atlantic Canada. Here, we've been working with Microsoft to build a preliminary machine learning model which uses metocean actual and forecast

weather data. This is going to add further confidence to our offshore forecasting and iceberg drift predictions. The model will include scalable cloud-based virtual machines which will learn from historical data and give us better predictions of sea-state and ice movement. The go-forward project focus will be on improving forecast accuracy and providing the confidence to make better decisions in terms of when we intervene to move icebergs away from our operations, ultimately reaching the potential for increased operational efficiency, with improved utilization of all of the offshore resources, whether they be people, vessels or aircraft.

I'll close up my section with a snapshot of our overall project objectives within the five-year plan. I acknowledge the print on the screen may be a little small, refer to the version in your slide pack, though, to be honest, the print on that one is not all that much bigger, but you can download a bigger version from the website if you need to, but what I wanted to leave you with is the thought that in the Upstream, which is here the Integrated Corridor, shown at the top of the slide, and the Offshore business is shown at the bottom, you can see that we have a number of projects that are either in construction or in their early development stages that go all the way out to 2022. So, you can see the granularity of the projects that are behind the plan that we have put out, and what we have here more than offsets natural decline. There is a net growth in our plan of more than 100,000 barrels a day over the period. In the Downstream, and you can see the Downstream sitting here in the middle, we continue to invest in projects that increase our flexibility to capture more margins. This plan is, though, underpinned by a commitment from me, from Jeff, Andrew, Carmen, Gerald, Trevor and Bob to execute these projects safely and on time.

We're going to take a short break now. After that, Jeff Rinker will be back to give us an update on the Downstream role in our five-year plan. Thank you very much for your attention. See you back here in about ten minutes.

(Short Break)

**JEFFREY RINKER:**

Let's take our seats, please. I think just about everybody is back from the break now, so let's move on to the Downstream section. I just took over as the head of Downstream's business on

the first of May and I spent the first day on my job down at the Superior refinery responding to the incident that we had down there. This wasn't, to say the least, the way I had imagined my first day on the job. Since that day, we've had a lot of serious discussions inside the Downstream Leadership and I can tell you that we're all committed to the safe operations expectations and the actions that Rob laid out in his presentation earlier today, and everything that you'll see here in the Downstream presentation is underpinned by that commitment.

When I spoke to you last year, shortly after I joined Husky, I was really excited about the potential for optimizing Husky's integrated asset base and over the past year I can say that excitement has really just grown. We've been actively shaping Husky's integrated value chain. Our Integrated Corridor is unique in its level of physical connectivity bridging the Canada/U.S. border. By moving our own crude through our own dedicated logistics assets into our own refineries, it sets a baseline or it backstops the value received for our barrels, and it mitigates the risk from the volatility of the location and quality differentials. We currently have crude processing capacity of about 400,000 barrels per day, of which nearly half is devoted to covering the heavy oil exposure. In addition, this integration gives us optionality. We make choices every day on how to best optimize the value captured, through changing our feedstocks, adjusting our product mix, managing the storage levels, and choosing the markets into which we sell our products.

Let's take a tour around the main Downstream assets.

The starting point, in the upper left, is the Lloydminster complex, where our upgrader and refinery with 110,000 barrels a day of heavy crude capacity turning into light synthetic crude, diesel and asphalt, and about almost all of the crude feedstock that goes into Lloydminster are Husky equity barrels. Staying in Canada, we also have the refinery in Prince George which supplies transport fuels to the regional markets in British Columbia.

South of the border, we have a substantial refining presence in the U.S. Midwest. The Lima refinery has, through an increased focus on reliability, demonstrated an operation of 165,000 barrels a day, and this is an increase from the 160,000 barrels per day capacity that we communicated in past Investor Day events. At Toledo, we own half of the 140,000 barrel per day heavy oil refinery, that's been configured to run high-TAN heavy crude that we produce at our Sunrise thermal production. The Superior refinery, which is currently offline, has an



operating capacity of 45,000 barrels per day. The temporary closure of the Superior refinery is a serious setback, but we'll use the insurance proceeds to rebuild. Superior is a good refinery and its acquisition last year was a good fit with our strategy. It allows us to match more closely our heavy oil processing capacity with our heavy oil production. In addition, Superior gives us added optionality around our Corridor business, as its location is the first U.S. refinery on the Enbridge Mainline. We market our own products from all three of the refineries in the U.S. Midwest, as well as a full slate of secondary products, like LPG and coke and sulfur, on behalf of the Toledo joint venture.

Turning to pipelines and storage, we have more than six million barrels of crude oil storage at Lloydminster, Hardesty, Superior and Patoka, and we have a 75,000 barrels per day capacity commitment on the Keystone Pipeline, as well as operating our own Midstream Partnership assets.

Finally, our retail business here continues to contribute value. We have more than 550 dealer operated retail locations in Canada, and we have now fully implemented our agreement with Imperial, creating a coast-to-coast truck transport network of approximately 160 travel centres and cardlock facilities. This has expanded our network and customer options, and it has doubled our cardlock diesel volumes.

So, looking forward, one of our biggest priorities is making sure that we continue to provide a home for the Company's Upstream production as it grows. This mitigates the impact of location and quality differentials. Here, we show how we plan to stay in line with the expected growth in heavy oil production. The left chart is our expected daily volume of heavy oil blend over the next five years, and the blend is the volume of heavy oil production plus the diluent that's required to be blended with it. On the right is our heavy oil processing capacity plus the long-term committed capacity on the Keystone pipeline, transporting oil from Canadian to U.S. markets. As you can see, our current configuration covers us until about 2020, with the largest change in heavy oil processing capacity coming in 2019 with the Lima Crude Oil Flexibility Project. That will increase Lima's heavy oil processing capacity from about 10,000 barrels a day up to 40,000 barrels a day. This is truly a flexibility investment, so I should mention that when market conditions are favourable to run Lima with the heavy crude slate, we'll use a portion of Keystone capacity to move heavy oil directly to the refineries from Canada, but when conditions are favourable to run light crude, we can do so. So, it makes Lima truly a flexible refinery.

Andrew still has plans to keep growing the heavy crude production beyond 2020, so beyond 2020, we also have options to accommodate these increasing blend volumes, and this includes access to the U.S. or global markets by future export pipelines or a potential expansion of our Lloydminster asphalt plant. It's a diversified strategy and we're set up so we have time to make a decision on the right way forward.

So, I think you can see that the Downstream backstop that I talked about earlier is quite secure, but true integration value is more than just about a backstop. Running a Downstream business to its full potential is also about preserving and creating optionality in the value chain. Now, this diagram is a bit complex, but so is our suite of options as we move our equity barrels from production in the Upstream through our refining and upgrading assets in Canada, through our logistics assets to refining in the U.S., and then markets either in the U.S. or Canada. The view shows where we have optionality.

For example, the heavy crude that we produce, we can either feed this to our own upgrading facilities in Canada or we can sell to Canadian markets, or we can transport to the U.S. to process in our U.S. refineries, or we can sell into U.S. markets, or if the time trade is attractive, we can store barrels in our storage assets either in the U.S. or the Canadian side of the border. All of the same options that exist for heavy oil, we also have for light oil or for syn-crude, U.S. versus Canada, market versus process, store versus sell.

Husky is quite unique in how the assets that we have are, for the most part, physically connected, not just theoretically or virtually connected, and this gives us much more optionality than your typical independent refiner.

So far, we've only talked about the crude side of the business. There's also significant optionality around the marketing of our finished products, and we've been actively expanding the markets that are available to us. In asphalt, for example, we've not only gained market share with the purchase of the Superior refinery, we also can optimize how we sell the product. For example, once we're operational again, we can serve our customers in Eastern Canada out of the Superior refinery, rather than transporting products all the way across the continent from Lloydminster. We expect logistics savings alone are going to run into the millions of dollars.

We've also gained new customers in well-established marketing terminals, which allow us to compete better on price and deliver returns.

Another new thing we started over the last year or so is we're now lifting and marketing all of our own share of the products from the Toledo joint venture, and you can see the increase in volume here. By combining the products we market across the entire U.S. business, managed out of our single marketing office in Columbus, Ohio, we can better fill large orders and we can better compete, and we're well connected with Chicago, New York Harbor and Gulf Coast markets, which allows us to optimize between the three markets.

Next, I'd like to discuss three bigger picture industry themes that we see playing out over the next several years which shape our thinking in regards to strategy in the Downstream.

The first theme, which is on everybody's mind these days, is export pipeline and uncertainty. Continued delays on all three remaining proposed pipelines are causing persistent discounting of Canadian heavy barrels, and as crude by rail starts to play a more active role, we would expect this location differential to trade at the marginal economics of rail until we get pipeline relief, probably in the '20 or '21 timeframe, the marginal economics of rail being in the order of \$18 per barrel. Because of this uncertainty, it is becoming increasingly valuable to have existing refining options in Canada or dedicated pipeline access to the U.S. where you can receive better pricing.

Now, our sensitivity to this differential is largely mitigated through a couple of factors, our Canadian Downstream assets at Lloydminster and our 75,000 barrels per day dedicated capacity on the Keystone pipeline, and Keystone, as a heavy or light pipeline, is particularly versatile in this respect, because when the heavy location differentials are wide, we can use our Keystone capacity to move our heavy barrels in Canada to the U.S., or when the heavy diffs are narrow, we can also instead use the pipeline to ship our light crude or syn-crude to the U.S. and maximize value that way. Finally, having large refining and storage capacity in the U.S. and Canada allows us to be less affected by apportionments on pipelines that are subject to apportionment. In the first quarter of this year, when the pipelines were highly constrained, we didn't need to rail or truck our crude oil at all. Looking further out, we've committed to space on both the Keystone XL and the Trans Mountain expansion pipelines, and we're in a good position

to nominate on Line 3. This diversified approach should position us from whichever pipeline happens to come first.

A second theme is the new IMO fuel standard which will require ships to make the switch from using bunker fuel to low-sulfur fuel oil. Now, this should cause increased diesel demand at the expense of bunker fuel. There's varying estimates as to the extent of the demand increase for diesel, which will depend partly on the rate of adoption of different technology options by the shippers, but I've seen demand increase estimates in the range of 2 million barrels per day, like this one, which would significantly affect the global supply and demand balance. An additional impact might be a reduction in heavy crude oil demand, as less is required as feedstock to make bunker fuel. Those most vulnerable to this change are going to be refiners with a large yield of heavy fuel oil products and those most likely to benefit will be those refiners with heavy crude and also those with a high middle distillate yield.

We expect our refineries to be net beneficiaries of the rule, and this is because we produce only a small quantity of marine fuel at the Prince George refinery and Superior and none at the other refineries. On the other hand, our refineries, and in particular Lima and Superior, produce a relatively high fraction of diesel fuel—diesel is the green bar on this chart, Prince George is here, Lima is here—and also the upgrader produces a fraction of diesel and no gasoline at all, and also since Husky is less exposed to widening crude differentials, like we discussed earlier.

The last theme I'd like to discuss is the light oil production outlook in North America. The growth of Permian production is causing a surge in the supply of light crude oil. The U.S. refining complex is limited in its ability to process all of this additional volume, with substantial capacity geared towards refining heavier crude grades. Furthermore, as this extra production is concentrated in one location, we're starting to see infrastructure constraints in getting the increased production volumes to the market. This has the effect of putting pressure on prices for domestic light crude grades in general and specifically down in the Midland Texas area. You can see the Lima refinery is well positioned to benefit, as it can run large quantities of light crude oil and it has direct pipeline access to Midland. In fact, about half of Lima's crude oil (inaudible 97:24) comes exactly that way, which is one of the shortest routes from the Permian to Midwest refining. We see this development as transitory rather than structural, pipelines will be built to allow infrastructure to catch up, but we're well positioned to benefit from it while it lasts, and

that's a big part of Downstream oil, having the optionality to act in the most profitable way when the opportunity presents.

So, to wrap it up, Downstream is a key cog in an integrated system that's designed to complement our Upstream heavy oil production and mitigate the impact of changing differentials. With about 400,000 barrels a day of throughput capacity, about three-quarters of which is in the U.S., it's a relatively large business and it competes well with others in this space. We have plenty of choices to optimize the value that we capture across the value chain. We're well positioned to capture the benefit from some of the larger macro trends that we see on the horizon, and we've been expanding the markets that we have for our finished products. The summation of these factors is a Downstream business that we expect to contribute, on average, \$1.5 billion of free cash flow annually to the group over the coming five years.

Thanks very much for your attention. Now, we'll move to the upper part of the Corridor and Andrew and Carmen will take us through the Heavy Oil and Oil Sands business.

**ANDREW DAHLIN:**

Thanks, Jeff. It's good to be back in Toronto. In this last year, since I first presented at Investor Day, I've had the opportunity and the pleasure to meet a number of you in our one-on-ones. Since that time, we've also combined our Heavy Oil and Oil Sands businesses. It's a good decision. There are material synergies to be realized, including in the application of technology, in operating excellence and in the shared culture of project execution. Personally, it's really quite exciting to be leading up a business that produces 170,000 barrels per day, more than half of Husky's overall production, and we plan to take this even higher, to around 240,000 barrels a day by the end of 2022. As Rob mentioned earlier, we're advancing this growth hand-in-hand with a redoubled focus on safety.

Our production is from three core areas. First, Lloydminster. We have an unsurpassed land and infrastructure position in Lloyd, where we're building on our legacy heavy oil business by adding a series of modular 10,000 barrel per day thermal developments. Our 10 existing thermal projects are producing about 75,000 barrels per day and we have 60,000 barrels per day of new capacity under development. The first, Rush Lake 2, is coming on-stream later this year, and the next five will be brought online in a sequenced manner through to 2021. Second, Cold Lake is the home to our Tucker SAGD Oil Sands project. We recently brought a new pad on-stream

and, as it ramps up, production will reach the plant's capacity of 30,000 barrels per day. Finally, at Fort McMurray, we have a large high-quality lease with our Sunrise SAGD project. We're currently producing just over 50,000 barrels per day growth and we remain on track to reach our target of 60,000 barrels per day around the end of this year.

Combined, our total heavy oil production from these three areas is set to grow by more than 40% over the next five years to about 240,000 barrels per day. Remember, all of this production is physically connected by our own gathering systems to our Downstream heavy oil processing facilities in Canada and the U.S., and that largely protects us from location and quality differentials. This is a very good business and we're making it better.

This slide shows how we compare with our thermal peers on three metrics, SORs, operating costs and netbacks.

In terms of SOR, which is on the left-hand side of the chart, we have five projects in the top 10 in the industry, and this contributes to our lower than average rates. Our legacy Pikes Peak development is among the taller pillars on this chart, but I'd just like to note the field has been on-stream since 1971. It started life as a conventional play and we kept deploying new technology in the exploitation of this field, ultimately converting part of the field to SAGD in 2004. We've recovered 63% of the oil in place, with a recovery factor exceeding 80% in the SAGD areas. All together, this field has generated \$2 billion in revenue over its lifespan. So, this has been a very good development for us, but as you can see, the field is now approaching its end of life. To the left of Pikes Peak are Tucker and Sunrise. We're continuing to ramp up production at both. In terms of SORs, we expect Tucker to settle around 3.5 and Sunrise to hit its design capacity of 3, which it has already done in the initial development area. Now, in comparison, our newest Lloyd thermals, have SORs between 2 and 3.

In regards to operating costs, we're amongst the better projects, as you can see on the top right. Our Lloyd thermals and Tucker have operating costs around \$10 per barrel, and we have plans in place to drive Sunrise to the low teens in the next year or two and to \$10 per barrel inside of five years. A reminder that Lloydminster crude is of a higher quality, is closer to market, and it commands a higher realized price. So, combined with our lower operating costs, we realize some of the highest netbacks across our industry.

We continue to develop and add to a deep inventory of projects across our thermal portfolio. At Lloyd, we have 60,000 barrels per day of new projects under development. These projects are set to come on-stream between the end of this year and 2021. Beyond these six projects currently underway, we have another six projects that are ready or being readied for sanction. The plan is to sanction an average of two per year for the foreseeable future and these projects will come on production starting in 2022, and, as I'll show you later, we continue to find tuck-in land acquisitions that allow us to expand and/or improve our current inventory.

At Tucker, we're making steady progress. We brought on a new 15-well pad earlier this year and production will ramp up through the year. We're also executing a turnaround in September, during which we'll debottleneck both the field and the plant. This combination of new wells and debottlenecking will help us reach a 30,000 barrel per day design capacity around the end of this year. Looking ahead a few years, we'll keep production broadly flat at the plant's capacity, with future sustaining pads targeting both the Clearwater and the Grand Rapids formation. This gives the project a remaining life of about 25 years. With the plant running full and with operating costs around \$10 per barrel, we expect this asset alone to generate upwards of \$600 million in free cash flow over the next five years.

At Sunrise, we've averaged around 50,000 barrels per day in the quarter to date and remain on track to reach the 60 mark towards the end of this year. Once fully ramped up, our focus will be on plant debottlenecking opportunities and subsurface optimizations. Looking even further out, we'll be adding additional phases at Sunrise.

So, for the remainder of the presentation, I'll zoom in our Lloyd thermals, after which Carmen will focus on Sunrise.

On the right, for our Lloyd thermals, you can see the production profile for existing projects. We started our cyclic steam stimulation program in the Lloyd area about three decades ago, and over the past 20 years or so, we've focused on SAGD. Overall, in the last three years, we've doubled our thermal production by adding four projects and close to 40,000 barrels per day of thermal production to our legacy position, with our year-to-date production averaging about 75,000 barrels per day, including some smaller turnarounds here in Q2.

On the left, you can see the proximity of our thermal assets to the Lloyd complex in the centre and the associated gathering lines. All of our current production is physically connected to our Lloyd and Hardisty assets by our Midstream Partnership, and as Jeff just referenced, we leverage this physical connectivity, and the optionality within, to increase the value of every barrel we produce.

We also find ways to improve the economics of our thermal production. Our Lloyd projects use the same team, the same design, and even the same electricians and welders, who go from site to site. This consistency in process and execution has led to more sustainable, lower cost production. For example, we expect Rush Lake 2 to come in between \$25,000 and \$30,000 per flowing barrel, and that's for a greenfield project. Once operational, the project will have low operating costs and low sustaining capital requirements of about \$6 per barrel. In terms of operating costs, and as you can see, our average barrel of costs for all our thermal production has come down by 40% from 2015, and by the end of the plan, our low-cost thermals will represent about half of Husky's production base, which will help bring down our overall operating costs in the Company.

So, looking ahead, we'll offset the natural decline and the shut-in of our older facilities with a wave of new strong thermal developments. We're currently active on six projects, shown on the left here as red stars, which means we're advancing an additional 60,000 barrels per day of new Lloyd thermal nameplate capacity. We'll start producing at Rush Lake 2 later this year, with a design capacity of 10,000 barrels per day. Following that, the trio of Dee Valley, Spruce Lake Central and Spruce Lake North will come on in 2020, representing an additional 30,000 barrels per day of capacity, and then the most recently sanctioned projects at Edam Central and Westhazel will add a combined 20,000 barrels per day of capacity when they start up in the second half of 2021. Beyond this, we plan to bring on an average of two new Lloyd thermal projects, or 20,000 barrels per day in capacity, every year, using the same modular cut-and-paste design, and I'll talk more to this future in a couple of slides from now. Now, as the map on the left shows, the expansion, the Midstream will be adding pipeline capacity for all our planned new production, and in doing so, we retain that tight integration with our Downstream business.

So, I'll pause now for a moment and give you a quick look at the progress we're making on Rush Lake 2. It's important to understand that our thermals are near-carbon copies of each other. You'll see this same layout and the same equipment at all our new Lloyd facilities. So as



to give you a tangible feel, I want to show you a video from Rush Lake 2. What you can see here is our central processing facility and one of our well pads in the background. Steam is generated at the OTSGs, brought out to the well sites, heats up the reservoir, this pump brings the emulsion back to surface, pumps it to the CPF, where this emulsion is treated in these vessels here, and then that oil, that clean oil, is then shipped through our own infrastructure all the way to our Lloyd complex. Now, what you're seeing here is really our standard setup. After Rush Lake 2, our next project is Dee Valley, where construction is underway and modules and vessels are arriving at site, and at Spruce Lake, site prep is ongoing, with the same vessels and modules in fabrication.

So, I really hope you've enjoyed this video. As a takeaway, think of this as a manufacturing business. We use the same design, the same building blocks, and with a continuous improvement in our already strong track record of efficient execution. By the way, that was shot with a drone.

Finally, I mentioned earlier that we have a strong land position in Lloyd and that we have big future growth opportunities beyond those six projects on the go. No question we are the biggest player in this area. In fact, as described earlier by Rob Peabody, we have our own moat. We hold mineral rights to every other section of a large two million acre parcel, we operate all the gathering lines, and right in the middle of the block is our own Lloyd refining complex, specifically configured to maximize the value from our type of crude. We've been actively filling in this checkerboard of land to further develop our project inventory. At the same time, we've been working to optimize our footprint by taking a clustering approach. This means we're strategically acquiring land positions that allow us to build multiple projects in close proximity. The benefits are clear. For each project, we need a water line, a condensate line and an emulsion line. When these projects are clustered within the same area, we remove the duplication of this infrastructure and we realize good cost savings. Grouping projects in the same tight geographic area also means we can build them in sequence, providing for lower drilling costs and the sharing and optimization of construction services.

Here, you can see examples of a couple of recently completed deals, either through land swaps or acquisition. The light brown outline that you can see here in the centre shows the Waseca geological trend, on which we have two existing thermals on production. At Spruce Lake, in the north, a recent land acquisition has provided for an additional 10,000 barrel per day project, on

top of our existing inventory of 25,000 barrels per day, and at Dee Valley, in the south, we've topped up with two additional projects and upsized another, creating a hub representing 40,000 barrels per day of thermal potential. It's these types of opportunities that we're progressing to sanction-ready projects in the near term, and as you can imagine, they further strengthen our overall thermal portfolio.

So, that wraps up the Lloyd section. I now would like to ask Carmen, our Vice President of Oil Sands, to give us an update on Sunrise. Thank you.

**Carmen Lee:**

Thanks, Andrew. This is my first Investor Day, so I am looking forward to meeting many of you after the event to answer any additional questions. I'd like to start off by saying that I'm really glad to be back in Oil Sands. My last operational assignment was with Tucker Lake, where we brought an 1,800 barrel a day project to past 20,000 barrels a day, and I was actually rewarded for that effort, but with a role in Corporate Planning. So, I am really keen to be back on the operational side again, with Andrew, and with the job of taking Sunrise to full capacity and beyond.

As stated earlier, our ramp-up at Sunrise is proceeding. We hit the 50,000 barrel a day mark back in March and we remain on track to reach our target of 60,000 barrels per day around the end of this year, which is 30,000 barrels per day net to Husky. Our leases are located in the heart of the oil sands fairway, with Suncor's Firebag just to the east of us. Sunrise has 1.9 billion barrels of 2P reserves growth booked as of year end 2017, with approvals in place for 200,000 barrels per day, so we have a long production life ahead of us.

So, let's talk about what we're seeing in the subsurface. We set a target of between 800 to 900 barrels per day for the original 55 well pads from the initial development area. This slide represents the data for March, when we were averaging about 815 barrels per day. Following some recompletion works on a few wells in the first quarter, we have seen the upward momentum begin again, with an average rate per well today of just under 830. Daily production rates do bounce around a bit, but we expect this to settle in around the middle of our range. The green bar on the left indicates the average well pair production from the IDA wells, and it shows that we're amongst the best, close to Firebag and Christina Lake. The second green bar represents all of the wells, including the second development area which is still ramping up. Our

initial development wells rank within the top-quartile producers and we believe the second development area has the potential to do the same.

We're using a number of techniques to improve the resource recovery at Sunrise. As you can see on this chart, we're seeing a faster ramp-up profile in the latest wells, and you can see this here in the dark green line. Some of you might wonder why this trend appears to be flattening out. Well, we're doing some operational things up at site, such as steam optimization, which is contributing to this; however, we expect the upward trend to continue. The SOR has improved and is approaching 3 for the IDA wells and we expect the rest will reach the same point. I'll remind you that we had a negative hit to our SOR in the early stages as a result of the wildfires in Fort McMurray. We've recovered, but it certainly affected our original timing for ramp-up.

So, what are we doing differently with these wells? In the initial development area, we have drilled infill wells. The number one reason we are doing this is to reduce SORs by helping to recover the resource in between the steam chambers. These infill wells can be used as a low-cost alternative to new pads. To date, we've drilled 12 infill wells. The first one has come on and the rest will follow over the balance of the year. We've also been actively working to improve our performance in the least productive wells. We've been addressing this by bringing these wells up higher into the pay zone. This technique, which is also known as a flip, because the old injection well becomes a producer, has helped us increase the production from these wells by an average of 225%. We've completed our program of six flip well conversions, with no more planned. In the second development area, we are using electrical submersible pumps out of the gate, instead of gas lifts. We also have installed tailpipes or inflow control devices. These help optimize production by equalizing reservoir inflow along the horizontal section of the producer.

As we plan to increase the production from Sunrise, we need to make some room at the plant. We've actually done some of this groundwork already by re-rating the steam generators to increase their capacity by 10%, or another 6,000 barrels per day of gross production. Beyond this, we have one more bottleneck planned that should carve out an additional 12,000 barrels per day of growth capacity. This growth will be achieved through the planned installation of a co-generation facility. In terms of future phases, regulatory approvals are in place for another 140,000 barrels per day, so we have lots of room for future development.

As you can see in the map on the right, our future development is adjacent to Firebag to the east, Kearl to the north, and the new Aspen project to the south. However, we recognize more work has to be done to get the next phase to meet our internal hurdle rate of 10% rate of return at US\$45 WTI. We're taking several approaches to accomplish this. First, building on our expertise with Lloyd thermals, our future phases at Sunrise will be based on a more modular, bite-sized approach, with 20,000 barrels per day design capacities. Second, recent advances in proven emerging technologies are expected to reduce the size of the plot plan for a central processing facility by half. Finally, we're examining future technologies, such as our Husky Diluent Reduction Initiative. This involves heating synthetic crude oil and mixing it with bitumen to create a pipeline-ready stable crude blend. We have started construction on a 500 barrel per day pilot program at Sunrise, and while this technology is still in its early stages, we anticipate it has the potential to reduce our condensate diluent requirements by 50%.

On behalf of Andrew and myself, I'll wrap up by noting that our thermal business is the main growth engine for Husky over our current plan. We are adding about 80,000 barrels per day of new longer life thermal production. This growth remains self-funding under our US\$60 WTI and WTI/WCS differentials of US\$18 per barrel. While it's one of the largest areas funded by our capital program, it is also helping to lower our overall cost structure and sustaining capital requirements, and with the help of new technologies and future application of repeatable modular design, we will continue to tap more deeply into our vast resource base.

With that, thanks very much. I'll now turn the mic over to Gerald to talk about our Resource Play business in Western Canada.

**GERALD ALEXANDER:**

Thanks, Carmen. Those of you who were here with us last year may recall at that time we were in the final stages of repositioning the Western Canada business towards fewer, more material resource plays. The process is now complete and we are now beginning to realize the benefits of having a more focused investment portfolio which can operate as a competitive standalone business. I'm really excited to be part of this return to growth, and I'll tell you why. I've been in this business for more than 20 years and I can tell you that these past two years have been nothing short of transformational. We've sold about 52,000 boes per day since the program began in late 2015. These were largely legacy assets with higher operating costs, meaning it was difficult to make an economic case for further investment under our current hurdle rates.

Earlier this morning, Rob Peabody talked about a shrink-to-grow strategy, and I'm happy to say that in the Western Canada business the shrinking part is now over. Today, we are focused on three core hubs, in Edson, Grande Prairie and Rainbow Lake. We hold material land positions with a lot of room to run, including greater flexibility to pivot between liquids-rich or dry gas, depending on which provides the better economics. We also have built-in pipeline access to U.S. markets, which Rob has already touched on. This means we can realize a substantial premium to AECO pricing. Our increased focus is creating a number of efficiencies, resulting in steadily declining operating costs, faster drilling times and better individual well performance, and with just three core hubs, we are seeing a marked improvement on our overall safety performance. I'll just note that by simplifying our business and focusing our efforts, we haven't had a safety incident in more than seven months, and that's a new record for the Western Canada business.

I spoke about the transformation of our Western Canada portfolio and the next couple of slides shows you just how dramatic the change has been. At the end of 2015, our operations covered a wide swath of the basin, from northeast B.C. through much of Alberta and into southeastern Saskatchewan. This large footprint meant there were a number of built-in inefficiencies. It required a lot of people to operate, operating costs were relatively high at about \$16.50 a boe at the end of 2015, and the average production per active well was pretty underwhelming at about 8.5 boes per day. Our average working interest per well was about 60% and we managed about 31,000 gross wellbores. This old model required a lot of capital every year to essentially keep the production flat, so this change made sense, and it has been driven, in part, by the structural changes of the Canadian natural gas markets and in the range of new technologies that are available. As you've heard from Rob Symonds, we are using technology to get better results, and we're also focusing on plays with better reservoirs.

Let's look at the Western Canada business today, and what you now see is a much more focused, centralized set of operations. As I mentioned earlier, we are concentrating our activities around hubs at Edson, Grande Prairie and Rainbow Lake. Through increased efficiencies, we've been able to drive our operating costs down from \$16.50 per boe to just over \$12 per boe in the recent quarter, and we're seeing further gains on this front. Our average working interest per well has risen to 80% and our average production per active well has gone up by more than 400% to about 44 boes per day, and we have streamlined the complexity of our business.

Remember those 31,000 gross wellbores? Well, now we're down to around 6,000. Prior to 2015, we had 25 rigs running just to maintain production. Now, we're currently running about five rigs and we're delivering growth. The bottom line is that we're becoming a much more cost-effective and efficient operator. I would characterize it by saying the efficiencies gained by our leaner, focused and repeatable operations are paying off.

Now, let's take a look at how the centralized approach is working for us. Most of our current activity is in and around Edson, which is the red star on the right-hand side. We have a substantial position in the Ansell/Spirit River fairway, with about 170 net sections of land. This is a multi-zone play that is delivering some of industry's leading results. The blue star shows Grande Prairie, which is the nexus of our activities at Kakwa and Wembley. This is the area for liquids-rich gas and we have secured material land positions. The third hub is at Rainbow Lake, and you can see the green star, where we have a well-established operation. Rainbow has been a good asset for us over the years, on top of which our NGL project is providing us stable production, with more liquids upside still to be tapped. It's essentially flat production for another decade. We have significant positions in material plays and our focus on the Spirit River and Montney has allowed us to become more capital-efficient and gives us flexibility on the liquids side.

Now, let's take a more detailed look at our development in the Montney, at Wembley, and at the Spirit River and Ansell.

Wembley, which is adjacent to Pipestone, is a big part of our pivot towards more liquids. We have primarily targeted the liquids-rich Middle Montney, with NGL yields of 100 plus barrels per million cubic feet. We have been working to prove up our acreage and our results to date look promising, with one well producing and two tested and awaiting time. Our appraisal program has seven wells to be finished in 2018, and we are now moving forward and are planning a commercial development including other Montney horizons. All together, we have 50 net sections at Wembley and we'll seven wells tied in by the end of this year. We also hold a material land position at Sinclair and are in the appraisal stages. The pace of our development here is going to be matched with our egress solutions as they become available in the short, medium and long term.

At Ansell, we're building towards a full field development that will target the complete Spirit River package. We've identified about 360 Spirit River locations. In addition to the Spirit River, we will also focus on our Cardium play, which has liquid yields of 60 barrels per million cubic feet. Technology and data integration has been a big part of our improving well results at Ansell. We have leveraged our extensive 3D seismic in targeting and steering our drills, we have used data analytics and better bit selection to improve our rig performance, and we are now optimizing our well performance through enhanced completions and flow-backs, and having three working interest plants in the same area will give us increased optionality.

We are continuing to develop a track record as a top-tier, low-cost operator. Our average drill times have been reduced by more than 50% and we are now on par with the industry leaders. We've made a lot of headway in reducing our drilling costs, with our last Wilrich rig completing its operation in just 14.5 days. We've gone from average peak production rates of about 3.5 million cubic feet per day in the 2012/2013 timeframe to average peak rates of about 7.5 million cubic feet per day today. A recent report by Scotia showed that out of the top 20 new gas wells in Alberta for Q1, we had the number one spot at 19.5 million cubic feet per day, as well as another three in the top 10. At the same time, we're exploiting technology advancements to capitalize on our ability to conduct higher intensity fracs, and we're really just getting started there.

Let's now take a look at how we're developing infrastructure to support our growth. I mentioned earlier that we will have three gas plants in the same area, one of them a new build at Corser. Since infrastructure constraints currently limit the pace of our growth at Ansell, we are building this new processing plant through our Husky Midstream Limited Partnership. Construction is underway in the plant, which is scheduled to come on-stream by the end of 2019. This is the first venture of its kind through our new Midstream Partnership. The plant uses an industry-proven eighth-generation design and will optimize our field production to get the most value. The bottom line here is that we expect Corser to reduce our third-party processing fees by about 30% on some of our production.

Another key to our competitiveness is our effective marketing strategy which has allowed us to capture pricing substantially higher than AECO. We have long-term secured pipeline access to U.S. markets on the northern border and on the Gas Transmission Northwest Pipeline. The incremental benefit of this pipeline is captured in our Infrastructure and Marketing segment. Our

U.S. export capacity represents 60% of our gas production, and in Q1 of this year, these volumes received pricing that was 90% higher than AECO, at about \$3.50 per mcf. Another built-in advantage is that we are a large consumer of natural gas at our Heavy Oil and Oil Sands operations, and we're able to capitalize on the current low AECO rates to purchase gas on the market to meet our growing needs. Also, 30% of our production is liquids, and as we move forward in our plan, we'll continue to focus on zones and assets that have higher liquids to further reduce our AECO exposure.

When you put it all together, our Western Canada resource play business is well positioned with springboards of growth opportunity. The nature of this portfolio, with its short cycle capital spend profile, means we can quickly adjust to changing price environments with product flexibility. Meanwhile, our marketing strategy has minimized our exposure to weak AECO pricing, while our arrangement with Husky Midstream will reduce our operating costs and secure market egress.

Thanks very much. I'll now turn it over to our Offshore business in the Atlantic and Asia-Pacific regions, starting with an overview from Trevor.

**TREVOR PRITCHARD:**

Thanks, Gerald, and good morning, everyone. I moved back to the Atlantic a few months ago and I'm now leading a team that I used to work with when we were first preparing the SeaRose for operations back in 2005. So, even though I've spent the last few years in Calgary as the VP of Process and Occupational Safety, I guess the salt stayed in my blood and I really enjoy getting back to the Atlantic region and be part of that team again.

Our Offshore business is comprised of development and exploration opportunities in two regions. In the Atlantic, we are building on more than 30 years of experience in the offshore Newfoundland and Labrador. We are continuing to roll out a series of development wells in the Jeanne d'Arc Basin, which will help mitigate the declines until our next phase of growth kicks in when the West White Rose starts up in the 2022 timeframe. In the Asia-Pacific, we are growing our high netback gas business in China and in Indonesia. We're exploring new prospects in the South China Sea, and as you saw last week, we have a new shallow water discovery that we are evaluating.



Both of our Offshore businesses have made strong free cash flow contributions over many years, with Brent-like pricing. And in both areas, we have the advantage of expanding our business using existing infrastructure, whether it be our own vessels, such as the SeaRose and the subsea infrastructure, or the platform and the pipelines and the gas plant at Liwan. This helps us achieve lower capital and operating costs for new production. In addition, we have been actively exploring in both regions and recently have announced two new discoveries in Asia-Pacific and the Atlantic that we are now evaluating for potential commercial development. But, most importantly, our ongoing focus in both regions is to deliver our current and future production safely and reliably. Both Bob Hinkel, myself and our respective teams are committed to continuous improvement on that front.

Now, I'll start the Offshore segment with a closer look at the Atlantic region, after which Bob will provide an overview of our Asia-Pacific business.

This region continues to deliver some of the best returns in the portfolio and we've made considerable progress over the past year. It's certainly been a solid investment. Since we started in 2005, we have delivered over 280 million barrels of oil, or 200 million barrels net to Husky. This is a premium quality mid-distillate type of crude. We've harvested the original White Rose development, which is now in gradual decline, and with the investments we are making in West White Rose, we are poised to rejuvenate the production from the region once again.

We are continuing to progress a subsea program to offset reservoir declines through infill drilling and workover operations in the main White Rose field. Overall, we are expecting to bring online an average of two infill wells or workover opportunities per year. While these infill wells have historically been very good performers for us, the latest one at North Amethyst had some challenges with some high water cut. That well is currently shut-in and we are developing a remediation plan for that particular well. We continue to advance this program with an eye to mitigating production declines until the start of the West White Rose project in the 2022 timeframe. Once online, West White Rose will contribute in no small way to our growth, peaking around 52,500 barrels a day net to Husky by 2025.

At this time last year, we had just announced the sanction of West White Rose. The economics of that project made a very solid case for us to proceed. One of the unique features of this project is that we'll utilize the SeaRose processing capacity, which will help maximize the

efficiencies and resource recovery. This means that we have a low incremental operating cost over the first 10 years of life. This will drive down the overall Atlantic region per barrel operating costs. The capital expenditure on West White Rose are already resulting in lower royalty rates for our existing production.

We've been making good progress over the past year at our three active construction sites in Newfoundland and Texas. Construction of the fixed wellhead platform is proceeding on schedule at the purpose-built graving dock at Argentia, Newfoundland. Test bores have already been completed and we will start pouring the base slab in June, with the slip forming, building the structure on the concrete gravity-based structure in September. The topsides, which chiefly consist of a drilling unit, is being prepared in Ingleside in Houston, the first steel there was cut in April, and the living quarters being built in Marystown, Newfoundland are now taking shape.

Meanwhile, the next chapter of our growth in the Atlantic region is now being written. A series of discoveries in satellite developments in the White Rose production area has improved the longevity of the original field.

As you saw in our recent news release, the latest discovery, being the White Rose A-24 exploration well, and that's located approximately 10 kilometres north of the SeaRose. The well was drilled this past quarter and has encountered more than 85 metres of oil-bearing sandstone. It's still being assessed, with further evaluation planned into next year. Any potential development, of course, could tie back directly to the SeaRose and use the current infrastructure.

We also picked a parcel of land last year in the Jeanne d'Arc Basin that is adjacent to our other exploration licences. The parcel, which you see in yellow here, covers an area of about 120,000 hectares and expands our running room in the region. We'll evaluate the timing of exploration in the context of our full suite of activities.

In the Flemish Pass, we hold interest in five discoveries, including Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen. We continue to evaluate the commercial potential to these discoveries with our partner.

All told, we have a lot of opportunities on our plate, above and beyond the projects already in development. It's a really exciting time in the Atlantic region, it's a great place to be and I'm pleased to be back there.

So, that's the information on the Atlantic region. I'd like to ask Bob Hinkel now to come up and give us the overview of the Asia-Pacific region.

**BOB HINKEL:**

Thank you, Trevor. We made considerable progress over the past year. I'd like to speak to how operating in this part of the world continues to benefit Husky's bottom line. As Rob mentioned earlier, we're right at the doorstep of a very fast-growing energy market. We have built a considerable track record in this region for executing large projects on time and within budget. This includes Liwan, which was brought online just seven years after discovery, and is considered to be one of the fastest developments in the world for such a large deepwater gas project.

Our production offshore China and Indonesia is delivering high netbacks due to gas sales contracts with attractive terms, combined with low operating costs. With major infrastructure investments at Liwan and BD behind us, we can add new production in those areas at lower cost. These projects and potential growth opportunities share some important traits: first, once online, they generate high returns; second, they share existing infrastructure, including subsea pipelines and onshore facilities; and third, because of this, there's relatively little incremental capital needed to bring on new production, we can plug into what's already there. We also have exploration opportunities, including a significant recent discovery, which I'll speak to in the next few slides.

The macro dynamics in Asia continue to be very attractive. China and the Asia-Pac region are expected to be amongst the largest energy-demand growth regions in the world for the next couple of decades, and we plan to grow right alongside. In China, we are bringing on the third field in our Liwan development, and in Indonesia, we're rolling out a series of projects in the Madura Strait on the heels of our liquids-rich BD field. An important factor in all this is the nature of our production. Cleaner-burning natural gas is the ideal fuel source for electricity generation and other industrial uses in China, helping the country to continue to improve its air quality, and in Indonesia, economic and industrial development, combined with aging and competing gas

fields, should allow Husky to become a material and long-term provider of energy to customers across East Java.

We now have more than 400 million cubic feet per day of gas production being sold under long-term contracts in China and Indonesia. Our overall realized price for gas and liquids production for the first quarter of this year was about CAD\$80 per boe. For our Liwan production, we have gas sales contracts for existing P1 reserves at favourable prices. The prices in these contracts also have escalators which will vary over time within bands. As a result, we expect that price and our production volumes to continue to be both attractive and stable over time. In Indonesia, we have three gas buyers with sales contracts for our BD project. Demand from these buyers is steadily ramping up and is currently at about 80 million cubic feet per day, headed towards project capacity of 100 million cubic feet per day. Gas sales contracts are largely in place with the MDA-MBH development, which we anticipate to bring into production toward the end of 2019. We're also continuing to see higher liquids yields than we expected in our plan, in both China and Indonesia, and we can sell this production at Brent-like market prices.

With a stable business in China and Indonesia as a foundation, we're pursuing production growth in both regions and we expect to grow more than 30% over the next five years or so. As with our current production, we expect our future projects to be efficiently developed, from a capital perspective, and to generate profitable high netback production. So, let me describe some of the opportunities we are currently pursuing.

First, I'll start with the Lihua 29-1 field at Liwan, which we've already started development on. We sanctioned this project last year and signed a gas sales agreement. More recently, we upped our stake to 75% from 49%. This puts our net share of production in this field up to 45 million cubic feet per day of gas, and 1,800 barrels per day of liquids, once fully ramped up. This new field, which is the third in the Liwan trio, will tie back to existing deep water and shallow water infrastructure, thus reducing development costs and time. Our plan calls for us to drill three additional wells at 29-1, which is scheduled for the fourth quarter this year. First gas is expected around the end of 2020, which we'll process at the Gaolan gas plant for delivery to specified power plants who are buyers in local areas. Once we're up and running, we expect to recover approximately \$250 million in exploration costs, on a preferred basis, over the first 18 months of production. Production ramps up quickly because the gas supply is dedicated to

specific end users in this case. Once on production, this project will contribute more than \$100 million in free cash flow per year.

Turning to Indonesia, we hold a 40% interest in a Madura Straight production sharing contract. At the first development, which is the liquids-rich BD field, gas sales began last July, with the first lifting of liquids in mid-October. We're using a fixed wellhead platform and FPSO, with the processed gas transported through a dedicated pipeline system. Production is continuing to ramp up, with gas sold to local buyers in the East Java market currently at 83 million cubic feet per day, gross. There's a substantial amount of liquids in this gas, about 6,000 barrels per day. These liquids are sold to petrochemical facilities in Singapore at Brent-like pricing.

Next up, at the combined MDA-MBH fields, seven wells will be drilled in the second half of this year and first gas production and sales are expected around the end of 2019. Another field at MDK will be tied into this infrastructure in the 2020 timeframe. All these fields will share that infrastructure, including a floating production vessel, and the processed gas will be tied directly into the existing East Java subsea pipeline system. Following that, a plan of development is in place for the MAC field and feed activities are also continuing, and we have three additional discoveries that are being evaluated for potential development in the future.

We continue to have an active exploration and appraisal program underway in the South China Sea. To start with, Husky has signed for new PSCs in the last two years, and we've just made an oil discovery on the first well at Block 15/33 offshore China. The well tested at a combined production rate of over 9,000 barrels per day with no water cut. We are now preparing to drill a second well on the second structure in this block. After this, we'll move to nearby Block 16/25 to drill two more exploration wells later this year. We also have two additional shallow water blocks to test in the proven Biebuwan Basin near Hainan Island.

So, we have several advantages in these blocks. They're located near a high-demand market and, second, these blocks are all in shallow water. You can see here there are several FPSOs already working the area; meaning, that all we'll need in terms of infrastructure is a shallow water platform and some wells to be drilled to bring these on production. Longer term, we've wrapped up a major 3D seismic program on our Taiwan exploration block. We view this as being a highly prospective block in an area that's basically underexplored.

So, overall, we've got a solid record in the Asia-Pacific region. We continue to leverage our offshore expertise and have established relationships there. We expect our Asia-Pac business to continue to generate high netbacks, strong free cash flow, and capital-efficient growth opportunities for many years to come.

So, to wrap it up, when you combine both the Asia-Pac and the Atlantic businesses, the upside is quite evident. Each region is contributing high netback production. In the most recent quarter, combined operating netback was \$68.27 per boe. We're able to sell our products into regional and global markets. We have a strong track record in both regions for project execution, strong partnerships and exploration success. You can see from the chart at the top right here that we're showing growth out to 2026, reflecting the longer wavelength nature of some of these businesses. On the right, Asia appears to be peaking at 2021 and falling off. However, this doesn't assume any successful additional discoveries, as we, in fact, just announced recently. This is part of the continuous investment and harvest cycle that Rob Symonds spoke about earlier, and beyond 2022, we will once again be entering a harvest cycle as West White Rose is brought online, and we have further long-term opportunities to bring online in Asia.

Thank you very much. I'll turn the floor back over to Rob Peabody now to take your questions.

**ROB PEABODY:**

Okay. So, I'm happy to take any questions that you might have on any of that.

**MALE SPEAKER:**

Thanks. Just quickly here on potential inorganic opportunities—I know you indicated that it has to have at least financial alignment, as well as alignment in strategy—I was just curious as to what you would quantify or qualify as being kind of the alignment in the strategy going forward and what type of assets would that describe.

**ROB PEABODY:**

Yes, okay. So, essentially, in terms of the strategy, as you can see, really those businesses about the Integrated Corridor and the Offshore business, and the Offshore business is really in two jurisdictions, both of which we feel we have a strong presence in today and have a lot of advantages because of existing relationships, and a demonstrated ability to execute projects over a very long time. So, really, we're looking for projects that would reinforce both potentially

Offshore activities in those two jurisdictions and acquisitions that would reinforce the Integrated Corridor, so either in the Upstream piece of it or further Downstream.

Now, in the case of the Downstream, the way we've set ourselves up, we're essentially in good shape to be integrated until—to be fully integrated until 2021/22, and clearly our Downstream is really in service of our Upstream heavy oil and bitumen business, so that's the driver there, is our growth in the Upstream. We feel we're in a good position until then. Now, clearly, in terms of Downstream, it would be really based on a view of what is going to happen in the pipelines that are being developed. There's been some developments today. It appears the Canadian government continues to be very, very determined to get TMX built to the West Coast. We certainly are in favour of that. We believe it's really important both in terms of accessing new markets for Canada, clearly, so we don't end up in a bottleneck situation further out. So, hopefully, we'll be able to see, prior to needing to make more Downstream acquisitions—we still have the option of the Lloydminster asphalt plant at some time in the future—whether or not that's the best place to look to spend money there.

But, that being said, I do want to just bring back what we always raise, the prospect of acquisitions, so we don't surprise anybody if we did one that's on strategy and, I would emphasize, within our financial framework, so that we aren't going to put the balance sheet at risk or our investment grade credit rating at risk for any acquisition. We still like our base plan, so we're not aggressively out there looking for acquisitions. Things may arise that look compelling, and if they look compelling and are on strategy, we may pursue them, but our base plan, we're pretty comfortable with.

**JASON FREW:**

Hey, Rob, it's Jason Frew from Credit Suisse. I just wanted to go back to the safety initiatives that you talked about, and I ask because this is a key area of pushback in the story, I think, one of the few remaining, frankly, because you've proceeded well on some other tracks, but my question is, is this a case of Husky being behind the curve on some of these items relative to the industry or are you actually moving ahead of the industry now on some of these initiatives, given some of the incidents that you're responding to? Thanks.

**ROB PEABODY:**

Good question. Thanks, Jason. It's a difficult one, I always have to say, because safety, I always say, is one of the most difficult things to manage in an oil company. It's not a new journey for us. We started, literally, a decade ago, in putting in a comprehensive process and occupational safety system that addresses the identification of risk and the use of procedures around all our high-risk operations. The last series of events have been quite frustrating. I'd also say again—you can spend a lot of time on each one—what's interesting, as well, there wasn't really a strong common thread between them, they were quite different.

I still believe the path we've been on, the rigor we've been implementing HOIMS, what we do with audits, both our own and internal and third-party party audits of our process safety systems as they exist within the Company today, I actually think is pretty much on par with what most other oil companies have been doing. However, regardless of thinking we might be doing something right, if you're having incidents, you should be doing something more. So, as I outlined today, the additional steps we're going to take is, number one, we—well, we have already, we have always tied compensation, to some degree, to safety, we're going to make that much more explicit, both so our investors can understand the focus that we're putting on this and that all our employees also understand why it's so important even to their own compensation, raising the profile of the person in charge of process and occupational safety to a direct report to me.

But, I think the really interesting one—and to pick up on the second part of your question—something that I do believe has the potential to move us ahead of the industry, in general, is this initiative with the High Reliability Group in the U.S., who is a group I've known of for quite some time and we've actually—I've had a bit of a relationship with the fellow that runs it for a while. As I say, what I think is very innovative about this is it is really taking the practices that they use kind of at the sharp end of running the U.S. nuclear navy and saying how do you actually adapt that and put it into oil field operations and demand for refining. The real key to that, at the first supervisory level across the Company, is giving people the skills they need to differentiate between normal operations and high-risk operations, and then to switch over to an extremely rigorous process of following procedures and checking that each other are following those procedures at times of high-risk operations.



So, I think what's interesting about that is, well, you could say, "Well, does this eventually overwhelm you with procedures?" In fact, what it does is it high-grades your procedures and distinguishes between these high- and low-risk situations, because, in some ways, one of the problems we have in the industry is we're almost overwhelming frontline supervisors with mountains of procedures and things that they have to follow, and regulations, and all sorts of other things. I mean, it's a very different industry than it was a decade ago. So, this allows them to filter and focus. That's actually what we're teaching them at the frontline, how to understand what's high risk, what's normal risk, when it's high risk, how to get focused and how to get onto the right procedures, and I think this is industry-leading not just in our industry, but further away. I mean, I think the High Reliability Group likes to refer to this as ultra-high reliability operations. So, we'll see where it takes us, but I'm pretty impressed with the individuals involved in this organization, and it's only a small—it's not a big consulting organization, it's basically about 12 ex-nuclear submarine commanders, plus a few admirals, sort of gotten together to say, "We think there's a way to significantly improve operations in some of these other industries."

**NICK LUPICK:**

Nick Lupick from AltaCorp Capital. I was just wondering—acknowledging that you said that it's a bit early for a timeline to get the Wisconsin facility back online, I was wondering if there's any kind of additional details you could give us, maybe which part of the facility was most badly damaged, was it human error, was it just a bad luck situation, or any kind of colour you could give us would be appreciated.

**ROB PEABODY:**

Super. Okay, Nick, I'm going to hand that over to Jeff, so he can—he's spent more time there. I have spent time there, as well, but he's spent more time there than I have in the last month.

**JEFFREY RINKER:**

Yes, the most heavily damaged unit is the FCC unit, although adjacent areas around the FCC were also affected by the fire. We just don't know what the root cause was, it's too early to tell, the investigation is going to take some time, and we're being very deliberate about it, and also, of course, we're working closely with the Chemical Safety Board, who will also be doing their investigation and making a report. As we know more, we'll share. We're really only getting in there now to assess the extent of the damage and beginning to understand what equipment

was the most affected, so too early to tell, also, about rebuild time, but the damage is extensive and we're thinking in terms of this is not going to be a quick return to operation at the refinery.

**ROB PEABODY:**

Yes, the only thing I'd add to that, in terms of people who need to model financial results, essentially, their insurance should cover all the—both the property, third-party liability and business interruption. There are some small deductibles on those policies, but they're not very large.

**MIKE DUNN:**

Hi, Mike Dunn with GMP FirstEnergy. Rob, if I just sort of compare some of the slides versus last year at this time, I think you've got some more thermal projects in your inventory here, but the nearer term, I guess, production profile looks a little bit lower than you were suggesting a year ago, I think, from the Lloyd thermals. Can you maybe just talk to whether or not that's one of the old projects rolling off?

**ROB PEABODY:**

Yes, there is one project that rolls off that causes that little blip down in the Lloyd thermal, and that's the Pikes Peak, the original Pikes Peak project, which has now, as Andrew said, has been producing since 1971. I mean, we'll see—we always have this conversation every once and a while. It depends on oil prices as to whether you actually shut it in, but it's right at the margin now, where we would actually look at shutting it in. So, you get this step-change of a couple of thousand barrels a day sort of in the production this year. I think that's the major difference.

I think the other thing, again, to be very frank, is that when we looked at the assumptions—this is a classic when Andrew took over the business. Everybody always likes to look at the all the assumptions very carefully and reset the baseline. But, when Andrew took over the business, they looked at the average throughput of a thermal project in Lloydminster. As you know, our nameplate capacity on these businesses is 10,000 barrels a day. However, none of them produced 10,000 barrels a day when they started up, they generally produce somewhere between 10,000 and 14,000 barrels a day—actually, generally between 12,000 and 13,000 barrels a day when they first started up. What Andrew noticed, when he took over the business, was that the assumption they were using for all the new thermal projects was closer to the upper range of that range of 12,000 to 14,000 for the first few years of the project, when really, if

you took the average of all the projects we had started up, it was closer to—I think it was 13,000 versus the 14,000. So, you kind of lost 1,000 barrels a day in the very early stages of those new projects. So, then he brought his revised plan and said, “I found an error in my predecessor’s calculations and I think these need to be adjusted.” So, they’re still producing over nameplate from the start, so they’re still good, but the assumption that we used in budgeting for them dropped about 1,000 barrels a day in the early stages. It yet remains to be seen, as I say, whether that turns out to be a careful calculation that was found in error or just a new leader of business who wants to sandbag his plan a little bit in the early stages, but we’ll see. To be fair to him, his predecessor was quite a sandbagger until the end, too, so.

**MALE SPEAKER:**

Frank McGann from Bank of America Merrill Lynch. If I could go back to Slide 13, where you have the breakeven trajectory, which is fairly impressive, going to \$37 by 2022, I have two questions on that. First, there is a sharp acceleration of improvement post 2019. Is anything driving that? Is it mix issue? Secondly, could you remind us what your inflation assumptions are in that time horizon, particularly, with oil prices where they are?

**ROB PEABODY:**

Okay. Could I pass that to Jeff?

**JEFF HART:**

Yes, there’s a couple things there. We’ve got—obviously, Andrew has 60,000 barrels a day in development at that time, and we’ll have through the end of this year into next year, through the end of next year, three projects coming on, and then we’ll be continuing down that path, so that’s a piece of it, and near the end of the plan, obviously, you have 29/1 coming on, as well, here, and West White Rose. So, all of those, if we talk about the thermals, they drive our operating costs down, and the Offshore projects really utilize the existing infrastructure, and those investments are really seeing—that’s where you’re seeing the margin capture go and the cost structure come down as we execute the capital growth.

On the inflation side, if you look at what we’ve done—and we talked a little bit to the service side—is we’ve been able to mitigate that with the amount of rigs we’d be running and our sustaining capital. We are seeing slight pressure on the commodity side, but, again, we’ve talked about, and Carmen touched upon, a little bit of the sustaining capital and the efficiency

and the new phases at Sunrise, and so we are across the board seeing efficiencies and reduced structure and size of the developments, which is alleviating the pressure on the commodity side, the steel and the like.

**ROB PEABODY:**

Yes, it's fair to say, I mean, just looking at—I asked this question of Procurement before we went off. What we are seeing out there, it's actually pretty small because of the way we operate the business, but for services, we're getting requests for increases of about 5% to 10% on unit rates. We're normally able to push those back and reduce those by about half. For materials, we're seeing, I think, between 2% and 9% in the cost of, say, something like an OTSG or a steam generator for our thermal projects. For commodities, we're seeing in steel and things, largely due to both U.S. tariffs and trade pressures, and some rise in cement prices, with higher energy that goes into that, of about a 5% increase. But, our overall impact on annual spend coming out of those requests coming out of the suppliers is about \$175 million affected by increases—of our total spend, about \$175 million is affected by these increases, and it increases that \$175 million by about \$6.2 million. So, that's what we're seeing right now, sort of net-net about a \$6.2 million increase coming from kind of the rising pressure going from '17 to '18, and, really, as has been described, I hope, in most of the presentations, we're offsetting more than that at the moment through just the nature of our business and the structural improvements we're making, and the efficiencies we're driving by doing things again and again and again, where we continue to see real benefits from that.

Any questions? There's no more questions. People must be getting hungry. Just to say thanks for your questions.

To sum up, we continue to deliver against the plan we set out at this event last year, and I hope you'll pick up that theme. We're not trying to set out a new plan, we're trying to report on a plan we set out last year. The investments we're making in our portfolio are further improving our cost structure and bringing down the oil price we need to break even on earnings, which in turn is increasing our funds from operations and our free cash flow. We have a large inventory of projects that will drive our growth over the next five years and beyond, and we have one of the strongest balance sheets in the industry, which, in this volatile world, we think really positions us to execute on the path ahead.



So, thanks again for sharing your morning with us and we hope you'll stay around for a chat and ask us all those really interesting questions you didn't want your colleagues to hear, and also have a bite to eat. Thanks.