OVERVIEW:
Co. reported 1Q17 consolidated profit of $58m or $0.34 per diluted share.
CORPORATE PARTICIPANTS

John W. Eckart  Murphy Oil Corporation - CFO and EVP
Kelly L. Whitley  Murphy Oil Corporation - VP of IR & Communications
Roger W. Jenkins  Murphy Oil Corporation - CEO, President and Director

CONFERENCE CALL PARTICIPANTS

Arun Jayaram  JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst
Guy Allen Baber  Simmons & Company International, Research Division - Principal and Senior Research Analyst, Major Oils
Kyle Rhodes  RBC Capital Markets, LLC, Research Division - Associate
Roger D. Read  Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst
Yim Chuen Cheng  Barclays PLC, Research Division - MD and Senior Analyst

PRESENTATION

Operator

Good afternoon, ladies and gentlemen, and welcome to the Murphy Oil Corporation First Quarter 2017 Earnings Conference Call. Today's conference is being recorded.

I would now like to turn the call over to Kelly Whitley, Vice President, Investor Relations and Communications. Please go ahead.

Kelly L. Whitley - Murphy Oil Corporation - VP of IR & Communications

Thank you, Dana. Good morning, everyone, and thank you for joining us on our call today. With me are Roger Jenkins, President and Chief Executive Officer; and John Eckart, Executive Vice President and Chief Financial Officer.

Please refer to the information on slides we have placed on the Investor Relations section of our website as you follow along with our webcast today. John will begin by providing a few -- a review of our first quarter financial results highlighting our balance sheet and strong liquidity position, followed by Roger with the first quarter highlights and operational update and outlook, after which questions will be taken.

Please keep in mind that some of the comments made during this call will be considered forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995. As such, no assurances can be given that these events will occur or that the projections will be attained. A variety of factors exist that may cause actual results to differ. For further discussion of risk factors, see Murphy's 2016 annual report on Form 10-K on file with the SEC. Murphy takes no duty to publicly update or revise any forward-looking statements.

I'll now turn the call over to John for his comments.

John W. Eckart - Murphy Oil Corporation - CFO and EVP

Thank you, Kelly, and good morning, everyone. Consolidated results in the first quarter of 2017 for Murphy Oil were a profit of $58 million, $0.34 per diluted share, as compared to a loss of $199 million or $1.16 per diluted share a year ago. Results from continuing operations had a profit of in the first quarter '17 of $57 million, $0.33 per diluted share. The first quarter results from continuing operations for 2017 included a $96 million after-tax profit from the sale of Canadian Seal heavy oil assets in the quarter. Quarter 1 also included an approximate $55 million noncash tax charge related to an expected future U.S. repatriation of 2017 earnings in Canada and Malaysia.
Adjusting our GAAP numbers for various items of the comparability of results between periods led to an adjusted loss of $10 million or $0.06 per diluted share in the first quarter 2017. Our schedule of adjusted loss is included as part of our earnings release and the amounts in this schedule are recorded on after tax basis.

Beginning in the first quarter 2017, the company determined that current earnings from foreign subsidiaries with operations in Canada and Malaysia would not be considered indefinitely reinvested in those local operations. A corresponding noncash tax charge of approximately $55 million was recorded in the first quarter of ’17, based on the expected tax impact under existing U.S. tax law from the future repatriation of these Canadian and Malaysian profits to the U.S. through dividends. The tax charge also includes the anticipated 5% dividend withholding tax applicable to all Canadian repatriations. Under current law, the future repatriation would be considered U.S. taxable income which would reduce the future benefit of U.S. net operating losses generated by the company’s domestic business. The company’s average realized sales price for its crude oil production was $50.10 per barrel in the first quarter 2017. This average benefited from our historically strong market prices for our Malaysian oil.

Also, our overall natural gas liquid prices in the U.S. and Canada averaged $17.01 per barrel. Natural gas sales prices in North America averaged $2.17 per thousand cubic feet in the first quarter, while realized oil index natural gas prices offshore sale rack averaged $3.50 per MCF. At March 31, 2017, Murphy's total debt amounted $2.98 billion, that includes capital leases. This makes it slightly below 38% of total capital employed, while net debt amounted to slightly less than 28% of capital employed and amounted to $1.9 billion. As of March 31, we had no outstanding borrowings under our almost $1.1 billion revolving credit facility. Worldwide cash and invested cash balance totaled $1.1 billion at quarter-end.

That concludes my comments. I’ll pass it over to Roger.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Thank you, John. Good morning, everyone. Thanks to those who are on call today. Murphy started the year an all-around solid first quarter. We produced 169,000 equivalents comprised of a balanced mix between onshore and offshore production. Offshore productions comprised of 73% liquids as compared to onshore business which is 51%. Our onshore developed plays continue to exceed our production expectations. Both our offshore and onshore liquids are high-value barrels and they received a premium pricing based on Brent for offshore business and LLS for U.S. onshore. And our new Kaybob Duvernay shale play receives current condensate net box just below Eagle Ford Shale prices.

For the quarter, the company spent just over $214 million in capital, which is in line with our capital budget of $890 million for the year. We continue to strengthen our capital efficiencies which we worked hard to achieve over the last 2 years. With the solid balance sheet and the liquidity cash on hand, we continue to build positive financial momentum as we progress through the year. Our diverse asset-based and oil related premium pricing drives our continued strong EBITDA per BOE performance. In the first quarter, we achieved $29.50 EBITDA per BOE and excluding our pretax gain on the Seal divestiture, we achieved just over $20 EBITDA per BOE.

Operationally, we are successfully executing our 2017 plan across all our assets. The early appraisal wells in the new Kaybob Duvernay play are yielding positive results. We’re now just beginning to drill and complete the wells with our plans in our way. In Eagle Ford Shale play, we’ll continue to derisk the Austin Chalk in an effort to put shales on. In the Karnes area continues to see well results exceeding expectations across at that play. Our Tupper Montney natural gas play has exceptionally low operating and execution cost, making it more attractive to consider accelerating production and bringing value forward.

In offshore business, we continue to execute on highly economic production optimization projects. We continue to evaluate numerous exploration projects as we believe that entering these types of plays with low expense entry at the bottom of the cycle is minimum, that cost will hence long-term value.

We’ll now look at the first quarter in more detail. We produced over 169,000 equivalents at the high end of our quarterly guidance. Our better-than-forecasted first quarter volumes are primarily due to stronger base and new well production in the Eagle Ford Shale, even with fewer wells brought online than originally planned. We also had higher natural gas sales offshore sale like Malaysia, strong field performance in the Gulf of Mexico and better than planned uptime in Block K Malaysia. These were partially offset by delay in additional plant compression and the initiation of royalty this year at the Montney project and downtime in offshore Canada. The annual 2017 capital program is being maintained at $890 million.
Full year 2017 production guidance is being maintained at 162,000 to 168,000 barrels equivalents per day with onshore production expected to increase by approximately 9% as per our original plan. Production for the second quarter 2017 is estimated to be in the range of 160,000 to 164,000 barrels equivalent per day.

In offshore business, we produced 84,000 equivalents for the first quarter with 73% liquids, and our Malaysia business Block K and Sarawak produced 38,000 barrel equivalents per day during the quarter with natural gas production at Sarawak averaging near 120 million per day.

Operationally, we’re executing on our planned production optimization at KiKeh and a planned water injection oil at our South Acis field in Sarawak. In our Gulf of Mexico and East Coast offshore Canada production the fourth quarter averaged 25,000 equivalents per day with 92% liquids. Commingling of the 2 zones of the nonoperating Kodiak field began early in the quarter. Following the project, we’re now producing close to 2,000 barrel equivalents a day ahead for the fourth quarter 2016 production for this field.

Along with our partner Chevron, we’re planning to sidetrack over the Mississippi Canyon 166 Hoffe Park discovery prior to year-end. We have a 25% nonoperating working interest in the previously announced discovery. Also in the Gulf of Mexico, we’re progressing with the environmental approval process for our highly-contested Mexico deepwater Block 5 with plans to spread first exploration well in late 2018. We have purchased new seismic of the acreage which is giving us new positive insight into prospectivity on this block.

During the second quarter, we’re drilling 2 Wells in Vietnam Block 11-2. Currently, the wells are progressing to plan. Late in the second quarter, we’ll be drilling a third well with our partner, PetroVietnam, near our LDV discovery in Vietnam Block 15-1. This well has much promise for us as we again be able to test our naturally fractured sandstone play in prolific Cuu Long Basin.

In Eagle Ford Shale, first quarter production averaged over 46,000 barrel equivalents per day with 88% liquids. There were 13 new wells brought online, of which 3 were Austin Chalk, 4 were Upper Eagle Ford Shale and 6 were Lower Eagle Ford Shale. We are able to meet our first quarter production guidance of 2 wells online in plan as our base production along with new wells continue to outperform expectation. Eagle Ford Shale production will gain momentum as we continue to ramp up our completion plans. We plan to bring 59 additional wells online this year with 19 in quarter 2, bringing our whole year well count to 72. Our focused area through the rest of the year will be our tried-and-true Lower Eagle Ford Shale zones in the areas of Tilden, Karnes and Catarina. We announced our fourth quarter Eagle Ford Shale production approaching 54,000 barrel equivalents per day. Our Karnes wells, both upper and lower, are producing above their expected type curves which were up for Upper Eagle Ford wells that we brought online in the first quarter achieved an average IP30 of over 1,200 barrels equivalent per day, which is leading to continued production for our recent Upper Eagle Ford Shale wells in Karnes striking 47% above expected type curves.

The 6 Lower Eagle Ford Shale wells that were gone online in the quarter achieved an IP30 of over 1,300 barrels equivalent per day which is leading to recent Lower Eagle Ford Shale wells in the Karnes area, tracking some 45% above the 505,000 BOE type curve we have. As we gain additional production history over the course of the year, we’ll make upward revisions to our EUR, which will increase our net resource and lower our breakeven well cost further. All the better well performance points to continued success with many technical advances, including high-sand concentration and tighter clusters in our completions. We continue driving down our operating expenses better in water disposal, infrastructure and field [interpretation].

Operating expense for the first quarter was $7.90 per BOE, which is down 6% from the fourth quarter of 2016. We believe our 2017 operating expenses in Eagle Ford Shale will remain around the $7 per BOE figure.

From a drilling perspective, we continue to drill pace at oils with recent Tilden well drilled in almost 5.5 days.

As we progress, our Austin Chalk delineation program, we’re beginning to clearly respond to sweet spot (inaudible). 2 wells in the pad, we brought online in the quarter in northeastern acreage achieved an IP30 of over 1,100 barrels equivalent per day. The third Austin Chalk well brought online to test the outer rim to play is performing below expectations at present. We’re now focused on the petrophysics landing zone requirement in this area of the play. For the rest of 2017, we’ll complete 5 additional Austin Chalk wells in the Karnes area, 2 in the second quarter, 3 in the third quarter as we further delineate this play.
In Canada, Tupper Montney asset produced 207 million per day for the first quarter during the quarter, with no new wells completed, however, early in second quarter, we brought online 5 new wells. These wells have the longest laterals length to date, they're approaching 10,000 feet as well as higher sand concentrations up to 2,000 pounds per foot. These wells in addition to wells brought online in the fourth quarter of '16 are giving projected with curve is exceeding the '17 BCF type curve.

Currently, the Tupper Montney full cycle breakeven process remain below $2 MCF Canadian AECO with current royalties of approximately 3% to 5%. The Tupper Montney assets continue to drive free cash flow. With continued strong well performance in the asset coupled with excellent economics we're exploring long-term expansion options for the field.

In our Kaybob Duvernay, production for the quarter averaged near 3,000 barrel equivalents per day with 53% liquids, 5 wells drilled and 3 new wells brought online and 2 well pads to test the condensate window and 1 oil pad to test oil area. The 2 well condensate pad utilized higher profit loading an aggressive choke management. These wells are at a sub-optimal lateral length and were drilled in the north-south production. Currently, wells are performing in line with the 600,000 BOE type curve at 42% liquids. A single well oil pad drilled with the 6900-foot lateral section preferred azimuth was brought online is outperforming with 650,000 BOE type curve.

During the quarter, Murphy drilled 2 well oil appraisal play which we brought online during the second quarter with a planned average lateral length of nearly 8,000 feet. The average drilling cost on the pad was $2.7 million and included a pacesetter well of 20 days. Also drilled in the first quarter was a 3-well condensate appraisal pad. The cost of the pad was $3.3 million per well, which is remarkable as we increased the lateral length to over 9,100 feet. We also optimized drilling fluids and we employed higher sand concentrations when we complete these wells in the second quarter. We drilled a step out appraisal well with the longest lateral of date of over 9,500 feet. We plan to complete this well in the third quarter. Needless to say, we’ve been successfully drilling long lateral wells in the Duvernay Shale.

The drilling results place Murphy at the top benchmark of performance with only 5 operated wells drilled in the play highlighting, as we expected, we'll be able to leverage our North American shale expertise across all plays and drive cost down quickly once we move to pad drilling.

Over the course of '17, we continue to gain better understanding with Murphy’s areas within the Duvernay and anticipate we’ll set Murphy on a clear path forward as competitive cost player when we move to full development mode. I’d like to point out, the single 05-29 well that was drilled on a lateral 6,900 feet with optimal azimuth. Well’s performing above the 665,000-type curve with 75% liquids. This is a very successful well for us in core and appraising our oil area as we will now move to longer laterals at this pad site late in this year.

This year, we will drill 16 wells and complete 13. This is 2 more online wells than previously planned. However, total span will remain within our budget of $145 million. For the 13 wells that we complete, 8 will test the oil area and 5 will test the condensate window. We’ll bring on 5 new wells in the second quarter, 3 in the condensate and 2 in the window of our Kaybob West area. Similar to Montney, we're experiencing very low royalties in Duvernay, which are now near 8% and are expected to decrease to 5% for the next few years.

Production in the second quarter is expected to be in the range of 160,000 to 164,000. Production is lower relative to quarter 1, mainly due to planned downtime for maintenance at offshore assets in Malaysia, in the Gulf of Mexico and Canada and the 10-day planned turnaround at our Tupper Montney asset. Production also will be impacted by previously announced redetermination and our nonoperating Kikeh field and a planned entitlement change associated with Sarawak, Malaysian business.

Oil production in second quarter was partially offset by strong performance from recent online wells in Eagle Ford Shale, the new wells we expect to bring online in Kaybob, Duvernay assets during second quarter. The majority of that wells in Eagle Ford Shale we brought online in the second and third quarters are leading to a meaningful midyear production ramp up which will ensure we achieve our full-year production targets and place us with the better than planned exit rate at year-end.

With the first quarter production behind us, 2017 is shaping up to be a good year as we continue to execute our plan. We remain on track to spend within cash flow, while maintaining our current dividend, reserving financial strength and ample liquidity. Also, we're keeping our focus on cost and capital spend, while stabilizing production service foundation for future growth. In Eagle Ford Shale, we continue to delineate multiple zones.
while driving greater efficiencies across the play. The results from our Upper Eagle Ford and Austin Chalk wells are still improving, leading to an increase in our recoverable resources.

The Duvernay shale, in the early stage is successfully executing our appraisal plan, enthusiastic as we start to move forward with our future development plan in the play. Offshore participating high return offshore project, we’re seeing many opportunities at the bottom of this cycle. We’re returning the exploration in a measured way in the Gulf of Mexico and building on our successful plan in Vietnam. We’re also focused on additional business development opportunities for both offshore and onshore areas that resemble our [existing] assets.

And I remain very pleased with my team’s execution so far in ’17. Again, we’re achieving high margin and EBITDA per BOE metrics, which is a benefit of our diverse asset base. We’re maintaining capital discipline to ensure we preserve our balance sheet. Our developed onshore assets continue to outperform as we employ higher sand concentrations fracs and longer lateral wells. As we begin appraising our Kaybob Duvernay play, we’re transferring knowledge from our Eagle Ford Shale and Montney assets to ensure we quickly move up the learning curve to drive future production growth. Offshore execution really is one of our competitive advantages and we’re looking to expand our offshore exploration portfolio at the bottom of cycle to build on our execution advantage, primarily in low risk tieback opportunities that are highly economic. As always, we are paying close attention to the business development opportunities in both onshore and offshore going forward.

This concludes my remarks and I’ll be open for your questions.

QUESTIONS AND ANSWERS

Operator
(Operator Instructions) And we’ll go first to Paul Cheng with Barclays.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Roger, do you have a rough per well cost estimate for the well you’re going to drill in Vietnam and also Mexico?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

The wells in Vietnam are 2 wells which should be approximately 20 million to 25 million our share. And the well in Mexico next year is probably set up for around that same spend.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

And your working interest, I’m sorry, can you remind me?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

In the Vietnam areas, we’re 60% and we’re carrying part of the cost for our partner, paying them around 80% on 60% in those wells. And after end of those wells, there will be no further carry in the project.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Okay. And your Mexico?
Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Mexico well probably be -- we're trying to target now opportunities that are economically large and hit our F&D targets and our economic thresholds. And we're probably looking at all the wells participating in around $18 million to $20 million our share. And that's top exposure we're willing to put into these plays and they'll be no different in Mexico.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Okay. And can you share with us what is the end cost --I assume that even in Eagle Ford we start to seeing some cost inflation? What are the cost inflations we're seeing in there now?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Well, to explain that issue, I'm sure they'll be asked that if you look at first quarter '16 to first quarter '17, we're actually lower on our costs in Eagle Ford on a true average date of both drilling and completion. But we haven't seen that break into us yet. We continue to see efficiencies in our drilling, probably -- we've been doing 10% here and we just continue to set the pace at our wells. Now worst case scenario, we see that the fracturing -- just the fracturing side can go up 30%, smaller increases in everywhere else. We start to see this deal around the possibility of a 10% increase per well, that's around 400,000 of well for us. And we're going to drill 60 -- drilling complete, 60 more wells this year. So for us, that's like a 24 million possible change. As we look at the efficiencies continue to set pace their wells, working on some new motor technology, we're also noticing that our stages per day is going up from a year ago, 6 stages a day to 7. We're also working on some other plans that we have on technological basis to employ fractures. And I see us being able to work that off. And I see our fracturing cost and the deals that we have with various vendors, including rigs and fracturing to place us in a pretty good situation there. It's not detrimental to the company at all. We handle this, we go up and down with this as needed and it's going fine for us.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

My final one is that, have you seen any cost inflation in your Canadian operation?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

It's probably on a different scale. The equipment is tied, but there is not as much activity with the breakup seasons and various things of that nature. We're probably exposed there, probably $10 million to $15 million for the whole year. I just don't see this in our current procurement over the next couple of years. I'm just not that concerned on that issue at this time.

Operator

And we'll take our next question from Guy Baber with Simmons.

Guy Allen Baber - Simmons & Company International, Research Division - Principal and Senior Research Analyst, Major Oils

I was hoping you could talk a little bit more about the capital spending framework for this year. I understand you reiterated the full year guidance and the 1Q total CapEx number, which is generally in line. But there were some regional variances. CapEx in Canada was higher than we expected. So can you speak to that at all? What might be driving that? On the other hand, Malaysia was much slower. So if you can put some color around some of the trends there, that will be very helpful.
Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

I think these trends, from our original outlay, that Kelly shared with you earlier in the year should not change. It's strictly timing issues. Actually, our capital is a little bit low in the first quarter as we didn't complete 6 wells in the Eagle Ford, that would have cost probably around $3 million a well. And we'll be hitting that hard in the second and third quarter with the lower execution amount of wells in the fourth quarter. So I don't really see any regional change overall for the year, just strictly a timing issue and not something we see as changing or trend or anything like that, Guy.

Guy Allen Baber - Simmons & Company International, Research Division - Principal and Senior Research Analyst, Major Oils

That's helpful. And then I wanted to talk a little bit more about the Eagle Ford as well, but it appears that while the first half of the Eagle Ford was maybe a little bit lower than we have assumed on completion timing, the second half is going to be a little bit stronger. Can you just talk about that trajectory for the Eagle Ford as we exit this year and head into 2018? And should we still be thinking about revised whole unit production in the low 50 range? Or given some of the low results, does that look like you could be growing it at some of these activity levels? Or if you have an opportunity to add the activity there?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Actually, it's going very well. We just had some -- we had some delays in putting some wells fractured and made some different changes in the who we're using what we're doing in the fracturing leading to some higher well counts in the second and third quarter. We are looking at a higher exit rate than we originally had before in the play, probably looking at pretty strong 58,000 coming out of it in the fourth quarter. And originally, it started to be 2,000 to 3,000 less than that. And happy with how that's going, I think that's possible to have a slight increase next year or maybe not as flat as we originally thought. But then we have working capital and making the asset free cash flow we're trying to make our developed Eagle Ford plays and Montney plays be free cash flow providing and we have that in the back of our minds as well. So haven't really worked into what it will look like in '18, but we definitely not decreasing. We're flat to slightly growing at this time. We're just getting in new wells into our plans at this time.

Operator

We'll go next to Roger Read with Wells Fargo.

Roger D. Read - Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst

Real quick. You talked about -- and it's been a consistent theme for, I guess, the last year or so. Doing an acquisition or a way to buy into some of the offshore opportunities that others are trying to exiting. Have you seen improvement in, say, a bid-ask spread or a narrowing or broadening of opportunities over the last 12 months? I'm just kind of -- since we haven't really seen a huge acquisition anywhere other than Anadarko. So I'm just curious, there hasn't been much movement out there.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Let me correct something I just told Guy. I told him that our fourth quarter in Eagle Ford will be 58,000, actually 53.8, Guy. I apologize I misread that number there, I don't have my glasses on. We're very active, Roger, in looking at these opportunities offshore and onshore. We like -- we look at our strategy, we like to take a differentiated perspective looking in basins in place that we can have rate of return with strip with a conservative view of EUR and conservative pricing. That's our mantra, that's our company, that's our history, that's what we do. And we continue to focus on these and we have opportunities all the time that we are reviewing both onshore and offshore. And looking to be in the accumulator in the Gulf if we could find some acreage that we could operate well and looking for things in the onshore that would complement where we're working at very near, where we're working and methodology of things we're executing. And all I can tell you is we're very active at doing it and we're -- see it as a key part of my focus at this time.
Roger D. Read - Wells Fargo Securities, LLC, Research Division - MD and Senior Analyst

All right. Well, I guess I can push harder on that. But I am going to ask my other unrelated follow-up. The Austin Chalk wells in the Eagle Ford area, you gave a volume on that. Did you offer a percent liquid gas content there or maybe how these first...?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

It'll be just like our -- it's just like our Eagle Ford wells in high 80s. It's really no different. There's a different crude means coming in formulating in a different way but it's slightly different gravity. It's very low, very high-quality. But it's the same kind of crude percent we have, pretty strong oil for our business.

Operator

And we'll take our next question from Kyle Rhodes with RBC.

Kyle Rhodes - RBC Capital Markets, LLC, Research Division - Associate

A couple of questions on the Eagle Ford. Any chance you could break down the remaining 6 Eagle Ford wells expected to be turned in line before year end '17 between Karnes, Catarina and Tilden, maybe just a rough split there?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Let me -- I have to dig for that. Kelly is going to dig for that. Do you have another question you can ask while we pull that up?

Kyle Rhodes - RBC Capital Markets, LLC, Research Division - Associate

Yes, sure. You mentioned base production kind of outperforming expectations. I know you were straight little bit more than some of your peers there. Can you quantify maybe what you -- you think your update to annual base decline in the Eagle Ford is?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Eagle Ford decline is very similar to what it's been. We're looking at the year 1 decline there, somewhere around 30, year 2 is around 15 and year 3 about the same. And these shale plays, it's not really a true decline rate like in offshore asset and that's the decline we have from the wells. So it would be like our new well online decline as those types of factors. New wells on top of that base, if you get me, is 31%. And it depends on how many wells you add and how many older wells you have and things of that nature. That's where we have it today.

Kyle Rhodes - RBC Capital Markets, LLC, Research Division - Associate

Got it. Okay. That's helpful. And then just maybe on the Montney. You mentioned some potential expansion opportunities out there. What are some of those opportunities? Is there new plant capacity opening up? Just curious how much your ability to grow that asset is.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

We're taking a very close look at it right now because we've been doing so well there. Our drilling continues to improve. Our recovery per well is outstanding. Our operating expenses, they're very good in the $0.60 range in that asset. What we're looking at is to build with a midstream partner...
an additional plant or series of $200 million a day plants originally in our long-range plan, which is not included in the growth plans that we shared in the fourth quarter, we had the expansion of the Montney as late as 2023 and our business containing on that way we're looking to advance that to 2020 and drilling additional wells in 2019. And we're looking at around $100 million of additional capital. We can build up the wells, deliver the new $200 million and we're in feed stages with partners there to look at building the plant where the plant would be and among our field there. And really I like how that's looking and like the moving forward with that cash flow and hundreds of millions of dollars of free cash accumulation by 2030 by not doing status quo of the 2023 expansion and moving it forward by 3 years. And Kyle, it all depends about the price and what we do there and what's kind of modeling up, 2.90 C AECO in 2024 and around 3.20 C AECO in 2030. That's how it is today, but I don't think it's out of bounds. And see how that would look, compare that back to strip prices and compare that to other opportunities and review that with our Board this year, and it's gaining momentum in the company.

Operator
We'll take our next question from Arun Jayaram with JPMorgan.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director
One second. Let me answer the prior question on the wells. In quarter 2, we're looking at 2 Austin Chalk wells in Karnes, 2 wells in Catarina, 12 wells in Tilden. Quarter 3, we're looking at 3 Austin Chalk wells, 14 Eagle Ford Shale wells and 9 in Catarina. And quarter 4, 14 wells in Catarina. In addition of the quarter 2, we will have 5 Eagle Ford shale wells, partnered with the 2 Austin Chalk wells. So go to your question now. I'm sorry for that delay.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst
I wonder to see if you could kind of set the stage for the Duvernay tests? That's pretty important catalyst, I think, for the stock. I know you're going to be drilling and completing longer laterals, but how would you gauge success with these early tests? What kind of KPIs are you looking for from your initial Duvernay tests?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director
We have some preplanned EURs that we see as successful, but it just depends on costs and how things change with the field, as you can imagine. We have -- I think, from a production basis these wells we drill and see on our slide and our deck there and our other public decks. There's 11 of 18 pad, looking for some thousand EUR type wells in there and that would be something we need to be pulling into in the high 7s to 1,000s to how that -- these are some pretty longer lateral wells in a condensate gassy region. I think if you look at this 05-29 well, we have in here today on our 6,000 feet type lateral performing on 600,000 type curve and you put that in between, thereby the 04-32pad seen in our slides, you can kind of see that that's in the 600,000 and 700,000 range. And in and around that, keep in mind, our Eagle Ford wells are 500,000, 600,000 and accompany that with the low royalties, we have very low royalties here for several years in Duvernay cost coming down pad drilling. This is working. There's an enough data to show it's working now and I'm not going to be put off by a singular pad result at this time. We're experimenting with about 3 different ways to frac, 2 different ways to flow back, 2 different type of staging, doing a gel type frac, slick water type fracs, 3,000-pound per foot fracs, 2,000 pound per foot fracs. So we got a lot going on in there in a planned way. And on and off on 1 particular pad being the driver of our stock price in the middle of Canada, I don't see that as a big driver today. But overall, we're real happy with how we're doing and just got to look at our holistic year of delineation in that play.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst
Okay. Fair enough. But do you agree, it could be a longer-term driver of growth at Murphy?
Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Sure. For sure. What we're trying to take all our learnings from all our other plays, have a systematic approach into this, just jumping in and completing 12 well pad at a certain way, a certain spacing, at certain frac design and find out later that wasn't the way to do it. And our walk across this play and these different attributes of the technological changes in frac-ing that we learned from other areas is slowing this into something we can have a better value, better down spacing, better total design of the pads going forward if we learn from other areas.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst

Fair enough. 2 other quickies. One, as we think about the Q2 guide, just kind of 8 MBOE per day and kind of quarter-specific items, how much of this is kind of known guys when you gave out your guide? Just trying to understand as we think about your full year range in some of the unexpected and one that could also influence how I think about where we land in terms of our updated model.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Downtime comes and goes on schedules to do things. The second quarter always has a lot of downtime for an offshore company. That's very typical. We're absolutely new in plan for the redetermination and for the entitlement change. On these entitlement changes, first off, you have to make a lot of money for them to click in. And that's going very well from us on our revenue oversee basis overall. And that's been known and the only change in the second quarter from our original guidance would have been a change in the completion timing of Eagle Ford just more backed into late May. We have another crew starting in Texas. And that's the only change to our original plan. And now with our better base production in Eagle Ford, looking at a pretty strong exit at the end of the year. And the only change is that timing of fracs, all the other issues are known and planned and no surprise to me in any way.

Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst

Okay. Fair enough. And just Roger, as we think about Hoffe Park, which sounds like you'll be doing a sidetrack there, can you give us a sense of -- is that in the longer-term guidance for production that you should I think in (inaudible) -- okay.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

No. No expiration in that number.

Operator

(Operator Instructions) We'll go next to Pavel Molchanov with Raymond James.

Unidentified Analyst

This is Michael in for Pavel. I have a question about Block 5 Mexico. It's been about 5 or 6 months since you won that block and what...

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

I'm sorry, I'm having trouble hearing you. Can you speak up a little louder?
Unidentified Analyst

Yes. We have a quick question about Block 5 in Mexico. We're just curious what the status was and if there is a timetable for the first exploration well and maybe any seismic you'll be doing in advance to that.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

We just purchased some new wide azimuth seismic over our block -- a large portion of the block. This block is very large, over 100 Gulf of Mexico normal blocks in the U.S. side. I'm very happy with those images. This play is a very nice block for us. It would have classic Gulf of Mexico attributes such as amplitude, plays three-way plays against salt, four-way closure. It would have every play type that we've seen in the Gulf of Mexico, including sub-salt, which is very unexplored in that entire country compared to the U.S. I'm very pleased with those images. Pleased with the prospects we have. Our partnership group, our exposure we have in the block will not be high percent and guiding ground for in it. And most contested block in the sale and we're looking to drill the well in late '18.

Operator

And we have a follow-up question from Paul Cheng with Barclays.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Roger, 2 quick ones. First, Malaysia, the floating LNG. What's the status right now on that one? Are we still talking about start up in the 2020 or that being further pushed out?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

No. That's progressing well. If you know the history of these projects, there were 2 floating LNG boats produced by Petronas. Petronas is the leader in delivering these boats on time. The first boat is just like our vessel, which they own, has been working in Malaysia now already and went through the critical derisking of offloading LNG recently. It's a very large turret associated with this vessel. It’s manufactured out of the country and has been transported to Korea now. And we're all systems go to defer Petronas to place that vessel and produce in 2020. We then will spend money in '18 and '19 with the completion of the wells, we'll be delivering the gas molecules to the edge of the boat for Petronas, just as we do in shallow water where we deliver LNG to them at the doorstep of their LNG plant onshore in Malaysia in Sarawak. So going well, they're back in line doing the project. I believe the Petronas sees advances and possible ability of LNG price to increase past 2021, 2022. And that's helping with that project. That's helping bring -- hopefully, we can bring for a Brunei project. I think there's a little bit of improvement in LNG in that region. They're the leader. They're the king of the road in LNG in Southeast Asia and I like falling behind Petronas in that.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

If the scope of the project and the changes, do it still get about 100 million cubic feet per day for you?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

With our sale down in Malaysia few years ago, it should be about the same level than that production we have in Sarawak today and should go for several years.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

Okay. And in Malaysia that -- when Block K and Sarawak going to hit the 50% -- profits go down to 50%? Is that 2000...
Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

The change out in Block K has been around the company for a long time. I believe now it's out in 2021 or something to that effect. We have no additional changes in entitlement in Sarawak. We have an entitlement change in the third quarter of '18 in Block 309 oil, nothing again until fourth quarter of '19 for 311 oil. No change on 311 gas until 2021 and we just made a change in 309 gas, which is primarily the BOE benefactor of this reduction. And that won't change for -- I don't have numbers long enough to know the when the next change is there. So pretty stable for a good while in Malaysia this time.

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

And maybe Kelly, if you don't mind, maybe can you send us an e-mail maybe helping us in terms of when that happen, when the change happens. What kind of production impact we may be talking about? And then the other one. On the M&A side, is there any other opportunity in the Duvernay that you can see?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

In what area did you say?

Yim Chuen Cheng - Barclays PLC, Research Division - MD and Senior Analyst

In the Duvernay?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Duvernay, I got 140,000 acres, 2,000 acres in there now and got my hands full doing that. I'm real pleased with it. We do see some opportunity. Just sometimes when things happen and we do not announce that we did something, it means we didn't bid for us. So we look at many things and try to get many things here and we'll continue to do so.

Operator

And at this time, I'd like to turn the conference back over to Roger Jenkins for any additional or closing remarks.

Roger W. Jenkins - Murphy Oil Corporation - CEO, President and Director

Have no further in-line calls today. Appreciate everyone calling in and I know it's a packed time of earnings this week. And we'll get back to work here in El Dorado and appreciate it. And we'll talk to you at the end of next quarter. Thank you very much.

Operator

Thank you. And that does conclude today's conference. Thank you for your participation. You may now disconnect.
DISCLAIMER

Thomson Reuters reserves the right to make changes to documents, content, or other information on this web site without obligation to notify any person of such changes.

In the conference calls upon which Event Transcripts are based, companies may make projections or other forward-looking statements regarding a variety of items. Such forward-looking statements are based upon current expectations and involve risks and uncertainties. Actual results may differ materially from those stated in any forward-looking statement based on a number of important factors and risks, which are more specifically identified in the companies’ most recent SEC filings. Although the companies may indicate and believe that the assumptions underlying the forward-looking statements are reasonable, any of the assumptions could prove inaccurate or incorrect and, therefore, there can be no assurance that the results contemplated in the forward-looking statements will be realized.

THE INFORMATION CONTAINED IN EVENT TRANSCRIPTS IS A TEXTUAL REPRESENTATION OF THE APPLICABLE COMPANY'S CONFERENCE CALL AND WHILE EFFORTS ARE MADE TO PROVIDE AN ACCURATE TRANSCRIPTION, THERE MAY BE MATERIAL ERRORS, OMISSIONS, OR INACCURACIES IN THE REPORTING OF THE SUBSTANCE OF THE CONFERENCE CALLS. IN NO WAY DOES THOMSON REUTERS OR THE APPLICABLE COMPANY ASSUME ANY RESPONSIBILITY FOR ANY INVESTMENT OR OTHER DECISIONS MADE BASED UPON THE INFORMATION PROVIDED ON THIS WEB SITE OR IN ANY EVENT TRANSCRIPT. USERS ARE ADVISED TO REVIEW THE APPLICABLE COMPANY'S CONFERENCE CALL ITSELF AND THE APPLICABLE COMPANY'S SEC FILINGS BEFORE MAKING ANY INVESTMENT OR OTHER DECISIONS.

©2017, Thomson Reuters. All Rights Reserved.