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MUR - Q3 2017 Murphy Oil Corp Earnings Call

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OVERVIEW:
Co. reported 3Q17 consolidated loss of $66m or $0.38 per diluted share.
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Roger W. Jenkins  
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PRESENTATION

*Operator*

Good day, ladies and gentlemen, and welcome to the Third Quarter 2017 Murphy Oil Corporation Earnings Conference Call. (Operator Instructions) As a reminder, this conference is being recorded.

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

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

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 informational 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 highlights of third quarter financial results, followed by Roger with operational highlights from the quarter 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 now turn the call over to John for his comments.

John W. Eckart  
*Murphy Oil Corporation* - Executive VP & CFO

Thank you, Kelly, and good morning, everyone. Our consolidated results in the third quarter of 2017 were a loss of $66 million, which equates to $0.38 per diluted share. That compares to a net loss of $16 million or $0.09 per diluted share in the same quarter 1 year ago. Our adjusted loss, which adjusts our GAAP numbers for various items that affect comparability of results between periods, was a loss of $6 million or $0.03 per share in the third quarter of 2017. Our schedule of adjusted loss is included as part of our earnings release, and amounts in this schedule are reported on an after-tax basis.
Our balance sheet continues to show low leverage with ample liquidity and manageable debt maturities. At September 30, 2017, our total debt was $2.9 billion or 37% of total capital employed, while net debt was 28% of capital employed and amounted to $1.9 billion.

At the end of the third quarter, we had no outstanding borrowings under our $1.1 billion revolving credit facility, and our cash and cash equivalent balances total $1 billion.

During the quarter, we issued an 8-year $550 million note with a 5.7% -- 5.75%, excuse me, coupon rate. The net proceeds from the offering of the 2025 note were used to redeem the company’s $550 million notes that were scheduled to mature originally in December of this year. Following the redemption of these notes, Murphy’s next note matures in 2022.

In order to underpin our cash flow, we hedge a portion of our oil and forward sell a part of our Canadian natural gas production. As of October 31, we had 22,000 barrels per day hedged at $50.41 per barrel for the fourth quarter of 2017 as well as 7,000 barrels per day hedged at $51.92 per barrel for 2018.

As for natural gas, we had 124 million cubic feet per day forward sold at AECO at CAD 2.97 per MCF for the balance of this year as well as 59 million cubic feet per day at AECO CAD 2.81 per MCF for 2018 through 2020. We have also contracted for 20 million cubic feet per day at Chicago City Gate at a USD 3.51 per MCF for the period from November 2017 to March 2018.

That concludes my comments. Roger will now present a review of the company’s operations.

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

Thank you, John, and good morning, everyone, and thanks for calling in today. In the third quarter, we produced 154,000-barrel equivalents at 60% liquids. Our onshore business provided 55% of our production, offshore provided 45% of production and offshore generated $156 million of free cash flow in the quarter.

We’re able to maintain $1 billion of cash and cash equivalents on our balance sheet this quarter. More importantly, we’ve been able to maintain this level of cash for 4 consecutive quarters, all while funding our capital program and paying a consistent dividend to shareholders. We’ve been able to do this at modest oil prices, as dated Brent has averaged approximately $51 for the last 4 quarters.

Our diverse oil-weighted asset base provides a competitive margin with premium pricing, with third quarter adjusted EBITDAX of near $23 per BOE. We continue to drive down our operating costs by creating sustainable efficiencies, achieving a decade-low quarterly LOE of $7.58 per barrel.

During the quarter, we took measured steps to enhance our portfolio through new, low-cost, onshore and offshore entries that are aligned with our strategy. In the onshore, we announced a strategic entry into Midland Basin. This low-cost entry will increase our oil-weighted future location count of low-breakeven wells and allows for capital allocation flexibility. We’ve accumulated approximately 31,000 net acres via organic leasing in prior quarters and successful bids in recent lease sale. We also announced entry into the Sergipe-Alagoas Basin Offshore Brazil with our co-venturers ExxonMobil and QGEP. In the Gulf of Mexico, we acquired the Clipper Field, which has 2 wells that flow to our Front Runner facility.

Looking more at the quarter in detail. Our third quarter production was negatively affected by approximately 5,100-barrel equivalents per day by the following temporary factors: Eagle Ford Shale partial shut-in and delayed completions in conjunction with midstream and refining issues associated with Hurricane Harvey, 2,700 barrels; Canadian offshore extended turnaround time and unplanned downtime, another 1,800-barrel equivalents; and our Tupper Montney natural gas downstream curtailments from TransCanada Pipeline were approximately 600-barrel equivalents.

Production in the fourth quarter is expected to be in the range of 170,000 to 172,000-barrel equivalents per day. Fourth quarter production guidance is above third quarter actuals due to minimal scheduled downtime and turnarounds, a full quarter of production from our Clipper wells in the Gulf, the planned production ramp attributed to bringing on 15 wells in the Eagle Ford, 5 wells in Tupper Montney and 3 wells in Kaybob. Our fourth quarter guidance also accounts for 1 week of Gulf of Mexico shut-ins for Hurricane Nate. We’re tightening our full year production to a range of 164,000 to 165,000 a day equivalents.
We're increasing our 2017 capital program to $940 million. This includes $37 million from Midland Basin acreage, along with drilling and completions and core analysis, $6 million for our entry into the Sergipe-Alagoas Basin as well as $7 million for the acquisition of Clipper Field in the Gulf.

Since we have minimum exposure to WTI pricing, our diversified oil-weighted business portfolio receives premium pricing. Based on barrels sold in the third quarter, 57% of our production is oil, an additional 6% are NGLs, and both realize premiums that are primarily linked to Brent or LLS, with Brent currently at over $6.50 premium to WTI and LLS just under $6 premium to WTI.

In our Malaysia business, we are currently realizing $60 prices for our crude. Prices we have not seen since mid-2015. Our differential spread is a significant advantage for us, and we expect this to last for the next several quarters.

Offshore business provided just over 68,000 equivalent for the third quarter with 73% liquids. The offshore business had an operating expense of $9.07 per BOE. In our offshore Malaysia business, Block K and Sarawak produced over 32,000 barrels of liquids per day during the quarter, with natural gas production from Sarawak averaging 90 million per day. Production at Sarawak was ramped up after the scheduled third quarter 10-day turnaround, which was executed to plan. And Malaysia assets continue to be a steady cash flow generating business and delivered over $140 million of free cash flow this quarter.

The Gulf of Mexico and East Coast Canada production in third quarter averaged over 19,000 equivalents per day with 90% liquids. A rig is mobilizing now to repair the Kodiak well we discussed in the second quarter. At the nonoperated Terra Nova field, it took significantly longer than planned for the operating fleet's scheduled turnaround. Production at the field now has resumed and is producing at pre-turnaround levels.

In the Gulf, we made a low cost, highly economic acquisition of 2 subsea wells in Clipper. This time, the wells are outperforming our initial estimates and are currently producing approximately 4,600 equivalents per day.

In the Vietnamese Cuu Long Basin, we're working with our partners on a declaration of commerciality process for our LDV discovery in Block 15-1/05 for early next year. We expect to sign a production-sharing contract for neighboring Block 15-02 in early 2018. In the Nam Con Son Basin Block 11-2, we drilled a CM-1X exploration well in adjacent fault block to our CT-1X oil discovery from the second quarter. This well encountered approximately 50 feet of net oil pay, and we're incorporating these results into our ongoing evaluation of the block.

During the third quarter, we entered the Sergipe-Alagoas Basin Offshore Brazil as part of our renewed exploration strategy targeting lower risk, lower working interest blocks with large prospects. We entered into a farm-in agreement with Brazilian-based E&P company QGEP with our existing 2 blocks for a 20% working interest, with QGEP remaining at 30% working interest. And ExxonMobil farming in as operator for the remaining 50%. The same co-venture group successfully bid for 2 adjacent blocks in Brazil's Round 14 lease sale. Across this consolidated 4-block position, Murphy has no well commitments, and we're excited about this new play, which is adjacent to several major Petrobras discoveries with our leads in the same petroleum system and stratigraphic intervals. The group plans to acquire 3D seismic in 2018.

We estimate our total expense in Brazil, including lease bonus payments and seismic, for '17 and '18 to be $18 million, which will prepare us for a drilling decision. We believe we have significant resource opportunity in this play.

In the Gulf of Mexico, we're working on renewing our near to midterm exploration portfolio with low-cost tieback opportunities. In a recent lease sale, Murphy and its partner were awarded Mississippi Canyon Block 556 that contains the Leibniz prospect. We're also working to mature several Gulf of Mexico tieback farm-in opportunities for 2018.

In Mexico Deepwater Block 5, we continue to progress to drilling approvals. Our ongoing analysis for the newly reprocessed 3D wide azimuth seismic has validated our interpretation of multiple leads across the block, with plans to spud our first exploration well late next year.

Together, our Mexico and Brazilian entries expose us to significant net resources for a total estimated cost, including initial drilling expenses, of approximately $65 million over a 3-year period.
In the Eagle Ford Shale, third quarter production averaged 45,000 equivalents per day with 89% liquids. We brought on 3 more wells online than originally planned for a total of 27 wells in Karnes and Catarina, of which 20 – 22 were Lower Eagle Ford Shale, 4 were Upper Eagle Ford Shale and 1 was Austin Chalk. The 14 wells brought online in Karnes had an average IP of 1,245 equivalents per day. And 13 wells brought online in Catarina had an average IP30 of over 1,000 BOE per day.

We continue our focus on sustainable cost reductions, driving third quarter OpEx down to $6.93 per BOE, a record low. We continue to successfully test our Gen 5 completion technique and are seeing production increases of approximately 25% over Gen 4 completions in Catarina. We’re also testing lower downspacing, which can position us to increase our top-tier Catarina locations by 25%.

In the fourth quarter, we plan to bring Eagle Ford – 15 Eagle Ford Shale wells online, of which 3 are in Karnes and 12 are in Catarina. These additional wells are in our core areas and will drive production to highest level seen in 2017.

After an extensive review, we target the Midland Basin for another North American unconventional low-cost entry. Over the past 1.5 years, we’ve been actively leasing acreage in the northern Midland Basin. We’ve organically leased approximately 22,000 acres at 100% working interest in Dawson County, Texas. In addition, we’re the high bidder for 2 tracts in a recent university lands lease sale at 75% working interest with a private partner. This university acreage is located primarily in Andrews County with a small portion in Gaines County, Texas. We now have approximately 31,000 net acres at an average cost of $1,700 per acre in the play. If successful, this acreage position will add over 275 locations to our U.S. onshore portfolio with breakevens under $40 per barrel.

During the third quarter, we drilled, cored and cased 2 wells in Dawson County, with 1 well in Wolfcamp B and 1 well in the Lower Spraberry bench. In the process of completing these wells, initial results from core analysis are positive and confirm oil maturity and porosity in line with our expectations. This is consistent with results from offset peer wells, several of which have IP24 rates of over 1,000-barrel equivalents per day from multiple benches. A review of the data from our wells give us confidence that we can expect similar results across our acreage, including potential upside from multiple benches.

The area around our acreage in northern Midland Basin is very active. Over the past 6 months, within 10 miles of our acreage over 70 permits have been issued and almost 50 wells spud with 6 active rigs in this area.

In Canada, our Tupper Montney asset produced 208 million a day for the third quarter. We drilled 4 wells of a 5-well pad, with the fifth well drilled recently in fourth quarter. The longest lateral drilled in the pad was over 11,000 feet, which is a new record for our onshore business and was also a pacesetter well drilled and cased in just 17 days. We bring these 5 wells online during the fourth quarter of ‘17. In conjunction with our Tupper expansion project, we are progressing with FEED and on track for a 2018 sanction.

As a result of long-term forward sales contracts and other marketing agreements, Murphy achieved third quarter netbacks in Tupper Montney of CAD 2.33 per MCF. We continue to have competitive returns in this play as our full cycle breakeven remains under CAD 2 per MCF, AECO pricing.

Our marketing team has significantly reduced our exposure to AECO prices through a combination of physical access to West Coast through Malin, Midwest through Chicago and Emerson, and the East Coast through Dawn as well as current long-term hedge contract. This means that 65% of our planned 2018 production will not be exposed to unhedged AECO pricing, which we believe positions us favorably compared to other Montney natural gas peers.

In our Kaybob Duvernay asset, production in the quarter averaged 3,700 equivalents per day, increase of 32% from the first quarter of this year. The percentage of higher-margin liquids continues to increase as we drill more wells in the oil window with liquids ratio increasing from 53% in quarter 1 to 65% in the third quarter.

Early in the third quarter, we brought 3 new wells online at the 11-18 pad. Each of the 3 wells were completed with different completion style as part of our ongoing field appraisal that will help us determine the best path forward for development of the play. All 3 of the wells are outperforming their type curve with higher liquids percentage than originally estimated.
This year, we will drill 16 wells, complete 12 and bring 11 online. Our drilling for the remainder of the year will be testing new parts of our acreage in Simonette, Saxon and Kaybob East. 04-32 2-well pad in the oil window was brought online in the second quarter and continues to outperform its estimated type curve of 650,000 equivalents with 75% liquids. The 05-29 pad, also in the oil window, was brought online in the first quarter and continues to flow on trend with an estimated type curve of 665,000 equivalents with 70% liquids. In the fourth quarter, we’ll be bringing 2 additional wells online at the 05-29 pad.

The plans for remainder of the year and looking forward into 2018 will be very active as we will enter the year running 3 rigs. Based on our learnings, we refined our drilling and completion designs for the play which has led to shorter cycle time between spud, production and continuous well improvements. We’re very pleased with our derisking of the southern portion of Kaybob West, and we’ll be bringing online the 16-18 well in the northern part of this area in the fourth quarter.

Let me walk you through a few takeaways from today’s call. We’ll continue to maintain our $1 billion of cash on our balance sheet over the course of 4 consecutive quarters while funding our capital program. We’re returning cash to shareholders through consistent dividend policy. We’re focusing on maximizing value by driving down costs across the company as evidenced by decade-low LOE, underpinned by record-low LOE in the Eagle Ford Shale. We’re enhancing the number of high return onshore well locations for a successful Kaybob Duvernay delineation and new Midland entry. We’re establishing positions in Mexico and Brazil that are lower risk and have appropriate working interest to deliver long-term transformational potential. We’re growing production and achieving competitive full cycle returns.

That’s all of our remarks today. We can open up now for your questions. Thank you.

**QUESTIONS AND ANSWERS**

*Operator*

(Operator Instructions) The first question comes from the line of Ben Wyatt with Stephens.

**Benjamin James Wyatt** - Stephens Inc., Research Division - Senior Research Analyst

Roger, if we can maybe start first with just kind of the Midland. How should we maybe think of kind of the activity in ’18? Is it just going to be kind of a move across the asset base, kind of delineate, similar to how you did this year in the Duvernay? I’m just trying to get a sense of maybe what that activity could look like next year?

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

I mean, it’s real critical what we see in these 2 wells here in one part of the play. Of course, if you look at our slide and our release today, we have 2 acreage positions, one in the northeast and one southwest of that, so 2 big, large accumulations. So we’ll be bringing those wells on. Those would be very interesting to us. And the way to think about Murphy as a $1 billion CapEx company, $1 billion to $1.2 billion over several years, with the onshore business achieving around 70% of the capital and the State of Texas today, probably of that $700 million, probably $400 million of capital. And we consider this an extension of our Eagle Ford business. Driving up from Catarina, it’s about a 7-hour drive, run by the same people, same type of execution. We’re hoping to find a way to enhance more top-tier locations. Of course, we have 600 or more of these locations at $40 oil and probably another 700 at $45 oil breakeven, if that’s a way of tiering, which I think is appropriate. So it’s about low-cost entry, finding new places to allocate capital if these wells are to work or allocate more capital into some tiering in the Eagle Ford to this area. And then we can drill wells in the other portion of the play and see how it goes. And it’s going to be probably into January, February before we tie up just how much capital we have into this play. And – but it’s that optionality of what we plan to spend in the Eagle Ford, and we may allocate more capital here as we see fit.
Benjamin James Wyatt  -  Stephens Inc., Research Division - Senior Research Analyst

Got it. Got it. That's helpful. And then maybe just jumping down to the GOM. You guys previously had talked about the Clipper. Just kind of curious, feels like that could be some low-hanging fruit there to boost production. Just curious kind of what the opportunities look like there. And then if you could just give us a sense of maybe what these wells look like when you purchase and then the uplift you guys are seeing after you maybe put a little maintenance on it.

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

They're unique -- as part of our strategy, we're in different places and we have our ear to the ground and work across the spectrum in the Gulf for 60 years. We have wells that flow to our facilities. Some of those operators are looking possibly to exit or have some financial distress where they may need to exit. We're able to help them do that. And we have all of the data from the wells as it flows to our facility. So it allows us to take a look at wells, know how they perform and assess the reserves of the well because we know the production levels from the well, we know the pressures from the well. When these opportunities arise, we execute on that and add to our production that flows into our operating facilities. I believe there'll be more of these things to come. It's hard to quantify how many and when and how. But if you're in the game, you're able to pick up opportunities that pay out in 6 months and have 150% rate of return. And when people want to move their capital from some of these things to an onshore business, somewhere, we may help them do that. And so we're always out for these things. We do operate and have been a longtime operator of key facilities and allows us the unique ability to bring in wells that we understand into our situation, take on their abandonment liabilities, in some cases. And for a small amount of cost, we can pick these wells up and make a lot of money.

Operator

And our next question comes from the line of Roger Read with Wells Fargo.

Roger David Read  -  Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst

The last question kind of took what I was going to ask which is, what are the returns on the tiebacks? But maybe if we could dig into that and think about the entry into Mexico with the exploration supporting in the short term or the next couple of years, let's say, the tiebacks. When you look at your overall offshore, what kind of returns do you want to achieve in this environment, do you think are achievable in this environment? I'm going to say 150% is a one-off as opposed to the norm there.

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

I'm sorry, the 150%, what was that regarding?

Roger David Read  -  Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst

You mentioned the 150% rate of return on the tieback.

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

That's a very unique situation where you're able to pick up something for sale and make an enormous return. It does show what our company can do and the uniqueness of our strategy and allows us to have those type of returns. It's -- in the tieback game in the Gulf today, it's easy to achieve full cycle 25% rate of returns at these prices quite easily. These things have -- if you want to talk about things, and of course, oil prices have improved. And over the last couple of years, there was this big push about talking about breakeven prices for things to achieve 10% rate of return. I hope that we're beyond that now, but we're talking about in the low-30s here now because the costs are incredible, incredibly low. So one regime cost going up, one regime cost going down. And so that's some solid business. And one thing I think is key to point out is the offshore business is a full cycle
business by definition. It always has been. You lease. You drill the well and produce tieback, et cetera. And when I say these midlife, these mid-20% to 30% rates of return, they're automatically full cycle, not high cycle, not without land, not with the long period of time. So I think it's good business and the costs are very good. The opportunities are very good. And that we're interested in participating in those, and we are.

Roger David Read - Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst

Okay. Great. And then moving to the Permian, a pretty good explanation, as usual, of what you're doing in the Eagle Ford and up in Canada. Thinking about 70% spending off on the onshore out of a relatively stable CapEx number, what is the Permian spending coming at the expense of? Or should I think of maybe $1.2 billion versus $1 billion, and so okay, that's my improvement or that's my incremental dollar in 2018, maybe 2019?

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

Well, I mean, we have situations we've entered into our onshore business. We're going to have capital allocated to the Duvernay next year due to an agreement we have there. And the wells are all performing above the curve there. And we want to invest capital there, and we are. And it kind of backs into what we have in Eagle Ford. And of course, in Eagle Ford, we've done very well there, maintaining production there for a low level of CapEx for a couple of years, but they could be opportunities where 8 wells or 2 pads of wells are drilled in an area to protect acreage. They may not be our top tier, and we want to -- but we want to move those 8 wells into Permian after we get these wells results. And we're very pleased with nearby results after we started leasing there. We started leasing in mid-16. And since all the issues with better clusters, better entry points, better core results, better sand propellant loading, different mesh on sand, those results got better and better. And this will be a matter of testing that and then we will move out of some acreage in Eagle Ford and put it into that area is how we're going to handle that at this time until we get further into our required completion -- drilling and completion spend in the Duvernay. And we'll assess among these 3 plays in the next 2 years or so what is the absolute best place to allocate all the capital. We're going to do very well when we do that.

Roger David Read - Wells Fargo Securities, LLC, Research Division - MD & Senior Equity Research Analyst

Okay. And then changing gears. With the news of a potential corporate tax rate policy, and I know energy taxes are a lot different with a lot of other taxes, is there any expectation that there could be an impact on kind of the overall deferred tax here or any sort of a tax asset that might not have value going forward in a lower corporate tax rate environment?

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

I'll let John answer that. Our phones are blowing up with texts from our Arkansas delegation at the moment on this matter.

John W. Eckart - Murphy Oil Corporation - Executive VP & CFO

Roger, this is John. And as you probably know, we do have deferred tax assets, net deferred tax assets in the United States. We have assets and liabilities. I mean, overall, we have net deferred tax assets. So on Day 1, should the tax rates go down to 20%, let's say, you'd have an impact on our deferred tax assets by reducing the overall deferred tax here or any sort of a tax asset that might not have value going forward in a lower corporate tax rate environment?

Operator

And our next question comes from the line of Arun Jayaram with JPMorgan.
Arun Jayaram - JP Morgan Chase & Co, Research Division - Senior Equity Research Analyst

First question, as you think about 2018, Roger, obviously, you announced the entry into the Permian and it sounded like capital allocation will depend on what you see in terms of your initial results, but are you ready yet to put out some preliminary thoughts on 28 (sic) [2018] production? You gave us a capital number of maybe something close to $1 billion or so. Any thoughts around ‘18 that you can provide at this time?

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

We really prefer to get into that on our call at the end of January. It's been the way we've done that. But obviously, oil price is a little bit higher, production higher, CapEx a little bit higher would be the best way to describe it.

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

All right. Fair enough. And my second question. In terms of the overall portfolio, clearly, Roger, you have a very diversified portfolio. By our count, you're now in 10 to 11 different areas, perhaps the most amongst the independents that we look at. And you probably can guess my next question is, how do you think about this from a standpoint of, given your size, of efficiently allocating your capital and your resources and thoughts about maybe pruning the portfolio to have maybe a few more -- a fewer number of focus areas?

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

Well, that's been our game for a while for a long, long time. It's kind of a misnomer about our company in how that works. I mean, the Houston exploration office is running the Mexico exploration, Brazilian exploration with one team and the Gulf of Mexico with one team, one floor of personnel. So it makes no difference to us where the big stratigraphic plays are, Upper Cretaceous or Upper Miocene zones, we're able to manage that with our team there. Our exploration team in -- headed out of Kuala Lumpur, our other major office in our company, runs on that side of the world without incredibly high cost and without much difficulty. And we are in offshore. So because of our diversity, number one, we make a lot of margin from our business. And because we are focused on costs, we make a lot of margin less costs there and have a real high adjusted EBITDAX number when we're moving items like ForEx and tax issues and things of that nature. So we do very well on that. We do very well when things change around the world and able to pick up on Brent or LLS. And we do very well on differentials because we're in a diverse business. And we've been in a diverse business for a long time. The exploration entries you're talking about for Mexico and Brazil, let's add those together. Over a 3-, 4-year period, all seismic, all back costs, everything you can do to drill 2 prospects, an all-in cost of the equivalent of around 9 Eagle Ford wells, we can go into this massive amount of resources that would be double our -- on our share basis, double our current proven. And so this is why we do this. We've been very, very successful in Malaysia doing this. Our offshore businesses are continuing to drive incredibly high full cycle returns going back in its history. So remaining in that business. And our onshore business is a nice onshore business with very low LOE compared to others, a growing profile, doing all the right things with capital allocation, technology and efficiency. And I just -- we're going to remain at this area and adding on Brazil at 20% working interest run out of our Houston office with a major operator like ExxonMobil is not difficult to do.

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

Great. If I could sneak in one more, Roger. One of the concerns in the marketplace is a bit around weaker AECO prices. You commented in your release around being able to navigate that through some marketing agreements. Can you just maybe elaborate on that and the ability of the Tupper to compete in a lower gas price environment?

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

Well, number one, Tupper is one of the best assets in the company, has some of the best go-forward economics. You can imagine our high cycle economics on these wells is really only $1.50 C AECO and our full cycle is $2. And we still, just looking at even the spots, like the spots of just a
couple of weeks ago, which are much higher now is near $2.20. So continue to see real, long-term AECO pricing above our prices we need. And we believe over time, you got to keep in mind, we’re going to be here for many, many, many decades producing gas here. And we feel good about our diversification we have both through hedging and getting off these other markets to give us, again, what Murphy always has is not every egg in one basket. We have diversity in our marketing. And if you look at a few days ago, on a USD basis, keep in mind, we speak of C AECO and occasionally on a USD basis, just keep it USD, the spot was around $1.70, yielding prices around $1.45 in Canada, gets to then between Emerson and Dawn, Chicago and Malin around $1.70 to $1.80. So we have 5 different places to market into plus our hedging. And that’s how we’re thinking about lowering our risk around different diversified areas. And I think it’s evidenced by the fact that we had a real good quarter where AECO was incredibly volatile due to some TCPL shut-ins and various things that happened. We’re really unscathed on that due to our long-term planning of our marketing team and focusing on the right things to make returns in our business.

Operator
(Operator Instructions) Our next question comes from the line of Muhammed Ghulam with Raymond James.

Muhammad Ghulam
So after the Midland Basin announcement yesterday, are there any plans to increase acreage in the basin in the future? And would you guys consider expanding into the Delaware as a central platform in the future?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director
I guess you never say never. 1.5 years ago, I didn't think I'll be here. So we're happy with what we have. We're happy with -- again, we’re always $2,000 an acre in the Eagle Ford, $2,000/acre in Montney and Duvernay, and now sub-$2,000/acres again. We go in with a different trade perspective. It’s documented in our long-term strategy. Take a look at these plays, can we improve what we see? We started leasing in there and happy with what we have there today. When -- we actually worked a lot on knowledge by attending a lot of data rooms, doing this for the last 3 years, but the incredible bid-ask spread was never appropriate. And we, at Murphy, have a differentiated view of how we can get in and prosper the way we like to work. And we came up with this entry and executing on that. But today, we’re not a -- into the high $1 per foot entry into these plays that require probably $55 oil to break even at least on a full cycle basis.

Muhammad Ghulam
So moving down to South America. Similar question, any plans to participate in the ANP auctions that are planned over the next 2 years? Or any plans to pursue further farm-in agreements like you had this quarter?

Roger W. Jenkins - Murphy Oil Corporation - CEO, President & Director
We will be looking to do so, but only at these working interest with the appropriate partners that have the appropriate experience and appropriate ability. One of our key co-venturers here was into the country in a very, very big way in the last couple of months, massive on capital allocation into Brazil. If there’s an opportunity at this working level with super majors, we’ll be doing that on exploration basis. And we do look at discovered resource opportunities there, which we can add value due to our expertise at operating offshore. That is still our primary focus. However, that has gone slower in the Petrobras approval cycle than we desire. And then we have been focused on working with Petrobras on the very successful fields next to these blocks, then it became an opportunity to farm into the blocks that tie very near -- we’re only 10 miles away from major fields discovered by Petrobras there with very similar geologic setting, pressures, depths and oil sourcing. So decided to enter in there again because it’s very inexpensive bang for the buck situation with a very successful partner group. And that’s our focus. And that’s why we executed on it.
Operator

And I’m showing no further questions at this time. So with that, I’d like to turn the call back over to President and CEO, Mr. Roger Jenkins, for closing remarks.

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

Thanks, everyone, for calling in today. We’ll see you in the new year. And everyone, take care and thank you.

Operator

Ladies and gentlemen, thank you for participating in today’s conference. This does conclude the program, and you may all disconnect. Everyone, have a wonderful day.