Operator

Welcome to Kosmos Energy's fourth quarter 2016 conference call. Just a reminder, today's call is being recorded. At this time, let me turn the call over to Andy Inglis, Vice President of Finance and Treasurer at Kosmos Energy.

Neal Shah

Thank you, operator and thanks to all of you for joining us today. This morning, we issued our fourth quarter earnings release which is available on the investors page of the kosmosenergy.com website. We have also published a presentation this morning that we plan to refer to during today's call which is also available on our website. We anticipate filing our 10-K for 2016 with the SEC later today. Joining me on the call today are Andy Inglis, Chairman and Chief Executive Officer; Brian Maxted, Chief Exploration Officer; and Tom Chambers, Chief Financial Officer.

Before we get started, I'd like to mention that this conference call includes certain forward-looking statements based on our current expectations. The risks associated with the forward-looking statements have been outlined in the earnings release and in our SEC filings.

We may also refer to certain the non-GAAP financial measures in our discussion. Management believes such measures are important in looking at the Company's historical and future performance; and these are commonly referred-to industry metrics. These measures are provided in addition to and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP and included in our SEC filings.

At this time I will turn the call over to Andy.

Andy Inglis

Thanks, Neal and good morning, everyone. Amid a challenging macro environment, 2016 was a successful year for Kosmos. We accomplished all of our key objectives because we entered the downturn in a strong financial position and stayed disciplined in the execution of our strategy. This financial strength and business discipline is what differentiates Kosmos from other exploration companies and ultimately enabled the successful farm-out of our Mauritania and Senegal assets.

Before we discuss the benefits of the BP farm-out, I would like to begin by highlighting our achievements in 2016. In Ghana, we effectively managed the Jubilee turret issue identified early last year, the impact of which is largely cash flow neutral as a result of the insurance coverages we have in place. The TEN fields began oil production on schedule in August. With TEN online, we became free cash flow positive in the fourth quarter through the combination of increasing production and decreasing CapEx, a trend we expect to continue in 2017.

In Mauritania/Senegal, we completed appraisal drilling of the Tortue discovery and successfully drilled the Teranga exploration well in Senegal. To date, we've discovered a gross Pmean resource, approximately 25 trillion cubic feet of natural gas and de-risked at least an additional 25 trillion cubic feet of gas along the inboard trend.

In the basin as a whole, we've now defined resource potential in more than 25 billion barrels of oil equivalent which could make this basin comparable in scale to Mozambique but with liquids potential. [Indiscernible] during the drilling continues to support our charge model which predicts the presence of liquids in the outboard part of our acreage. During the farm-out process, several super majors peer-reviewed our work and came to the same conclusions, supporting our view of the basin's quality and potential.

In the exploration portfolio outside of Mauritania and Senegal, we’re maturing opportunities with the focus on de-risked, proven oil provinces. In Suriname's Block 42 we farmed out to Hess, who were involved in the Liza discovery offshore Guyana and bring significant regional technical knowledge which should assist in our exploration and drilling program expected to begin in 2018.

Across our Sao Tome acreage, we have partnered with Galp to provide important relationships and aboveground capability ahead of drilling.

I will now turn to the impact of the BP transaction which marks a turning point for the Company. Last week we announced the completion of the transaction in Senegal following completion in Mauritania in early January. The Kosmos/BP partnership in Mauritania and Senegal combines the expertise of two world-class companies. Kosmos brings an industry-leading record of successful deepwater exploration to the partnership, while BP brings deepwater development experience as well as LNG production and marketing expertise. Importantly, both companies are strategically aligned on the vision for the forward exploration plan in the Tortue gas project.

The BP deal is important to Kosmos for several reasons. First, it demonstrates that our strategy is working. Since Kosmos was formed in 2003, the industry has undergone considerable change. But the one thing that remains the same is our unwavering commitment to our strategy, growing the business organically through successful frontier exploration and commercialization of our discoveries.

This strategy remains as relevant today as ever. The best assets in both the onshore and offshore will continue to attract capital and deliver returns. The fixed consideration alone represents a minimum 2.5 times return on invested capital in approximately 2 years. But we believe the real value lies in our 30% retained interest which could be maximized under this long term partnership. Second, the partnership with BP accelerates an exploration program in 2017 and 2018 that offers perhaps the largest organic growth opportunity on a relative basis in the industry. And their work is fully carried under our deal with BP.

The chart on slide 3 shows the 2017 and 2018 global deepwater drill-out by company, based on independent third-party data from Richmond Energy Partners. According to this data, Kosmos alone is testing the fourth most resource potential on a net basis over 2017 and 2018. To put this in context, the only companies that are testing more net resource are super majors and our net resource to be tested is more than 37 other explorers combined.

Slide 4 shows the exploration potential to be tested on a relative basis for companies with less than $40 billion in market cap. As you can see, the potential impact of this high-grade exploration program result in Kosmos testing net resource more than 2 times any E&P company less than $40 billion in market cap. Each of these high-quality prospects has the potential to significantly impact the future of the Company. And we plan to resume drilling next quarter which is why we're so excited about the exploration program.

Third, the transaction defines a clear path to production diversification for Kosmos through the Tortue development. Our primary reason for partnering with BP is their strategic alignment on the pace of development. With Tortue targeting first gas in 2021, Kosmos expects to have a third world-class asset generating substantial cash flow which will bring significant benefit to both countries as well. Lastly, the transaction enhances our already strong financial position, ensuring that we have the financial capability to commercialize future discoveries. As a result of the terms we agreed, our portion of exploration, appraisal and development costs are expected to be largely carried over the next several years in Mauritania and Senegal. So despite a robust activity set, we’re one of the few E&Ps generating significant free cash flow at $50 a barrel.

I'll now cover these last two points in more detail before turning the call over to Brian, who will discuss our exploration program in greater depth. As I mentioned, one of the primary rationales for partnering with BP is their strategic alignment with our vision of delivering early revenue in Tortue, reaching FID in 2018 and first gas in 2021. We're moving forward on the near-shore FLNG concept that Kosmos previously developed which can deliver a breakeven of less than $5 per MCF. In addition to being one of the lowest-cost LNG projects globally, this scheme accelerates first gas and offers the opportunity to scale up quickly as demand for LNG grows.

In just over two months in signing the deal, work across all dimensions of the project has accelerated considerably and the transition with BP is going very well. Given the importance of the project to BP, they already have approximately 75 people working on the project. With the right organizational capability in place, the partnership is focused on reaching several key milestones in 2017 through a full activity set, shown on slide 5, that should enable a final investment decision in 2018.

In the first quarter of this year, the partnership is focused on completing the conceptual engineering that will underpin our nearshore development. We're continuing to evaluate industry FLNG solutions for the midstream infrastructure and expect a decision to be made during the second quarter. Also during the second quarter, after drilling our initial exploration well in the outboard, we plan to construct a drill sand test on the Tortue to confirm our view of reservoir connectivity, well deliverability and gas composition.

Following the DST, we expect to begin the front-end engineering and design or FEED, process in the third quarter. The other main items we're working in parallel for sanction are the signing of the intergovernmental corporation agreement or ICA which will be followed by the unitization agreement in gas marketing. We expect the ICA to be signed before major capital spending begins, starting with FEED.

On the gas marketing side, we're in ongoing discussion with both BP, who has offered to buy the gas, as well as other parties. And I expect these discussions to be included before we reach FID. Given the size of the first phase, the low-cost basins and the demand we've seen to date, we do not see this as an impediment to FID, unlike many other LNG projects.

So in summary, we have a simple aligned partnership that's working well. And we're proceeding with a 2017 activity set that supports the delivery of a cost-competitive project on an industry-leading timeline.

At this time, I will transition to discussing our strong financial position and robust liquidity which are fundamentally underpinned by our Ghana assets. As a result of growing Ghana production in our BP farm-out, we plan to deliver free cash flow of approximately $250 million in 2017 at $50 per barrel which is unique compared to many of our peers. At Jubilee, revised operating procedures are working and our insurance coverage continues to mitigate any financial impact. The FPSO turret remediation work is progressing and the vessel is expected to be spread more than its current heading within the next few days. It should allow the tugboats currently required to hold the vessel on a fixed heading to be removed, simplifying operations and decreasing cost.

In the second phase the partnership is continuing to evaluate options to select the optimal long term orientation of the vessel and discussions are ongoing within the partnership to optimize any shutdown. We believe these assets will lead to a significant reduction in duration of the shutdown in 2017. Even with the remediation work ongoing, field performance has been strong with recent metered production around 120,000 barrels of oil per day, after the Jubilee partnership procured a second dynamically positioned shuttle tanker for increased offloading efficiency.

On TEN, after achieving first oil in August 2016, our oil production and water injection systems have been commissioned. And commissioning of the gas compression and injection systems are ongoing. Earlier this year, the capacity of the FPSO was successfully tested at an average rate of over 80,000 barrels of oil per day during a 24-hour flow test. Production testing and initial results on the 11 wells at TEN suggest 2P reserve estimates both the Ntomme and Enyenra fields are in line with previously guided expectations of around 250 million barrels gross. And, indeed, the primary driver of our reserve replacement was receiving additional 1P reserve credit at TEN.

Due to certain issues with managing pressure in the Enyenra reservoir, because no new wells can be drilled until after the previously disclosed ITLOS ruling, the operator has elected to manage the existing wells in a conservative manner. However, the partnership is currently evaluating ways to increase oil production during the year and ITLOS' ruling is now expected around the end of September, after which we plan to resume drilling and increase field production.

I will now turn the call over to Brian to discuss our upcoming exploration program. Brian?

Brian Maxted

Thanks Andy. Our primary objective this year is to deliver a company-making ALLL and/or liquids-rich gas discovery. In my commentary this morning, I'd like to discuss in more detail the drivers behind our exploration program and the specifics around the exploration targets in our upcoming drilling program in both Mauritania and Senegal. After this, I will conclude with a short update on Suriname.

However, before proceeding further, I would like to take a moment to briefly add my exploration perspective to Andy's opening comments. The clarity of our exploration plan, the quality of our process, the capability of our people and our discipline in execution, including patience, persistence and performance over the last several years, is now paying off. Since we formed the Company 13 years ago, we've played a key role in unlocking two of the three Cretaceous petroleum systems which have been opened by the industry in our geography, the South Atlantic margin. And now we have carefully assembled a new, large, high-graded exploration portfolio which includes a strategic presence in both of the current proven cretaceous exploration hotspots at Mauritania/Senegal and Guyana/Suriname, as well as positions us to open up the next space.

Our position as a leading global deepwater explorer is underpinned by the size and quality of the prospects we're drilling over the course of the next couple of years. In aggregate, the prospects to be drilled amount to over 15 billion barrels of oil equivalent of gross unrisked potential. They include some of the largest prospects to be drilled by the industry anywhere in the world during this time. Now let me turn to the drivers behind our second-phase exploration drilling program in Mauritania and Senegal. As you will see shortly, this independent oil well program is scheduled to start next quarter and continue into 2018. And we will utilize the remaining time on the current Atwood Achiever contract. Final sequencing may be optimized and is subject to final approvals.

As you know, the first exploration drilling phase, through 2015 and into early 2016, tested the inboard sloped channel trend of the Senegal River and made three gas finds, including Tortue, Marsouin and Teranga. Since this time, our technical focus has been firstly integrating the newly available information; and, in particular, the well results and sample analysis to refine our charge model.

This is designed to both reconcile well outcomes and observations, as well as also provide us with a predictive tool going forward as we begin our second phase of explorations. Alongside our calibrated AVO capability, this should enable us to better predict hydrocarbon phase as well as presence.

Slide 6 of the presentation summarizes our current charge model which is the key driver for the ranking of prospects. The map image on the right of the slide summarizes the Cretaceous petroleum system that includes, in particular, consolidated, common-risk segments that depict the likelihood of encountering oil or liquids with the condensate gas ratio greater than the economic minimum of 50 barrels per million standard cubic feet. The darker green indicates a higher chance of liquids. The key takeaways is that based on this current chart model, we consider that there is a good chance that we will be able to find liquid or liquids-rich gas in the upcoming exploration drilling campaign.

The model continues to contemplate three key source rocks. These include, from oldest to youngest, a deeper, regionally dominant source which we have previously referred to as the Apto-Barremian, but we now interpret to be Neocomian and Valanginian; and then the shallower Albian and Cenomanian-Turonian sources. Although sensitive to a number of assumptions, the work we have undertaken suggests, on the basis of these three oil source systems, that it is the interplay of five principal processes which determines the distribution of hydrocarbon fade. Furthermore, it is the different interplay in different areas between these processes which makes each of our prospects independent.

While time does not allow us to discuss the controls and consequences of each in detail, the five processes are, one, source presence and facies; two, overpressure; three, the timing of hydrocarbon generation and ultimate maturity; four, the fractionation of fluid during vertical migration; as well as the fifth which involves either the mixing of hydrocarbons from the deepest source with or direct charging from -- of reservoirs from those oil- and liquids-rich hydrocarbons generated by the two shallower sources.

The charge model explains that the lean gas found to date along the in-board slope channel trend is a function of a number of factors related to the deeper charge system from which it is sourced. These include source facies dilution, i.e., more gas prone due to the presence of the Senegal River depocenter; the generation and late cracking of gas due to its deep burial and high maturity; substantial amounts of overpressure which caused extended vertical migration through breaching of multiple sealed reservoir pairs leading to a fractionation or drying of gas; and no oil-limited enrichment of fluids with oil or liquids, given the immaturity of the shallow source on this trend.

Similarly, the model explains that the presence of oil along the basin and flanks, both to the north in Mauritania and south in Senegal, is related to a combination of the presence of the two oil-prone along with the shore younger source rocks and limited exposures to the deeper source rock.

Not surprisingly, therefore, the model suggests that, firstly, for the same reasons, the best chance of finding oil and/or liquids-rich gas is in Northern Mauritania with the risk also decreasing south as we go into Senegal. The model also suggests that we will have a moderate to good chance, of 1 in 3 to 2 in 3, of finding oil or liquid-rich gas along the outboard flanks of the Senegal and Nouakchott River depositional systems in the base of both fan fairways.

This is due to the perceived presence of more oil-prone and oil-mature facies in the deeper Neocomian to Valanginian source, related to a more marine depositional environment and less oil facies dilution by the river depocenters as well as the shallower depth of burial, respectively. Also important is the likelihood of less fractionation due to reduced vertical separation between the source rocks and the overlying Cenomanian and Albian reservoirs.

So to summarize, we have done a lot of work on the charge over the last nine months and now feel we have a tool which indicates that the likelihood of finding significant oil and liquids on our blocks is actually quite good.

Secondly, alongside this charge work, we're fully defining and maturing the key prospects on each of the four independent basin floor fan fairways. In this regard, once ongoing operations are complete, we will have acquired over 30,000 square kilometers of 3D seismic offshore Mauritania and Senegal.

In Senegal, processing of the outboard survey acquired in early 2016 is sufficiently advanced to fully define the Yakaar prospect, formerly referred to as Teranga West and select a well location to test it. The Yakaar prospect in Northern Senegal is shown on slide 7 and this will be drilled first, in the second quarter of this year.

This base of slope fan is 40 kilometers west and 500 meters downdip of the

Teranga discovery. This is a low-risk, approximately 15 Tcfe prospect located on the southwest flank of the Senegal River depocenter. It comprises stacked, amalgamated Cenomanian clastic reservoirs in a combination structural stratigraphic trend charged from the deeper oil-prone, oil-mature Neocomian to Valanginian source segment. It has strong, calibrated AVO support which displays excellent reservoir trap conformance.

Importantly from a charge point of view, this location is both closer to the deeper source and has access to the younger Albian source which we know from Teranga 1 is oil-mature in this region. The interaction of these two source rocks and the timing of generation will be key to determining a liquid content in this well.

As I previously mentioned, we believe the liquids economic cut-off is a CGR of approximately 50 barrels per million cubic feet. So our 15 Tcf discovery with the 50 CGR would yield a 750 million barrel liquid discovery. At 100 barrels per million cubic feet, it would yield 1.5 billion barrels. Following the first well, as presently scheduled, the drill ship will then undertake a drill stem test on Tortue, after which we plan to move to the Requin prospect in southern Mauritania in the third quarter, as shown on slide 8.

The prospect is well imaged on current 2D seismic at the present time. And the drilling location will be selected after analyzing the recently completed 3D. Requin is a 5 to 10 Tcfe prospect with a liquid component of between 250 million and 1 billion barrels of oil [Technical Difficulty] liquids. It is located further inboard than the other prospects on the west flank of the Senegal River depocenter, approximately 30 kilometers northwest of the Tortue discovery. It comprises, again, an amalgamated Cenomanian and Albian clastic reservoirs in a combination track with a major structural component, charged from the deeper Neocomian to Valanginian source system. It again displays strong calibrated AVO support for the presence of hydrocarbons.

Following Requin, we plan to move to the Lamantin prospect in the fourth quarter. On slide 9, you can see more information on the Lamantin prospect, located approximately 150 kilometers northwest of the Chinguetti oilfield in northern Mauritania.

Lamantin, we judge, is a 2 billion to 3 billion barrel oil equivalent prospect. It is also base of slope fan and comprises stacked amalgamated Campanian clastic reservoirs in a combination trap, charged from the adjacent and underlying CT and Albian oil-prone, oil-mature source systems. The prospect is well-defined on 2D at the present time, with good AVO support and conformance to the reservoir and the track. In our experience, we expect the prospect's definition to only improve with the addition of new 3D seismic. Also, given Lamantin lies in the heart of the proven CT and Albian source kitchens, this is our lowest-risk black oil prospect.

Lastly, Requin Tigre, a prospect in Senegal, is shown on slide 10. This very large, base of slope fan is approximately 40 kilometers from the Tortue discovery. It is a 60 Tcfe prospect with a liquid component between 3 billion and 6 billion barrels. Requin Tigre Is located in the West Bank of the Senegal River depocenter and comprises stacked, amalgamated Cenomanian and underlying Albian clastic reservoirs in a combination structural stratigraphic trap; charged, again, from the deeper, more oil-prone, oil-mature Neocomian to Valanginian source segment.

As with the other prospects, Requin Tigre displays strong calibrated AVO support with excellent reservoir/trap conformance on the new seismic which we have acquired over the prospect. We're currently working on selecting an optimal drilling location. But given the scale of the prospect and the presence of multiple reservoir targets, additional seismic processing time is required. We therefore expect this well to spud last in our four-well sequence towards the end of the year.

As I mentioned, these four independent prospects are some of the largest and most anticipated prospects to be drilled by the industry in recent memory. And we're very excited to begin this second phase of exploration drilling, offshore Mauritania and Senegal.

Lastly, turning to Suriname on slide 11, here we have completed a large 3D seismic survey of the Block 42 and a portion of Block 45 and processing interpretation is now ongoing. Encouragingly, the multi-billion-barrel potential originally identified on regional 2D seismic appears to be confirmed on the new 3D seismic. We have the already defined and ready-to-drill Anapai prospect in Block 45 that's highlighted on the seismic image.

In addition, a combination structural stratigraphic track such as Aurora which involve top-of-Cretaceous reservoirs charged from CT and/or Albian source rocks, are visible in Block 42. These are along trend of and on the same play fairway as the basin opening in commercial Liza find, as well as the Payara discovery recently made in the adjacent Stabroek Block in Guyana. Very early production with the new 3D seismic are extremely, encouraging and we anticipate evaluating, maturing and ranking these prospects as well as selecting and renting a well to drill next year, subject to partner alignment.

So to summarize, from an exploration standpoint, this Company has not been better positioned for organic value growth through the drill bit since 2007, the year we found the Jubilee field with the Mahogany 1 well in Tano Basin in offshore Ghana. We have a proven, differentiated exploration strategy. We have a truly world-class exploration portfolio. And we're on the cusp of commencing a transformational, multi-well, multi-year, high-impact exploration drilling program.

I will now turn the call over to Tom to discuss our financial results and guidance for 2017.

Tom Chambers

Thanks, Brian. At the end of the fourth quarter, Kosmos had total corporate liquidity of over $1.2 billion as we became free cash flow positive with the delivery of the TEN field. This includes $617 million of undrawn availability on our reserve based lending facility or RBL; $400 million of undrawn availability on our revolving credit facility; and $194 million of available cash. So we entered 2017 with a strong balance sheet and liquidity position. And as Andy mentioned, we expect to generate approximately $250 million in free cash flow at $50 oil this year.

We expect to use that free cash flow to pay down a portion of the borrowings on our RBL and create additional headroom to further fund exploration success and continue our strong organic growth. In fact, this year we have already received $162 million in cash proceeds from the closing of the BP farm-out in Mauritania; and expect to receive approximately $60 million in further consideration in the first quarter from the closing of the Senegal transaction. As a result, we plan to repay $150 million under our RBL during the first quarter.

So now I will turn to the results for the quarter and the full year. We finished the year with seven crude oil liftings, three of which occurred in the fourth quarter, in line with our revised guidance issued on the third quarter conference call. This generated full-year 2016 oil revenues of $310 million, excluding $188 million of derivative settlements. When you add our revenue to our settled hedges, it reflects a realized price of approximately $73.76 per barrel in 2016.

Full-year revenues were down compared to 2015 as a result of lower realized oil prices, as well as downtime and reduced production related to the Jubilee turret bearing issue. LOPI insurance proceeds of $75 million through November of 2016 partially mitigated the revenue loss compared to the prior year. As of 2016 year-end, Kosmos has net approved claims of $91 million against our LOPI and H&M policies with $87 million of cash received to date which demonstrates that the process is working well with our insurance companies.

For 2016 we generated a net loss of $284 million or $0.74 per diluted share and in the fourth quarter generated a net loss of $57 million or $0.15 per diluted share. Adjusting for the impact of one-time items that affect comparability, the Company generated a net loss of $100 million or $0.26 per diluted share for the full year of 2016 and a net loss of $6 million or $0.01 per diluted share in the fourth quarter.

On the cost side, operating expense for the fourth quarter was $44 million or $14.75 per barrel versus $30 million or $10.50 per barrel in the fourth quarter of 2015. For the quarter, this included approximately $47 million of regular operating expense and $8 million associated with the revised operating procedures, offset by $12 million in insurance recoveries. The fourth quarter included a full quarter of TEN operating expense which is higher than Jubilee as a result of the fact that the FPSO is leased and the lease cost is included in operating expense.

Exploration expense of $76 million for the fourth quarter included approximately $44 million of costs associated with the stacking of the Atwood Achiever; as well as $31 million in seismic, geologic and geophysical costs primarily related to Mauritania and Senegal. This resulted in full-year 2016 exploration expense of $202 million.

General and administrative expenses were $28 million during the fourth quarter, an 8% decrease compared to the same period in 2015. Full-year general and administrative expenses of $88 million were down 36% from 2015 expense of $137 million, the result of proactive cost management and reduced equity-based compensation expense.

Depletion and depreciation expense for the quarter was $74 million or $25.08 per barrel. This was an increase from the $15.98 per barrel in the fourth quarter of 2015, primarily attributable to realizing the first TEN lifting which has a higher depletion rate than Jubilee and drove the blended rate higher, a trend that should continue into 2017.

Taxes decreased in 2016, largely as a result of lower oil pricing. It is important to note that our deferred taxes fluctuated over the year, based on mark-to-market value of the hedges, making it very difficult to predict our overall tax position. This will again be the case going forward in 2017.

We continue to maintain our strong hedge position and currently our oil hedges total approximately 11 million barrels, with approximately 7 million barrels hedged in 2017 and 4 million barrels hedged in 2018. Our 2017 hedging program reduces commodity price exposure for approximately 65% of 2017 production, with average floor prices of approximately $59 per barrel of Brent. The Company's robust hedging program remains a key component of our strategy to protect our cash flows, balance sheet and liquidity.

At this time, I'd like to transition to our expectations for 2017. During 2017 we anticipate selling 11 cargos, net, to Kosmos, including eight cargos from Jubilee and three from TEN. This lifting schedule reflects our view of a significant reduction in required field downtime for the second phase of the Jubilee FPSO turret remediation work. For TEN, we expect three cargoes in 2017, one per quarter, starting in the second quarter which is consistent with operator gross production guidance for the year.

Also on the revenue side, we anticipate receiving LOPI proceeds of approximately $70 million during the first half of 2017, including approximately $50 million of proceeds in the first quarter based on our current production forecasts.

On the cost side, we anticipate total production operating expense for 2017 to average approximately $18.50 per barrel which includes both Jubilee and TEN as well as the revised operating procedures at Jubilee. Including the impact of anticipated insurance reimbursements for Jubilee, we expect total operating expense to average approximately $15 per barrel in 2017.

G&A costs for 2017 are expected to be approximately $100 million with approximately 55% cash-based and 45% allocated to non-cash, stock-based compensation expense. We expect that DD&A should average around $25 per barrel as we depreciate more TEN barrels which have a higher per-barrel cost and move the blended rate higher.

Exploration expense during the first quarter is expected to include approximately $100 million of costs related to the warm stacking of the Atwood Achiever and the cancellation of our rig extension. On a regular quarterly basis, we expect to have approximately $25 million per quarter of ongoing non-dry hole exploration expense related to seismic and geophysical and geological work. During the year, we also expect net interest expense to increase; the result of less interest capitalization, after TEN commenced production last year.

Bearing in mind the challenge of giving guidance on taxes, assuming Brent remains at $50 per barrel, we anticipate cash taxes will be higher than 2016 levels while the deferred component will vary, driven by the mark-to-market position of our hedges. Overall, we expect taxes to be approximately $6 per barrel on average for 2017, assuming a $50 Brent price deck, of which approximately 60% is current. This excludes any deferred taxes associated with the mark-to-market position of our hedges.

With regard to our $175 million capital program, as we described earlier this year, $75 million is earmarked for Ghana, the majority of which will be spent on Jubilee. And $100 million is earmarked for planned exploration activities including new ventures, seismic acquisition and geological and geophysical technical fees.

So, as we execute our strategy, we're committed to maintaining the strength of our balance sheet and creating value for our shareholders through the cycle. Kosmos remains in a strong financial position and we will continue to focus on the disciplined execution of our strategy, both from an operational and a capital allocation perspective.

So with that, that concludes our remarks. And now, operator, we would like to open up the call for questions.

Question-and-Answer Session

Operator

[Operator Instructions]. Our first question comes from the line of Brendan Warn with BMO Capital Markets. Please proceed with your question.

Brendan Warn

Just first question -- and I'll have a follow-up after it -- probably more to Brian. I appreciate a lot of new detail on slide 6 and 7. Could you just talk through for me, as an engineer, more putting a lot of this detail into, call it, probabilities of the geological chance of success for your first prospect that you've got award of on 3D seismic over? And then I'll leave it for a follow-up.

Brian Maxted

Yes, the geologic chance of success on Yakaar we consider to be a very, very high chance of success. It's a base of slope fan that's downdip; it's downdip off the Teranga discovery which, although it's 30 kilometers away, we see a good seismic continuity and therefore good calibration. So the AVO is calibrated. As you know, the AVO is not able to just, in itself, determine the difference between oil or liquids and gas.

So, depending on the deeper source rock to be, one, more in an oil facies as you come out of the main delta; and, two, being more oil mature; and, three, being closer to the Albian/Cenomanian reservoirs and therefore suffering less fractionation. The longer the distance -- and that's shown on those slides -- the distance below Teranga, as an example, is 3 kilometers from the [Technical Difficulty] to the reservoir. In Yakaar, it's just 2 kilometers which is less of a distance for fractionation and drying of the gas.

And then the final point is it's in an area that's got access to the mature, oil-prone Albian source rock that we saw in the deeper part of the Teranga 1 well which, as you may recall, had a gas condensate ratio of 167. And the Cenomanian had a gas condensate ratio of 30. So to get to 50 is not asking a lot. And the geological setup of the Yakaar prospect is quite different from Teranga which is why we believe that we've got a decent chance of finding oil -- or liquids and/or oil in Yakaar. And then with the AVO, we think it's a very low-risk prospect, in and of itself, in terms of the discovery of anything.

Brendan Warn

Are you willing to give your, call it, either your own personal view or your corporate view on the probability, firstly, of be it dry gas or a liquids-rich discovery, obviously being two different numbers? Having built up, having Albian as full disclosure --?

Brian Maxted

I think, look, if you look at the risk segments on the charge prediction map which suggests it's in that range -- 1 in 3, to 2 in 3 or slightly greater; 1 in 3, to 2 in 3 -- I think we feel good about that. That's a decent chance. I wouldn't go beyond what that suggests. But I think that 1 or 2 out of 3 chance of finding a commercial liquids discovery is as good as we can refine it, based on the model as it sits today which is not calibrated, outside of the slope trend and the oil discoveries to the north and south of us.

Brendan Warn

Okay. Then in follow-up, my question relates more to the free cash flows or cash flows. I appreciate the guidance you have given. At $50 a barrel, generation of $250 million, I just wonder what the sensitivity of that is for every, call it, additional $10 -- or what is it at $70 a barrel? Just for calibration of model.

Andy Inglis

Brendan, it's Andy. So for an additional $10, if you went from $50 to $60, it's around additional $75 million of free cash flow.

Operator

Our next question comes from the line of Ed Westlake with Credit Suisse. Please proceed with your question.

Ed Westlake

I guess this is more sort of a commercial question. Each of these prospects that you've identified, if you have the right gas/oil ratio, would clearly be large enough to develop. Maybe -- there is perhaps two questions here. Maybe on the first one, if, say, they do prove to be gassier, at what point does it make sense to go instead of with FLNG, but to move to like a full LNG development? That's the first question and then a follow-on.

Andy Inglis

Why don't I --? I'll take that. I think what's interesting to me is the competitive nature of FLNG versus an onshore scheme. We think today that the fundamentals of the way in which FLNG can be modularized, the way the capital spending can be matched to the growth of LNG demand, means that FLNG is actually competitive with a big onshore scheme.

So, I think, as you start to think about the commercial approach to it is fundamentally the way to move a gas project to ensure that it's the lowest-cost gas around and we have an FLNG scheme today which absolutely does that. I think we can expand that scheme from an initial phase of around 5 million tons to 10 million tons, Tortue growth.

If you had additional gas in the future discoveries, you could continue with the same approach which I believe will continue to be very cost competitive. And it allows you to take that modular approach to be able to build it to the future demand. So I don't think this is simply a question of offshore versus onshore. It's actually a question of what is the lowest-cost way of doing it. And I think today, I fundamentally believe the advances that are being made on FLNG -- it is a cost-competitive approach. And it may well be the enduring cost-competitive approach.

Ed Westlake

And then so you do get enough oil, I guess maybe 0.5 billion barrels, typically would support an FPSO. Any early idea of where you think the breakeven is? It may be very early to answer that. But obviously the prolific gas fields have low gas breakevens. I'm just wondering what your thoughts are, at this point, on the oil side.

Andy Inglis

Well, I think what we've said -- and again I think it's early days yet, so we need to be sort of careful about being too proscriptive. But we've looked at what we believe is an economic liquids yield at the current oil price. And we believe it's around $50 barrel -- 50-barrel CGR. So we believe, therefore, the liquids targets that we see in the prospects we've described are economic to develop in the current price environment.

Ed Westlake

Using the strip kind of price.

Andy Inglis

Using the strip kind of price of about $50 world. So we’re not -- look, I think you know -- and the point about all of that is you go back to -- it's a slide that we've shown you many times in the past. But Kosmos' strategy was always about targeting things that were economic and provided a healthy return in a $35 to $50 world. Nothing has changed. Why does it work? It's because entered early, good fiscal terms; and these are world-class prospects. If you put that together, it gives you efficiencies around the development scheme.

And I think that's a point that I really want to emphasize today is that Brian has showed you four world-class prospects. These are large; and, therefore, through scale, have natural development efficiencies. And I think that's the big driver behind what we see in this exploration program we're embarking on. These are very differentiated in terms of the scale and, therefore, the quality.

Operator

Our next question comes from the line of Anish Kapadia with Tudor Pickering. Please proceed with your question.

Anish Kapadia

A couple of questions from me, first of all, just looking at your stock price, where it's trading relative to when you did the deal, just really a few percent higher than back then. Just wondering are you thinking about essentially share buybacks, given the market is not appreciating the deal, the size of the exploration prospects you are seeing this year? Is that one area that you would consider over the course of this year?

Andy Inglis

I'm not in the mindset of share buybacks today. I think our fundamental belief is that we believe we're going to be successful with the exploration program. And therefore, our objective is to ensure that we're in a strong financial position to be able to follow up with the appraisal and development programs that would follow.

We believe, actually, very strongly that the value in the deal is in the 30% that we retained. And I think our strength as a Company comes from our ability to be able to have the financial firepower to be able to stick with that 30% and be able to capitalize on it fully. And so we're planning for success. We believe that we're going to be successful over this well program; and, therefore, having a balance sheet that allows us to pursue that success and not be compromised because we can't pay our way is critical.

So I don't anticipate share buybacks being the use of capital versus the opportunity to be able to invest in the success from the exploration program.

Anish Kapadia

Okay. And the second question, on Morocco -- I was wondering if you could give an update on your views on the Moroccan exploration acreage that you have and any update on the drilling carry with BP.

Andy Inglis

Yes. Brian will pick that question up.

Brian Maxted

In Morocco, we’re actually -- just last day or so -- started a new 3D seismic program off the Sahara, large 3D, nearly 10,000 square kilometers. And in the middle of the year we will be shooting another 3,000 or so in our Essaouira block, offshore Morocco census stricto. So we’re back after the initial drilling in Morocco and Sahara a couple years ago to shoot the seismic and pursue new ideas, principally in the outboard parts of those two fairways. And that's where we’re at the present time.

Anish Kapadia

And the drilling carry from BP, though, is still in place?

Andy Inglis

BP have exited Morocco. And in lieu of that exit, they provided us with a consideration to enable the exploration to continue there.

Anish Kapadia

And one quick follow-on, could you give what the cash flow impact would be if you did, in fact, have the full 12-week shutdown on Jubilee? What impact would that have on your current free cash flow guidance?

Andy Inglis

I think that the best way to look at that is to see it as a process where we now have the vessel spread moored and we have made a lot of progress on that. We believe it will be finished within the next three or four days. At that point, we're going to evaluate what is the right long term solution to the heading of the vessel.

We believe we’re in a position today where it's fundamentally about stepping back and ensuring that we do have the fatigue life that will give us the life-of-field. And there are several ways of doing that. And we need to come through with the right long term solution that enables us to deliver that outcome for both ourselves as a partnership and the government.

So I think it's too early to actually determine what the length of the shutdown is going to be. Tullow have clearly talked about a shutdown of up to 12 weeks. We've taken the view that it could be shorter. And I think within the two numbers, there would be a cash flow impact. But it's not significant, given the $250 million that we’re delivering.

Operator

Our next question comes from the line of Richard Tullis with Capital One Securities. Please proceed with your question.

Richard Tullis

Just looking at the exploration program set up over the next several quarters, Brian, still expecting something around 80 days to drill the first well?

Brian Maxted

Yes. We've historically said 2 to 3 months; and then in the kind of 60- to 90-day range. We expect these wells to be relatively straightforward. We've got pretty good control now, we believe, on the seismic in terms of both depth prediction and pressure prediction. So hopefully there won't be too many drilling issues, but in that range.

Richard Tullis

And lastly, looking at things more globally, we have been hearing a lot about rising costs from many of the shale operators over the last several weeks. And could you discuss current expected exploration development cost from the deepwater projects perspective? I imagine the global deepwater projects maybe don't see much of an increase at all or maybe nothing at all. Could you talk about things from that perspective?

Andy Inglis

Yes. I think, Richard, we’re actually in a different part of the cycle. I think we're actually in a cycle in the deepwater where we still have significant oversupply of capacity across all dimensions; whether it's deepwater drilling rigs, whether it's deepwater fabricators, seismic. So I think we’re in a very different world. And we have a world also where the cycle time is clearly different.

If you start to think about the current price environment we have been through, the cycle time of the big projects is typically three years, once you approve a project and once it gets into production. And so as we go through the current price cycle, all of those projects are, quote, now coming to an end; and therefore actually supply, the oversupply of capacity of the industry is growing currently rather than diminishing.

So I think we're actually still on a downward trend in terms of costs, rather than at a rising trend. And it has always been the same. It's about the cycle time of projects. The cycle time of the well that is, in a matter of days, in the lower 48 is very different from the multiyear projects that are occurring in the deepwater. So it's no surprise that I think we're still in a downward trend in deepwater; whereas, as you say, the reverse could be occurring in the lower 48.

Operator

Our next question comes from the line of John Herrlin with Societe Generale. Please proceed with your question.

John Herrlin

I just have a quick one for Brian. For the five factors you gave, what do you think is more critical, the depositional situation or the timing/vertical fractionation?

Brian Maxted

Yes, John. We're in a complicated 40 kind of world here, dealing with multiple processes that are interacting together. So the weighting and bias of each of those processes is, at this point in the development of the model -- and it is calibration which is still obviously quite early. It's difficult to predict. And that's why we try to move away from the individual source rocks and articulating those to one of consolidating the picture into simple, 1-in-3, 1-in-2 and 1-in-1 chance of finding liquids beyond 50 barrels an MCF.

As you move out into the -- as you move north into Mauritania and as you move south into Senegal, the influence of the shallower source rocks switching on is significant, we believe; particularly in northern Mauritania, where you are dealing with essentially intra-formational reservoirs within the upper Cretaceous and the Cenomanian through the Campanian. And there we've got, I think, a really good chance of finding liquids because of the contribution of those two source rocks and because those areas are being higher in the stratigraphy and more remote from the deeper source that's in a gas facies and gas maturity. And obviously, the examples there are Chinguetti and SNE.

As we move outboard on the Senegal and the Nouakchott River system, facies is important. And I mentioned in my script that it's based on -- the model is based on a number of assumptions. We have an outboard well and a deep-sea drilling project well that's got really good oil facies within the deeper Valanginian, Neocomian-Valanginian section. And then inboard, of course, we know that gas is sourced from that same reservoir.

So we're extrapolating. But directionally, we will see a more oil-prone facies within that charge horizon. We're much more confident with our control on the maturity now, given the calibration that we have.

So if it was one thing, I would say it's the source facies process and driver which will be key which is going to be aided by the fact that that source rock is close to the Cenomanian and Albian reservoirs; and, therefore, hopefully less fractionation is occurring.

John Herrlin

Was this something that you had a lot of discussions with, when you had the data room open?

Brian Maxted

It is, actually. As you know, we had three super majors in the data room. And what you are shown here is very much the consensus that came out of both our own work and the detailed technical discussions we had with all of the super majors, who were obviously very focused on finding liquids in this basin as well. And I would say there was a general consensus around the fact that there are no dry gas basins in West Africa. We're dealing with three oil source rocks. We do have an oil field to the north and an oilfield to the south of us. And we do have gases which suggest there is an oil component in the system.

So based on all of that, the question is where is the sweet spots for oil? And we believe that math is probably going to end up, in general terms, a good depiction of the distribution of liquid content in this basin. Obviously, it will be subject to, in detail locally, refinement as we put more holes into the petroleum system.

Operator

Our next question comes from the line of Al Stanton with RBC. Please proceed with your question.

Al Stanton

Brian, really with respect to that last comment in terms of the distribution of the liquids and that is where you are seeing the value; how do you see the value of liquids or the discovery of further gas impacting on the Tortue development? Because you are starting with a field that straddles the border. I would have thought you would start with something easier, particularly given that there is potentially a substantial 60 Tcf gas prospect in a single country just to the south.

So how can you present slide 5 and say, well, we hope to find something completely different that would surely ultimately change the timings that you present in slide 5?

Brian Maxted

Al, I'll let Andy answer that question. I would say it has been a major discussion point internally, with the governments and with all the data room attendees, including BP. So I'll let Andy answer that.

Andy Inglis

And I think it's a conversation that, as Brian said, that we've had with the farmanees and with the government. Simply said is is that Tortue is a world-class gas discovery. It is very LNG friendly because it has the right amount of liquids, but not too much. It has massive well rates in terms of the quality of the reservoir. It's in the thickest part of the depositional zone because it's in the core of the river system. And that will benefit from that.

So it is the ideal LNG gas project. And we think that if we were to find additional gas, as it comes with additional liquids, with sort of liquid stripping gas will actually be probably the way forward; and, therefore, those projects probably wouldn't be exporting gas. You would be using the gas to recharge the reservoir.

So we've had the debate with both governments. Both governments are fully behind an early gas development. They are fully behind a gas development that can be delivered in 2021. And Tortue can absolutely do that. So we don't see any bifurcation in agendas between the countries if we find additional resources.

I think what we will find is additional projects being done in parallel, potentially an oil project and maybe a liquid stripping project in another country. Who knows? But the fact that Tortue will anchor an LNG development that enables early gas in 2021 is absolutely the agenda of the partnership with BP and the agenda of both governments.

Al Stanton

So you are quietly confident you have two Mozambiques, rather than the Mozambique and the Tanzania?

Andy Inglis

I know; I'm confident that what we have -- and I'm confident in what we have is, we have a low-cost LNG project today that is cost competitive; and, therefore, is gas that is absolutely going to move forward. I'm confident in that. I am also confident there will be follow-up projects that will involve liquids and/or black oil. That's what I'm confident about.

Operator

Our next question comes from the line of Pavel Molchanov with Raymond James. Please proceed with your question.

Pavel Molchanov

So the fact that FID on the LNG development is not expected until next year -- is that partly to enable an integrated resource development, should you find liquids over the next 12 months?

Andy Inglis

No. It's simply the time it takes to get from where we're today with the subsurface appraised. We need further work with the DST to ensure that we have the gas composition nailed which then allows FEED to start in the third quarter which is typically a six-month process that would allow us to be in a position to demonstrate commerciality, mid-2018 which would then allow the FID decision to be made. So this is being driven by the timeline to do the engineering necessary to get to FID, not anything else.

Pavel Molchanov

Okay. But if you were to make a liquids discovery, as you are anticipating, would there be, at least theoretically, the possibility of integrating the two development cycles into one? Or would they be treated completely separately?

Andy Inglis

Pavel, today, the way that we would see it is they would be separate developments, geologic -- geographically, they are separate. Geologically, they would probably separate, at different pressure regimes. And they probably have different drivers around liquids versus gas. And as I said in the answer to Al's question, you have in Tortue a gas resource which is very well disposed towards an LNG development. And we have a very credible, low-cost scheme that enables that to go forward.

I think thereafter, you then have to think about how you would do a black oil maybe in parallel with it. And then, if you know, you had a rich liquids gas discovery, how you optimize the liquids recovery from that, you certainly wouldn't be exporting gas. So those are very different schemes. And I think you should see them as separate projects which will run in a sequence, but probably parallel overlap between them.

Yes and then maybe I'd follow up. Maybe one of the reasons we decided to farm down at this stage was to bring in a development partner like BP that has the capability of doing projects of this scale in parallel; and, clearly, the ability for us, as a 30% share with the balance sheet strength, is that we can move along with that. That was part of the whole strategy. Now is the right time to enable us to be at a credible working interest that allows us to move forward with multiple projects.

Operator

Our next question comes from the line of Neil Mehta with Goldman Sachs. Please proceed with your question.

Neil Mehta

Just more housekeeping questions, to start off. I Wanted to confirm that you said you'd expect and 11 Ghana liftings, net to Kosmos. I believe in the January presentation, you had said 10 liftings, net to Kosmos. So just want to confirm. And then what changed?

Tom Chambers

It is 11 cargos. And obviously, we've had some more time. We factored in the 10 operations; and what we think Tullow with a shorter shutdown, in our view, on Jubilee. So that gives us 11 cargos.

Neil Mehta

And then you rattled off some numbers in the beginning about production levels at Jubilee and TEN, thus far in the first quarter. Can you go through that again? There was some trade press about some of the downtime at Jubilee, in particular. But it sounds like you guys are running okay.

Andy Inglis

I'm not sure what trade press you are referring to, Neil. But in the first quarter we have been going through a process of ensuring that we deliver the spread mooring project. That project is very close to being finished, a matter of days away. While we have been doing that, you are clearly working at the aft of the vessel which has interrupted some of the offloading. So that's probably the up-and-down that you have been reading in the trade press; nothing that wasn't planned.

And actually, the most important thing out of it is that when we have had periods where we have had stable access to the offloading, with the two shuttle tankers which gives you -- it removes the constraint on the offloading, the production level has been very high, up to the 120,000-barrel-a-day number that I talked about which is the FPSO vessel. So clearly reservoir working well, vessel working well and we have been working on ensuring that we get the spread mooring done. That has obviously caused some downtime on the production levels while we have been doing that.

Neil Mehta

And then the last housekeeping question for me is -- I guess in 2018, we should expect FID at Tortue. What percentage of the asset do you need to have committed from a marketing standpoint before it's ultimately sanctioned? And the gas market is oversupplied, but I think there are some idiosyncratic things about the fass that make you more comfortable around your ability to market the assets. So can you talk about that?

Andy Inglis

Yes. Well, I think you know -- you need to think about -- I'll just make two big points. The first is with the development scheme that we have, we have an incremental phasing of the buildup of the LNG capacity; an initial vessel gives you around 2.5 million tons. The second -- which would be 2021 -- a second vessel, probably about 18 months to 2 years later, builds that up to around 5. So you're not putting a lot of LNG on the market in one go, point one.

The second point is part of bringing BP to the table was not only do they have the deepwater expertise, the LNG development expertise, they also have a very large LNG portfolio. And so, therefore, they are a credible buyer of the incremental production. And that was one of the things that attracted them to the project was they are looking for new sources of gas. You are probably -- as you are well aware, that they bought the Mozambique gas recently.

So I firmly believe, as I said in my remarks, that I don't see the marketing of the gas, the quantities we’re talking about here and the ratable buildup of those quantities to be an issue. The fundamental issue is ensuring that you have the lowest-cost gas around. And that's what we’re targeting in terms of the $5 per MCF FOB. So I feel good about the marketing of the gas and it will not be an impediment to the pace at which the project moves forward.

Operator

We have reached the end of the question-and-answer session. I would now like to turn the floor back over to Neal Shah for closing comments.

Neal Shah

Thank you, Operator. We appreciate all of you joining us on the call today and your interest in Kosmos. If you have any further questions, please don't hesitate to contact me. Thank you very much.