SECOND QUARTER 2017 EARNINGS REVIEW REMARKS

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[Zach Dailey]

Welcome to Marathon Oil Corporation's second quarter earnings review. I am Zach Dailey, Vice President of Investor Relations. The synchronized slides that accompany this review can be found on our website, at MarathonOil.com. Additionally, we'll conduct a live question and answer webcast on Thursday, August 3rd at 9 am Central Time.

Slide 2 contains a discussion of forward-looking statements and other information included in this presentation. Our review will contain forward-looking statements subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied by such statements. Please read our disclosures in our SEC filings for additional discussion of these items.

Reconciliations of the non-GAAP financial measures we discuss can be found in the quarterly information package on our website.

Participating on this webcast are Lee Tillman, President and CEO; Dane Whitehead, Executive Vice President and CFO; and Mitch Little, Executive Vice President of Operations. With that, I'll turn the presentation over to Lee who will begin on slide 3.

[Lee Tillman]

Thanks Zach. I'd also like to extend my welcome to those listening. I'll begin on slide 3. We achieved outstanding operational performance in the second quarter across the portfolio, delivering on our commitment to resume sequential production in the resource plays, which were up 6 percent from Q1, contributing to U.S. production exceeding the high end of our guidance. Our international business also exceeded the midpoint of guidance at 127,000 BOE per day driven by a very strong quarter from EG. Overall company growth was 6 percent, excluding Libya, which continues to ramp up production.

At a basin level, Oklahoma grew 11 percent sequentially while maintaining their focus on the strategic objectives of leasehold, delineation and infill spacing pilots. The Hansens black oil infill pilot came online in the STACK Meramec and delivered an IP 30 of 915 BOE per day for the six new infill wells, excluding the parent.

The Eagle Ford was free cash flow positive with production up sequentially on fewer wells to sales, due to outstanding well performance, as evidenced by the 2,340 BOE per day average 30 day IP from our top 10 second quarter wells. Early results from wells in Atascosa County are encouraging, and could serve to uplift the economics in that area as we exploit the oil window farther west.

The Bakken returned to sequential growth and delivered impressive results from our first two Hector wells with advanced completions, delivering an average IP 30 of 2,500 BOE per day and signaling a successful start to elevating the returns in this area where we have a large acreage position.

And finally in the Northern Delaware, we've built an outstanding asset team, ramped to three rigs as planned, brought on our first well with an MRO-designed completion, and are preparing for an exciting second half of the year.

We closed on the sale of our Canadian oil sands business and our Northern Delaware acquisitions, and ended the quarter with $2.6 billion of cash on our balance sheet, up from the first quarter.

Dane and Mitch will walk you through more of the financial and operational details in a moment, but before I pass it to them, I'd like to provide an update on our view of the second half of 2017 and an early look into 2018.

On slide 4, we provide updates to our 2017 capital program and production guidance.

We began 2017 with some key questions, some key uncertainties embedded into the assumptions that formed our capital program—an Oklahoma program heavily weighted toward delineation, leasehold and infill spacing pilots; a Bakken program seeking to test the response of the Hector area to high intensity completions; an Eagle Ford program driving for the next level of efficiency while looking to enhance the performance of the oil window farther west; and the integration of a newly acquired acreage position in the Northern Delaware.

And of course one of our biggest assumptions was the expected pricing of WTI which we placed originally at $55. We now have more clarity.

So with just over half the year behind us, our material progress against our strategic objectives, coupled with our asset teams exceeding initial expectations on efficiency, base performance and new well productivity, have enhanced our production outlook for the remainder of the year.

Specifically, we are raising the midpoint of our full year total company production growth guidance adjusted for divestitures to 7 percent. Similarly, our exit to exit rate guidance for the resource plays will move from 20 to 25 percent to 23 to 27 percent. All while lowering our full year capex by about 10 percent.

With the confidence that we will meet our strategic objectives and exceed our original volumes growth commitments, we can limit our outspend and remain positioned to maintain operational momentum into 2018.

And though we are just beginning to work our 2018 business plan, our capital allocation priorities remain the same—the strategic objectives of leasehold, delineation and infill pilots for the STACK and Northern Delaware followed by allocation to the highest risk adjusted returns in the Eagle Ford, Bakken and SCOOP.

As a result of the 2017 exit rate momentum, we will carry a larger, higher margin production base into 2018 with the resource plays expected to account for a more significant proportion of the total production mix. This shift delivers stronger operating cash flow and underpins our goal to deliver growth consistent with our 2017 to 2021 benchmark CAGRs within cash flows at moderate pricing.

With that, I'll let Dane run through some of our financial highlights.

[Dane Whitehead]

Thanks Lee, I'll start on slide 5, and take a few minutes to provide an update on our cash flow performance and our go forward expectations.

Earlier in the year when we announced the sale of OSM and acquisitions in the Delaware, coupled with our 2017 capital program that is reigniting growth in the resource plays, we forecasted a cash flow outspend for the year, at the time assuming a $55 WTI price.

The waterfall on slide 5 shows we did great on this metric for the first half of 2017, generating positive free cash flow with an average WTI price of $50 for the first 6 months. Our YTD cash balance increased by about $125 million to $2.6 billion at June 30. Keep in mind that this does not include the second $750 million installment on the OSM sale. We are going to receive that in Q1 2018.

The remaining capex for 2017 based on today's revision will help drive the midpoint 25 percent exit to exit growth rate that we are forecasting this year for our high margin resource plays, and will result in an outspend similar to our original intended range of $200 to $300 million, but now achievable at $50 WTI instead of $55. In our view, the second half of 2017 is a transient, "high water" mark for outspend.

As we transition into 2018, the lag between capital spending and the realization of production and cash flows should largely diminish, and our cash flow outlook is much improved.

The 2017 production growth rate, driven by the higher margin resource plays, should provide a solid base of cash flows to fund our continuing growth into 2018 and while it is obviously too early to talk about a 2018 capital plan, our objective remains to deliver strong growth within cash flows.

If you go back to our multi-year benchmark case that grows resource plays at 18 to 22 percent and total company production at 10 to 12 percent, while living within cash flows at $55 oil, we now believe we can achieve that same outcome in the low $50's.

On to slide 6, I wanted to highlight some recent transactions that further strengthen our financial position and meaningfully increase our flexibility.

In July we priced $1 billion of 4.4 percent senior notes that mature in 2027. In mid-August we will use these proceeds plus cash on hand to redeem our 2017, 2018 and 2019 maturities totaling $1.76 billion which creates numerous benefits, including – extending our next debt maturity out to 2020, reducing gross debt by a little over $750 million, and reducing our annual cash interest expense by over $60 million.

In parallel with the new bond offering, we worked with our bank group to extend our credit facility by one year to 2021 and in the process upsized it to $3.4 billion, all of which is undrawn.

Of course we have been in steady dialogue with the ratings agencies, and they have been very supportive of these moves which improve our strong financial position which is the foundation of our business and enables us to confidently execute on our strategy.

With that, I'll hand it over to Mitch Little who will discuss our operations in a bit more detail.

[Mitch Little]

Thanks Dane. I'll begin on slide 7 with a chart highlighting our resource play and U.S. segment production. Production in the second quarter exceeded the top end of our guidance range. In the resource plays, we delivered 6 percent sequential growth, anchored by continued strong base and development well performance in the Eagle Ford, the addition of 4,000 BOE per day from the Northern Delaware, as well as double digit growth in Oklahoma.

Production from our other U.S. assets also outperformed expectations, driven primarily by the Gulf of Mexico.

For the third quarter, we expect further growth in the resource plays and we're guiding U.S. production to a range of 230,000 to 240,000 BOE per day, an increase of 4 to 8 percent.

Diving into the specific assets, I'll begin with Oklahoma on slide 8. Oklahoma posted a quarter with double digit growth, up 11 percent to 49,000 BOE per day. We brought 20 gross operated wells to sales, including the Chapman well, which was an extended lateral Meramec volatile oil well that posted an average 30 day IP of nearly 3,200 BOE per day, 52 percent oil.

We also brought our second Meramec infill spacing pilot online, which is the 3rd industry full section spacing pilot in the black oil window, which extends across approximately 600 square miles. The Hansens infill program was designed as a multi-dimensional pilot to maximize learnings at this early stage in the Meramec development cycle. As you can see from the diagram in the bottom left, the 5 wells in the western part of the section were spaced 660 feet apart horizontally across the upper and lower Meramec, effectively testing an 8-well per section density. These 5 wells had an average IP 30 of 980 BOE per day, with the strongest performing wells being the four western most. The early performance is encouraging and supports our base case assumption of 6 wells per section, but we still need to see some longer term performance for final confirmation.

In the bottom right part of the diagram, you'll see that we also trialed an infill well between two existing producers: our Hansens parent well which has cumulative production of 380,000 BOE and an existing industry well in the adjoining section. Based on early data, this well would not feature in a development scheme, but we were able to garner valuable learnings on direct offset impacts. The average lateral length from the 6 new infill wells is 4,650 feet, and the 30 day IP from the 6 new infills was 915 BOE per day and 55 percent oil.

The trial also tested multiple completion designs where pump rates, fluid types, fluid volumes and use of diversion were altered across the pad. We collected a cadre of technical data, including use of electromagnetic proppant, micro-seismic, and other fracture characterization methods which we are currently integrating with well performance data to allow us to continue to optimize completion techniques. Completed well costs for the 6 infill wells averaged $4.3 million.

Industry is in the very early innings of the Meramec black oil infill development optimization. Typical of most plays, unique approaches will be required to maximize returns specific to the characteristics of the play. We will need to monitor extended production data on these wells, and integrate learnings from the technical data acquisition into further optimization of the next trials.

For the balance of the year, we expect 30 to 40 wells to sales, about half of which will be leasehold protection. We'll continue our focus on leasehold drilling, while bringing our Marie infill in the Springer, our 9-well Tan XL in the Meramec volatile oil window, and potentially the Eve, another Meramec black oil infill, to sales in 2017.

The next infill for us will come to sales in Q3, and is in the SCOOP Springer oil window. There will be 4 new Springer wells in the section, and they'll be above 6 existing Woodford producing wells from a much earlier vintage, for a total density of 10 wells in a single section. Completion activities will also commence on the Tan infill during the third quarter, with first sales expected to be in Q4.

On slide 9, we illustrate some of the strong Q2 well performance from across our Oklahoma leasehold in the STACK and SCOOP. In the chart on the top left, we highlight performance of our recent Meramec volatile oil extended lateral wells, all of which are exceeding our 1.5 million BOE type curve. The Calf Rope and Strack wells came online at the beginning of Q2, and continue to perform above type curve after 90 days online. The Chapman well I mentioned earlier is shown in yellow, and is off to a very impressive start with higher than expected oil cut. The Alta BIA, in the Gas Condensate Window with an IP 30 of roughly 2,100 BOE per day, and the McKinley BIA in the Gas window with an IP 30 of nearly 18 million cubic feet per day, are a couple of our leasehold wells showing strong performance, and illustrating the importance of capital allocation to preserve our valuable position across the state.

With our position in the SCOOP largely HBP'd, we have had low activity there. In Q2 we brought the Isaac Taylor well to sales, with an IP 30 of just under 1,800 BOE per day. The well was drilled for lease protection, and we trialed a lower proppant loading design of 1,200 lbs per foot which has yielded some impressive early time results, at lower cost than our traditional 1,800 lbs per foot design.

As I previously mentioned, in Q3, we will be bringing our first SCOOP Springer infill pilot to sales, as we continue to progress towards a development drilling bias in 2018 across both the STACK and SCOOP.

Moving to slide 10, the Eagle Ford delivered outstanding second quarter results with production of 100,000 net BOE per day, up from the prior quarter with fewer wells to sales.

Our second quarter production was bolstered by exceedingly strong well performance, where our top 10 best wells had average 30 day IPs of over 2,300 BOE per day, and were almost 70 percent oil. In July, we brought on two 5 well pads in Atascosa County. We pumped our higher intensity completion design at both pads, and we're seeing encouraging early results from them as we look to extend this latest generation design across our position.

Our Eagle Ford team has set the benchmark for execution efficiency that we expect our other assets to achieve over time with higher and more consistent activity levels. In the second quarter, we averaged completed well costs approximately flat with Q1, while continuing to increase our drilling and completion efficiencies. We set a new internal drilling record for the fastest well we've ever drilled at over 4,200 feet per day – just 4 days to drill over 17,000 feet measured depth – while our top performing frac crew pumped over 200 stages per month for the sixth consecutive month. And we're not going to stop there. This month, we will mobilize what we believe to be the world's first land-based Quad-Rig. By employing cutting edge technologies and taking innovative approaches to our operations, we expect to continue to push the technical limits in operational efficiency and deliver better wells while controlling costs.

We've included a chart in the bottom left to highlight the trend of well performance on an IP 90 basis, normalized for lateral length, dating all the way back to when we entered the play in 2011. As you can see, we've consistently improved on this basis, year over year, through a focus on continuous improvement and technological innovation.

With our current plan of development, and at this year's pace, we have about 10 years of risked remaining Company-Op inventory across the Eagle Ford.

For the balance of this year, we expect to bring 65 to 70 gross operated wells to sales, about two thirds of which will be in the oil window. We'll continue to balance the program between some core Karnes County wells in addition to extending testing of our higher intensity completions in areas farther to the west in an effort to validate their economic competitiveness within our portfolio, following the strong results from our two Atascosa County pads that we released in Q1 results.

Slide 11 highlights some of our positive second quarter well results in the Eagle Ford. Our best results this quarter came from three Karnes City pads in the eastern part of our oil acreage in Karnes County. The averages of those pads ranged between 2,150 to 2,400 BOE per day, with oil cuts over 70 percent.

As shown on the IP 90 chart from the previous slide, we continue to integrate learnings from having completed over 1,500 wells in the Eagle Ford, and have optimized both costs and performance on a continual basis. We are to the point where we have customized designs to specific areas of the field, and in some cases on a well by well basis, which results in proppant loading ranging from 1,200 to 2,200 lbs per foot as we prioritize delivering value over simply high initial production rates.

Again, I can't say enough about how well – and how consistently – our Eagle Ford team has performed in 2017. With average well costs of about $4.2 million that generate these types of results, you can see why this is our most capital efficient asset that generates free cash to help fund the development of our other plays.

The light blue box on the left side of the page highlights 2 additional Guajillo pads we brought to sales at the beginning of Q3 that have shown encouraging early results. More to come on those wells in the future…

Turning to the Bakken on slide 12, our second quarter production of 49,000 BOE per day was up slightly from the prior quarter with only two new wells to sales in Hector. There were two pads expected to come to sales in Q2 that slipped by a few weeks into July due to a performance issue with one of our pressure pumping service providers. Importantly, we have already taken action, and have switched to a higher performing pressure pumping provider.

The two pads we expected to come to sales in late Q2 are now on-line, and performing extremely well with average 24 hour IPs over 4,000 BOE per day. One of the wells, the Cunningham USA 31-41 in West Myrmidon, established a new Marathon record 24 hour IP, with over 5,000 BOE per day.

The highlight of the second quarter, came from the Hector area, where we brought on our first two modern generation completion trials. We employed high intensity completions similar to the successful techniques we've proven in Myrmidon. These wells had average IP 30s of 2,500 BOE per day, with oil cuts of 85 percent, and exceeded our expectations for early performance. I'll get into a bit more Hector detail on the next slide.

Turning to the chart on the bottom left of the page, we've plotted well performance from all of our Myrmidon pads since late 2015, both from the East and West side of the river. What you can clearly see is that there's very consistent performance over time from these areas, where we've focused on precision targeting in both the Middle Bakken and Three Forks formations, as well as employing state-of-the-art enhanced completion technology. We're looking forward to the second half of the year, where about two thirds of our 35 to 45 gross operated wells we'll bring to sales will be in Myrmidon.

Flipping to slide 13, I'll dive into the Hector well performance and completion trials a bit further. What you can see in the bottom left chart is the performance of our first two Hector wells plotted against our Hector type curve which was based on an early generation completion design. The two new wells were each completed with about 8 million pounds of proppant, 45 stages plug 'n perf, and similar 215 foot stage spacing. The Middle Bakken Mittelstadt well was a slickwater job that utilized multiple diverter drops, while the Three Forks Hondo well was a hybrid job with a single diverter drop.

While results from these enhanced completion trials are very encouraging in the early days, we'll be drilling and completing several other pads throughout the balance of the year to enhance the data set. These upcoming pilots are spotted on the map in the light blue circles. We see some variability in reservoir quality across our Hector acreage position, with the highest overall quality generally in the Northern and Western portions of our position. The remaining 2017 pads will test a broader representation of the opportunities across our Dunn County acreage, with the eastern most pads designed to test how far we can successfully extend the enhanced completion technique.

We believe that it's very important to progress these tests to gain a full understanding of the potential of our 120,000 net acre position in Hector, and how it will fit into our future development plans for the Bakken. It's clearly a very exciting start for a new chapter of our Bakken story.

On slide 14, I'll turn to the Northern Delaware, where we have positive results from a couple wells to share. In the second quarter, the Northern Delaware contributed 4,000 BOE per day net to Marathon due to the intra-quarter closing dates of our acquisitions.

In the quarter, we brought two wells to sales in Eddy County, the Cypress and Black River wells. The Cypress well was a 4,600 foot lateral Wolfcamp X-Y well that had an average IP 30 of 1,500 BOE per day at 72 percent oil. It was a Western delineation well that employed our team's first completion design and was 100 percent slickwater, 2,200 pounds of proppant per lateral foot, 24 stages pumped and 5 clusters per stage. While Tom and his team will customize the completion design based on a variety of factors, this will basically be the foundation for our first generation design in the Northern Delaware.

The other second quarter well, the Black River, came to sales early in Q2, and was also a Wolfcamp X-Y well, but a 9,400 foot lateral. We've plotted its 2-stream production in the top left chart. As you can see, production has been relatively flat for the first 90 days, with a 2-stream 90 day IP of nearly

1,300 BOE per day, and 73 percent oil. An impressive first 90 days, and indications that early time could probably be further enhanced with a more aggressive choke management strategy.

We ramped to 3 rigs mid-year, as planned, and in the second half of the year we'll bring 15 to 20 gross operated wells to sales. In addition to these wells to sales, the team will be focused on drilling our first infill spacing pilot around the Cypress 1H, which will be 7 new wells within 320 acres testing an 8 well spacing design on half of a section, which equates to an effective 16 well per 640 acre DSU spacing for the five benches being targeted in the trial. The test includes two wells in the 2nd Bone, one in the 3rd Bone, an additional X-Y, as well as two wells in the upper Wolfcamp and one in the middle Wolfcamp.

On slide 15, we've spotted the Black River and Cypress wells, which I just discussed in dark blue boxes, both in Eddy County. Additionally, we've highlighted some of our upcoming activity which will include delineation and leasehold protection across both Eddy and Lea Counties. All of our activity in the second half of the year will be focused on Bone Spring and Wolfcamp targets.

The Battle 34 Federal 4H, in central Lea County is a 2nd Bone Spring, standard lateral which is on early flowback with encouraging results.

The Grama Ridge DSU will include three standard lateral wells, two 2nd Bone Spring, drilled at a 4 well/section density, as well as a 3rd Bone Spring test. The 3rd Bone Spring test is a seismically derived target, where we also leveraged sub-regional mapping, and petrophysical analysis of nearby wells. The 3D seismic data shows a focusing of sand deposition in the lower 3rd Bone Spring along the lateral, and we have designed the well path to encounter the thicker reservoir section in this area.

In our Southern Comfort DSU we will place two 7,500 foot laterals in the Wolfcamp XY in an area where we have seen some encouraging well results from recent offsets. While in the Cass State DSU we intend to drill 3 standard lateral wells, one each in the Wolfcamp XY, Wolfcamp A, and 2nd Bone Spring. The Cass State DSU is located directly south of our Cypress 1H, which is performing well through the first 30 days.

Finally, on slide 16, I'll talk a bit about our International E&P highlights before handing back to Lee.

Our International segment had an excellent quarter, with production of 127,000 net BOE per day, near the top end of our guidance range. EG production averaged 107,000 net BOE per day, up from Q1, with production on plateau a year after the successful installation of our gas compression project. They delivered $134 million of EBITDAX in the quarter, helping fuel our development in the U.S. resource plays.

Libya continues to ramp, with net production averaging 11,000 BOE per day in Q2. We benefitted from two liftings from Es Sider in the second quarter which allowed us to recover our underlifted position. Since the quarter ended, production has ramped further, with current rates over 20,000 net BOE per day. While encouraging, we continue to exclude Libya from our guidance due to uncertainty associated with the political and operating situation there.

Finally, our third quarter International production guidance of 115,000 to 125,000 net BOE per day (excluding Libya) is slightly lower than second quarter due to scheduled turnarounds at both Brae and Foinaven in the U.K. With that, I'd like to turn it back to Lee for final comments.

[Lee Tillman]

Thanks Mitch, I'll wrap up on slide 17.

We don't pretend to predict pricing but rather want to prepare our business to be successful across a broad range—and a more moderate range – of pricing. That preparation includes the strength of our balance sheet, a low cost structure, a relentless focus on execution excellence, maintaining flexibility and agility in our capital allocation and an ongoing commitment to portfolio simplification and concentration.

All of this is designed to deliver long term value and returns to our shareholder.

We've had a very exciting first half of 2017, resumed growth in the resource plays, strengthened the portfolio and the balance sheet, and have posted positive results across our portfolio that allow us to increase our production guidance while reducing our capex and maintaining an upward trajectory into 2018. You should expect our capital allocation to remain a dynamic, real time effort as we continually optimize across our four basins, leverage learnings and respond to performance trends as well as the macro environment. Our drive for maximizing returns is neither static nor limited to an annual budget cycle.

At the heart of it all are our dedicated employees whose commitment and innovation has only been sharpened by these dynamic times.

That concludes our prepared remarks and we look forward to your questions during the live webcast tomorrow morning. Thank you.