2Q 2013 EARNINGS REVIEW REMARKS

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August 7, 2013

Welcome to Marathon Oil Corporation's second quarter 2013 earnings review. The synchronized slides that accompany this review can be found on our website, at MarathonOil.com.

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.

In accordance with safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Marathon Oil Corporation has included in its Annual Report on Form 10-K for the year ended December 31, 2012, and subsequent Forms 10-Q and 8-K, cautionary language identifying important factors, but not necessarily all factors, that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Please note that in the appendix to this presentation there is a reconciliation of net income to adjusted net income for the periods presented, as well as operating estimates and other data you may find useful.

Slide 3, provides an analysis of cash flows for the first half of 2013. Operating cash flow, before changes in working capital amounted to $3 billion, with over $1.4 billion generated in the second quarter despite a

$7.68 per barrel drop in our International E&P Segment's liquid hydrocarbon realizations. Changes in working capital were a use of $650 million, primarily due to cash tax payments in Norway and Equatorial Guinea, while cash capital expenditures for the first six months of the year totaled $2.7 billion; we had proceeds from dispositions of $333 million and debt repayments of $348 million. In addition we paid dividends of $241 million.

We ended the quarter with $246 million in cash and total debt of $6.5 billion, making our cash-adjusted debt-to-capital unchanged from year end at 25 percent.

Slide 4 shows the components of the 32% increase in our second quarter adjusted net income over the first quarter. Our North America E&P segment's after-tax earnings increased $280 million, a result of higher liquid hydrocarbon sales volumes from growth in the Eagle Ford and Bakken shale plays and lower unproved property impairments related to canceled or expiring leases. International E&P segment income was $71 million lower during the second quarter primarily as a result of lower price realizations for liquid hydrocarbons and lower volumes due to a planned turnaround in Equatorial Guinea, and fewer liftings at Foinaven in the U.K. The second quarter 2013 effective tax rate was 72%, 62% excluding Libya.

Slide 5 shows the North America E&P segment's second quarter 2013 earnings increased from a loss of $59 million in the first quarter 2013 to income of $221 million in the current quarter. As I mentioned earlier, the increase was a result of higher liquid hydrocarbon sales volumes in the Eagle

Ford and Bakken shale plays and lower unproved property impairments related to cancelled or expiring leases. The other increase of $42 million, quarter over quarter, was primarily driven by a realized gain on crude oil derivatives and the lack of impairments in the second quarter.

Slide 6 shows the changes driving our second quarter 2013 International E&P segment earnings. Segment income was lower in the second quarter primarily as a result of lower liquid hydrocarbon price realizations, as well as lower sales volumes and less income from equity method investments largely due to the previously mentioned planned turnaround in Equatorial Guinea in the second quarter.

Slide 7 shows our quarterly LNG and Methanol sales, reflecting the impact of the previously mentioned second quarter turnaround which was safely completed eight days ahead of schedule and under budget.

Slide 8 shows our Oil Sands Mining segment income decreased $18 million sequentially, primarily because of unplanned mine downtime and a planned turnaround at the non-operated AOSP in Canada. The total cost of the turnaround was approximately $25 million net, of which $16 million net occurred in the second quarter.

I'll now turn the call over to Clarence to discuss operations.

Slide 9 summarizes the key highlights for the second quarter. We continued to execute well operationally and overall E&P production available for sale, excluding Libya, came in at the upper end of our guidance. U.S. Lower 48 onshore production increased to 182,000 barrels of oil equivalent per day, an increase of approximately 6% driven by growth in the Eagle Ford and the Bakken. Our operated businesses again demonstrated world class operational excellence with reliability in excess of 98%, a truly outstanding achievement. As Howard mentioned, cash flow from operations was strong again this quarter as growth in higher margin U.S. production helped offset international liquid hydrocarbon realizations that were $7.68 per barrel lower quarter over quarter. Once again our operating teams did an outstanding job in planning and executing the turnaround in Equatorial Guinea, which was safely completed 8 days ahead of schedule and under budget.

We announced that we have entered into an agreement to sell our non-operated 10 per-cent working interest in Block 31 offshore Angola. Closing is expected to take place by the end of this year. We plan to use the proceeds principally to repurchase shares but also to strengthen the balance sheet and for general corporate purposes.

Moving to slide 10, I'll comment on our execution in our key resource plays and future expectations.

Eagle Ford second quarter production averaged 80,000 barrels of oil equivalent per day, an 11% increase over the prior quarter and an increase of approximately 280% compared to the same quarter in 2012. This production growth was driven by continued strong well results across our core acreage position. The migration to pad drilling continues with 85% of wells in the second quarter drilled off multi-well pads. Spud-to-TD time was a highly competitive 12 days during the second quarter and average wells drilled per pad increased from 2.6 to 3.1 quarter over quarter. Our 2013 target for Eagle Ford net wells drilled has been narrowed to 220 to240. We are currently operating 15 rigs and will continue to monitor the rig efficiency in order to manage our targeted annual well count. We are testing the

Austin Chalk and Pearsall formations within our acreage to assess their potential as part of our continuing strategy to maximize value. Four recent Austin Chalk wells averaged an initial 24 hour production of 980 barrels of oil equivalent per day from shorter 4,075 foot laterals with 11 stage stimulations and one Pearsall well yielded an initial production of 580 barrels of oil equivalent per day. Volume netbacks remain strong with both crude and condensate selling to LLS contracts, including a new contract in the second quarter at our best pricing to date. A new Y-grade pipeline connection to our Sugarloaf Gas Gathering system has increased netbacks of this product by $20 per barrel, positioning us well for further growth in the area. Results of the Eagle Ford downspacing study are expected to be released during our planned analyst day in December.

Production in the Bakken increased over 5% to an average of 39,000 barrels of oil equivalent per day during the second quarter with five rigs running. The targeted 2013 well count of between 65-70 net wells remains unchanged. We continue to ramp up activity in both the Middle Bakken and Three Forks, with 18 Three Forks wells drilled so far this year and 34 planned for 2013. We have proven excellent Three Forks productivity across much of Marathon's Bakken acreage as evidenced by our recent Williams 31-2TFH well that commenced production on July 9th with a 24 hour IP of 2,308 barrels of oil equivalent per day. In the second quarter, 100% of our Bakken wells were drilled from multi-well pads and we expect this high rate to continue with 92% of our wells for the second half of 2013 to be multi-well pads. We continue to access the highest netback markets through the optimization of pipeline, rail and local markets. We have an exceptional amount of optionality as we benefit from term local sales agreements made when we were a first-mover into the play and from not being hampered by significant rail infrastructure investment in order to move our barrels.

In the Oklahoma Resource Basins our targeted 2013 well count of between 15-19 net wells remains unchanged. In April we brought on the 3R well in the East Knox area which is our best Woodford well to date. The 3R well was drilled in 35 days spud to TD and commenced production on April 19th with a 24 hour IP of 2,545 barrel of oil equivalent per day. During the second half of 2013 we anticipate spudding two wells each in the central Oklahoma Mississippi Lime and the northwestern Oklahoma Granite Wash formations.

Slide 11 shows our 2013 refocused and very active exploration drilling schedule. The program has already resulted in the successful appraisal of the outside-operated Shenandoah prospect in the Gulf of Mexico during the first quarter. The Sabisa-1 well, on the South Omo Block in Ethiopia, where we own a 20% percent non-operated working interest, encountered reservoir quality sands, oil and heavy gas shows and a thick shale section. Because of mechanical issues the well was abandoned before a full evaluation could be carried out. The rig will now mobilize to the nearby Tultule prospect.

The Diaman-1 well in Gabon has reached target depth and logging operations and further evaluations are underway. Once the well data have been analyzed, the operator will release the results.

We're currently participating in seven exploration or appraisal wells and expect to announce the results of this program over the remainder of 2013.

Slide 12 demonstrates that since the first quarter of 2012, our quarterly worldwide production available for sale, excluding Alaska and Libya, has grown approximately 15 percent with a slight decrease in the base business in the second quarter, primarily as a result of a planned turnaround in Equatorial Guinea during the quarter. The growth wedge has increased 92,000 barrel of oil equivalent per day over this timeframe, driven mainly by our onshore production.

Slide 13 shows that our Lower 48 onshore production has grown approximately 114,000 barrels of oil equivalent per day from the third quarter of 2011 to the second quarter 2013. Importantly, liquids increased from 55 percent to 72 percent of total volumes over this same period. The 2013 second quarter production was 6 percent higher than the first quarter of 2013. And, we are on track to continue with strong growth.

Slide 14 shows both the historical available for sale and sales volumes for the North America and International E&P segments including Libya and Alaska. Production available for sale decreased 2 per cent from the first quarter, again largely due to the Equatorial Guinea turnaround, but increased 14 per cent over the second quarter of 2012.

At the end of the second quarter we had a cumulative underlift of approximately 2.9 million barrels of oil equivalent per day. Of this, approximately 2 million barrels of oil equivalent per day is natural gas in Libya. On the liquids side, we are underlifted approximately 760,000 barrels in Libya and 260,000 barrels in Equatorial Guinea. We are overlifted approximately 90,000 barrels in Angola, 75,000 barrels in Norway and 20,000 barrels in the U.K.

Slide 15 compares total company liquid hydrocarbon sales volumes excluding Libya, for the second quarter 2013, first quarter 2013 and second quarter 2012. Actual sales volumes grew approximately 19 per cent between the second quarter 2012 and 2013, with the U.S. percentage growing from 34 per cent in the second quarter of 2012 to 46 per cent in the second quarter of 2013.

Slide 16 shows this same comparison for actual second quarter 2013 sales volumes to estimated third quarter 2013 sales volumes.

Slide 17 illustrates our previously stated goal of achieving a 5 to 7 percent compounded average growth rate between 2010 and 2017. The growth is primarily being delivered by our onshore U.S. plays.

Slide 18 shows our International E&P quarterly cost structure per barrel of oil equivalent per day. DD&A per BOE in the first and second quarter of 2013 was negatively impacted by our first liftings from Angola Block 31, which is typical for a development in its early life. Production expense increased in the second quarter 2013 relative to the first quarter primarily as a result of the cost incurred in Norway on workovers of water disposal wells. Other expense per barrel decreased in the second quarter mainly as a result of litigation expense that was recorded in the first quarter.

Slide 19 depicts the International E&P cost per barrel of oil equivalent trend without Libya.

Slide 20 provides our estimate for the 2013 International E&P cost per barrel of oil equivalent, and this excludes Libya. The higher operating costs per BOE reflect the projected decline in our Norway production and the cost of turnarounds and workovers incurred to date and scheduled later in 2013.

As shown on slide 21, total North America E&P costs per barrel of oil equivalent per day decreased quarter over quarter, primarily because of lower exploration costs, but cash production and other operating cost per BOE were also lower by about 3%.

Slide 22, provides the estimated 2013 operating costs per barrel of oil equivalent per day for the overall North America E&P segment and the Eagle Ford.

That concludes our prepared remarks and we look forward to your questions during tomorrow morning's earnings call. Thank you.