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ExxonMobil's U.S. Upstream Results Underwhelm, Again

Exxon's U.S. Upstream Division, Anchored by the Permian, Makes up Little Ground After Years of Disappointment

By some measures, the second quarter of 2021 was the best quarter in years for ExxonMobil's U.S. oil and gas operations. Quarterly earnings jumped to $663 million—the best results for the company's U.S. upstream segment since 2017, and a $300 million gain from the first quarter.[1] This improvement was largely due to a 14 percent increase in U.S. oil prices, even as the company's U.S. oil production inched up by 3 percent. The combination of higher prices and slightly higher volumes boosted IEEFA's estimates of the company's U.S. oil and gas sales revenues to their highest level since the third quarter of 2014.[2]

Yet by other measures, the company's U.S. upstream operations have yet to regain their footing after a decade of turmoil. Back in 2014—the last time the company's U.S. operations generated this much revenue—earnings from the U.S. upstream segment were almost twice as much. Meanwhile, the hangover of expensive write-downs still lingers: Since 2013, ExxonMobil has invested $61.5 billion on U.S. upstream capital projects, but has reported a cumulative loss of $5.3 billion, largely on the back of massive write-downs of U.S. assets. Without a roughly $7 billion gain from 2017 changes to U.S. tax law, Exxon-Mobil's US upstream losses would have been even steeper (See Figure 1).[3]

By any reasonable standard, spending $61 billion while losing $5 billion represents a bitter pill for investors. But if anything, these results may understate the financial troubles experienced by ExxonMobil's U.S. upstream division. The problems may be easiest to see in the Permian Basin, which ExxonMobil has repeatedly described to investors as one of the company's key growth projects. A quick recounting of ExxonMobil's Permian ventures since 2017 reveals an ever-shifting narrative about the Permian's position in the company's portfolio, over-ambitious targets that the company has missed again and again—and ample reasons for skepticism about the company's future prospects in the Permian.

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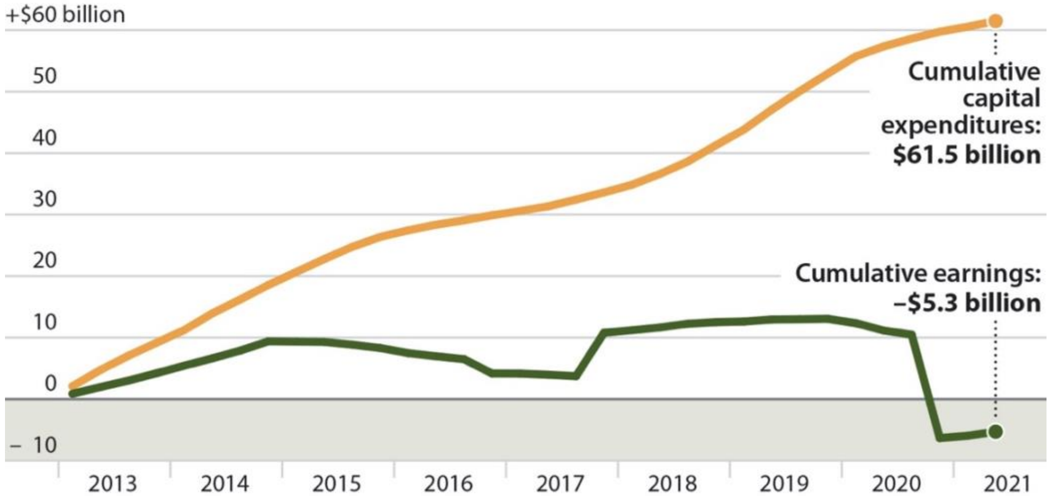
[1] ExxonMobil. Second Quarter 2021 Earnings Supplement. July 30, 2021.
[2] IEEFA estimate, derived from ExxonMobil, Quarterly Earnings Archive.
[3] IEEFA estimate, derived from ExxonMobil, Quarterly Earnings Archive. Cumulative earnings for ExxonMobil's U.S. Upstream segment include a $7.1 billion gain in the fourth quarter of 2017 due to financial benefits from changes to U.S. tax law. Earnings also include write-downs in ExxonMobil's U.S. Upstream portfolio, including a $16.8 billion impairment in the fourth quarter of 2020.

Figure 1: Exxon's U.S. Upstream, Cumulative Earnings vs. Capex, 2013-2021



Source: ExxonMobil quarterly earnings supplements.

In January 2017, the company announced a $5.6 billion, all-stock acquisition of a massive acreage position in the Delaware Basin said to contain 2.5 billion barrels of oil accessible via hydraulic fracturing, or fracking.[4] ExxonMobil also promised future cash payments of as much as $1 billion to the previous owners of the acreage.

Not even two months later, the company told investors that its Permian position constituted a "short-cycle" asset, which the company defined as an investment "expected to generate positive cash flow less than 3 years from the date of investment."[5] This was a remarkable claim: At the time, the U.S. fracking industry had never succeeded in producing consistent, positive free cash flows, even when oil prices regularly topped $100 per barrel.[6] There was little reason to believe that ExxonMobil could reverse this trend. The company's fracking operations had proved unexceptional,[7] and oil prices at the time were less than half their peak from a few years earlier.[8]

[4] ExxonMobil. ExxonMobil to acquire companies doubling Permian Basin resource to 6 billion barrels. January 17, 2017. Note that ExxonMobil described the new Permian acreage as containing "3.4 billion barrels of resource, of which 75 percent is liquids."
[5] ExxonMobil. 2017 Analyst Meeting. March 1, 2017, p. 19.
[6] IEEFA. In a Tumultuous 2020, Shale Firms Slashed Capex to Generate Cash. March 2021. Note that during ExxonMobil's March 2017 Analyst Meeting, independent financial analysts raised significant questions about the risks faced by the company in the Permian, including the broader oil and gas industry's inability to generate fracking profits, ExxonMobil's apparent business paradigm shift in the Permian, a growing likelihood of diluted company profits, and a failure by the company to develop the fracking model internationally.
[7] IEEFA analysis of IHS Markit data. Note: IEEFA compared ExxonMobil's performance with the performance of large peers operating in the Arkoma, Strawn, Permian, Williston, and East Texas basins—the regions in which ExxonMobil had drilled and completed at least 400 horizontal wells from 2007 through 2016—measured by estimated historic breakeven prices and peak production rates per 1,000 lateral feet for wells drilled in the same year.
[8] U.S. Energy Information Administration. Cushing, OK WTI Spot Price FOB. Accessed August 3, 2021.

ExxonMobil drilled initial wells in its new acreage during 2017, and the company added to its Permian acreage in the early fall.[9] After evaluating early drilling results from its new acreage, in January 2018 the company set an ambitious target to produce 600,000 barrels of oil equivalents from the Permian, including both liquids and gas, by 2025.[10]

Over the next year, the company ramped up its drilling in the Permian and achieved some encouraging results by selectively drilling in promising locations.[11,12] But as the Permian drilling program advanced, the goal of generating "short-cycle" cash receded. As with virtually every major fracking-focused enterprise, ExxonMobil's Permian operation steadily spent more cash on drilling than it generated by selling oil and gas from its new horizontal wells. Based on IEEFA's analysis of IHS Markit data, new Permian Basin fracked wells operated by ExxonMobil produced cumulative negative free cash flows of roughly $1.2 billion from 2017 through 2018 (See Figure 2).

Figure 2: Cumulative Free Cash Flow From ExxonMobil Permian Horizontal Wells Brought Into Production 2017-2020

Source: IEEFA estimates, based on IHS Markit Dynamic North America database. See appendix for explanation of free cash flow estimation methods.

[9] ExxonMobil. ExxonMobil continues to increase acreage position in Permian Basin. September 27, 2017.
[10] ExxonMobil. ExxonMobil to triple Permian production by 2025, expand transportation infrastructure. January 30, 2018.
[11] IEEFA. ExxonMobil: Permian Leader or Just Another Fracker?" June 2021.
[12] ExxonMobil. Upstream Spotlight: Unlocking Permian value. October 2, 2018, p. 25.

This cash burn was not the result of sub-par wells or unusually costly drilling. Instead, it was simply the predictable financial result of any major fracking program aimed at achieving rapid production growth. As the program ramps up, a fracking operation must make substantial capital expenditures on drilling and completing wells, and on installing gathering and processing infrastructure. The cash necessary to ramp up drilling quickly typically far outweighs the relatively modest short-term cash generated from new production. As the U.S. fracking industry had long since discovered, negative cash flows can persist at the corporate level for many years, even if individual wells eventually pay for themselves.

As the Permian cash burn mounted, ExxonMobil could have backed away from its ambitious and unprecedented twin goals of rapid production growth and "short-cycle" cash generation. But instead of pulling back, ExxonMobil doubled down. In March 2019, the company told investors that it had set a new and far more ambitious goal of producing 1 million barrels of oil per day from the Permian "as early as 2024."[13] In short, the company claimed that it could produce two-thirds more oil than it had previously claimed while meeting its target a year earlier, without backtracking on earlier claims about realizing quick cash from the Permian.

At that point, investors would have been justified in believing that ExxonMobil had unlocked a secret that no other oil and gas producer had managed to achieve—quickening the pace of its fracking operations, while also producing positive cumulative free cash flows within three years of its initial investment.

However, true to form for the fracking sector, we estimate that the negative cash flows for ExxonMobil's Permian fracking operations continued steadily through 2019, just as they had over the previous two years. Yet it was only in November of 2019—with the third anniversary of ExxonMobil's big Delaware Basin purchase looming, and the deadline for "short-cycle" Permian cash goal quickly approaching—that ExxonMobil started to retreat from its quick-cash claims for the Permian. In a speech in Midland, Texas, Staale Gjervik, president of ExxonMobil's fracking-focused U.S. subsidiary, announced that the company had shifted away from its short-cycle ambitions. "We're not chasing headline-grabbing initial potentials," Gjervik said, arguing that his company's efforts to generate value from the Permian "will take time, but we're confident they will bear fruit."[14]

Although ExxonMobil's abandonment of its "short-cycle" Permian target might have come as a surprise to some analysts and investors, company executives may have long seen the writing on the wall. As documented in IEEFA's June 2021 analysis of production from ExxonMobil's Permian wells, the productivity of ExxonMobil's fracked wells in the Delaware Basin started to decline after the initial successes of 2018, while the company's fracked wells in the Midland Basin were never top performers.[15] ExxonMobil was no doubt keenly aware of the disappointing financial returns from its U.S. upstream division (Figure 1), which included its Permian

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[13] ExxonMobil. ExxonMobil to increase, accelerate Permian output to 1 million barrels per day by 2024. March 5, 2019.
[14] Midland Reporter-Telegram. XTO president: Permian Basin now requires new approach. November 6, 2019.
[15] IEEFA. ExxonMobil: Permian Leader or Just Another Fracker? June 2021.

results. And while ExxonMobil does not release cash details by basin, it is likely that the company continued to burn through cash in the Permian. From the date of ExxonMobil's headline-grabbing entry into the Delaware Basin to the date of Gjervik's speech, we estimate that newly drilled Permian horizontal wells operated by ExxonMobil produced almost $1.8 billion in negative free cash flows—meaning cumulative drilling and completion costs for these wells exceeded their net oil and gas revenues by $1.8 billion (See appendix). This was, of course, on top of the $5.6 billion in stock plus additional cash payments that ExxonMobil made to secure the Delaware acreage in the first place.

The vision of "short-cycle" cash from fracking proved to be a mirage for ExxonMobil, just as it had for virtually every other operator since the dawn of the fracking boom. For years, business journalists had chronicled the failure of the nation's frackers to generate cash, despite their prodigious success in producing oil and gas. In December 2017, the *Wall Street Journal* published an article with the damning title, "Wall Street Tells Frackers to Stop Counting Barrels, Start Making Profits," which pointed out that since 2007, oil companies had spent $280 billion more on shale investments than they had generated by selling oil and gas.[16] In the following years, the newspaper published a slate of articles pointing out the fracking industry's financial struggles, particularly its inability to generate free cash flows.[17] And in his 2020 book, *The New Map: Energy, Climate, and the Clash of Nations*, Pulitzer Prize-winning author and oil industry guru Daniel Yergin described the conundrum faced by the U.S. fracking sector—the financial bust without the production boom:

> "What has happened since the drilling of the [the first fracked well] is extraordinary. The world has never before seen anything like the speed or scale of the growth … Yet even as U.S. oil output continued to surge, a new challenge had emerged. The shale revolution was in search of a new revolution—this one based not on technological breakthrough, but on its economics.
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> "In contrast to traditional wells, the output of shale wells, as noted earlier, falls significantly after the first year or so before leveling out. Thus companies constantly drill new wells to compensate for the declines in their previous ones … [G]rowth was no longer enough … Investors wanted money back; they wanted a return on their investments. When investors looked at

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[16] The Wall Street Journal. Wall Street Tells Frackers to Stop Counting Barrels, Start Making Profits. December 13, 2017.

[17] The Wall Street Journal. Oil's Tumble Threatens U.S. Shale Drillers. November 26, 2018. Also see: The Wall Street Journal. Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast. January 2, 2019; The Wall Street Journal. Frackers Face Harsh Reality as Wall Street Backs Away. February 24, 2019; The Wall Street Journal. Frackers, Chasing Fast Oil Output, Are on a Treadmill. April 8, 2019; The Wall Street Journal. Lower Crude and Gas Prices Take Toll on Big Oil Profits. August 5, 2019; The Wall Street Journal. Oil and Gas Bankruptcies Grow as Investors Lose Appetite for Shale. August 30, 2019; The Wall Street Journal. Oil Prices Set to Climb? Investors Aren't Betting on It. October 20, 2019; The Wall Street Journal. U.S. Oil's Growth Challenges Investors. November 10, 2019; The Wall Street Journal. Frackers Prepare to Pull Back, Exacerbating a Slowdown in U.S. Oil Growth. November 11, 2019; The Wall Street Journal. Manufacturers Face New Threat From Fracking Slump. November 18, 2019; The Wall Street Journal. Are Oil-and-Gas Companies a Good Investment? November 19, 2019.

> the shale companies, it was no longer growth at any cost but rather growth at what cost. As share prices declined, companies were forced to reset their businesses, get their spending under control, and live within their budgets—and thus deliver returns to investors either in the form of dividends or share buybacks."[18]

ExxonMobil's experience in the Permian encapsulates these lessons.

We estimate that ExxonMobil's Permian cash burn continued through late 2020. Ironically enough, as the COVID crisis raged and the company slashed its U.S. upstream capital budget, the company may have achieved several consecutive months of modest positive cash generation from the Permian in late 2020—not due to improved market conditions, but simply to an easing of its aggressive growth targets and a reduction in spending on new wells. ExxonMobil made slower Permian growth official in February 2021, with a new, diminished target of 700,000 barrels of daily production from the Permian by 2025—which was 300,000 barrels lower and one year later than its earlier goal.[19] Yet it hasn't completely abandoned its "short-cycle" claims for the Permian; as recently as its most recent quarterly earnings call in early August, the company once again touted "the advantaged short-cycle development profile of the Permian."[20]

In truth, ExxonMobil may never have been in a position to reach all of its ambitions for rapid production growth, quick cash generation, and long-term profitability at the same time. At best, it would have to pick and choose among them. In practice, we now know with certainty that all of these goals were unachievable simultaneously, and we don't yet know whether any of them are achievable at all. ExxonMobil has now fully abandoned its most aggressive goals both for production and cash, but still clings to its profitability target. However, the company's track record regarding both candor and performance leaves ample room for doubt about the company's remaining Permian ambitions.

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[18] Daniel Yergin. *The New Map: Energy, Climate, and the Clash of Nations*. United Kingdom: Penguin Books Limited, 2020.
[19] ExxonMobil. Fourth Quarter 2020 Results. February 2, 2021.
[20] The Motley Fool. ExxonMobil (XOM) Q2 2021 Earnings Call Transcript. July 30, 2021.

Methodology Appendix: Cash Flow Estimates From Permian Wells

IEEFA analyzed ExxonMobil's horizontal wells in the Permian basin drilled from January 2017 through December 2020 using the IHS Markit Dynamic North America (DNA) data system.

For each well in the DNA dataset, IHS Markit collects detailed data on the location, drilling processes, well length, drilling duration, and fracking methods used to complete the well, and the well's subsequent monthly production of oil, gas, and water. For each oil and gas play, IHS Markit also provides month-by-month estimates of the cost components of drilling and completing wells, as well as operating costs, gathering costs, the difference between local oil and gas prices and prices at major U.S. pricing hubs, royalties, severance and ad valorem taxes, and other factors affecting the economics of producing oil and gas from newly completed wells.

The DNA system uses this data to estimate free cash flows from each well in each month. Cash flow estimates incorporate estimates of one-time well drilling and completion costs, as well monthly sales revenue, operating costs, and overall cash flows from each horizontal well. To estimate cash flows over time, DNA assigns all cash capital expenditures to the first month of production from a well, and estimates monthly net realizations from the sale of oil and gas, after considering factors such as basis differentials and production taxes, but not considering corporate income taxes.

DNA's cash flow estimates focus on cash flows from wells, rather than corporate cash flows. Their well-by-well estimates do not include many of the costs of doing business as an oil and gas company, including: the cost of acquiring or securing acreage; interest and borrowing costs; hedging costs; cash gains and losses from hedging; exploration costs; and corporate income taxes. DNA may also not fully account for the economics of natural gas liquids and liquefied petroleum gases, nor of the costs of reworking existing wells.

For its analysis of cash flows from ExxonMobil's Permian wells, IEEFA aggregated cash flow estimates from each horizontal well operated by ExxonMobil in the Permian basin from January 2017 through December 2020, summing both capital expenditures and estimated monthly cash realizations from sales of oil and gas produced from those wells. Cash flow data included the initial capital cost of drilling and completing the well, as well as net cash realizations from oil and gas sales.

Note that IHS Markit tracks wells by operator, but does not track fractional ownership interests in individual wells. In this report, IEEFA's analysis aggregates cash flows for all wells operated by ExxonMobil, although some costs and revenues may have been shared with other equity owners in some wells.

IEEFA has compared DNA cash flow estimate with corporate-level cash flow data from quarterly and annual financial filings for several fracking-focused companies. In general, we have found that corporate cash flows, as reported in audited financial reports, are significantly lower than the narrower cash flows from the wells that the companies operate, as estimated by the DNA system. Some differences reflect corporate costs, such as interest and borrowing costs, that the DNA system does not track. Others reflect shared ownership of wells operated by the company, which may dilute cash flows across multiple equity owners. These differences are not shortcomings of the DNA cash flow estimation system, but instead reflect the fact that the DNA system is designed to measure well-by-well economics rather than corporate-level finances.

ExxonMobil's internal financial results from its Permian operations may differ significantly from IEEFA's estimates. Some of those differences could potentially favor ExxonMobil; for example, the company may have found ways to drill and complete wells at a lower total cost than IHS Markit estimates. At the same time, IEEFA's presentation of cash flow results in this report ignore ExxonMobil's corporate costs, including as much as $6.6 billion spent to acquire Delaware Basin acreage in January 2017.

Cash flow estimates in the report only cover wells that were brought into production from January 2017 through December 2020 and that IHS Markit designated as having achieved a production peak, based on data updated as of July 5, 2021. Preliminary data suggest that positive free cash flows from ExxonMobil's horizontal Permian wells likely continued through the first quarter of 2021.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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