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Oil Market Outlook: Getting Ahead of the Narrative

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THE CARLYLE GROUP | 1001 PENNSYLVANIA AVENUE, NW | WASHINGTON, DC 20004-2505 | 202-729-5626 | WWW.CARLYLE.COM

Oil Market Outlook: Getting Ahead of the Narrative

By Jason M. Thomas

The sharp rebound in Brent crude prices and energy industry earnings over the past year has done little to dislodge the "lower for longer" narrative that continues to pervade oil market discussions and depress industry valuations. While the recent increase in fuel prices has attracted consumers' attention, skeptical capital markets remain focused on booming "short-cycle" production in the U.S. and the potential rise of electric vehicles and related technology.

Capital markets' skepticism of the recent market rally seems predicated on three misperceptions. First, oil production capacity is not increasing. Exploration and production (E&P) investment plunged with oil prices in 2015-16 and the rebound observed over the past year has been overwhelmingly concentrated in "short-cycle" production in the U.S. that may not add meaningfully to long-term production. New discoveries of conventional oil and gas stand at 60-year lows.

Second, the combined effects of electric vehicle adoption and new climate-based regulations are quite small relative to industry decline rates. Demand for crude is likely to increase over the next decade.[1] Even if one assumes the most rapid plausible growth in EV sales and emission reductions that go far beyond those in The Paris Agreement, crude supply would still decline at a much faster rate than crude demand. Natural resource depletion compounds the upside price risks posed by the weakness in E&P investment.

Third, energy companies, particularly those in the E&P subsector, have re-engineered processes and technology to boost production, lower per barrel costs, and become more profitable at lower prices. Recent data indicate that the industry is likely to prove more profitable at $75 per barrel crude today than it was at $100 crude in 2013-14.[2] Capital markets have failed to account properly for companies' increased profitability at lower prices, with the industry's consolidated enterprise value close to 8x trailing five years' Ebitda compared to 14x for the corporate equity market as a whole.[3]

Absent a significant pick-up in E&P investment, supply constraints could emerge over the next few years that send oil prices spiraling upwards. That is especially true if the market experiences a supply disruption in Iran, Russia, Venezuela, Nigeria, Libya, or another exporter due to the re-imposition of sanctions, economic collapse, or some other geopolitical event. Exacerbating this scenario is the fact that OPEC's spare capacity has declined steadily over the past 18 months, and is set to decrease further as the group implements the supply boost agreed upon in June. In the event of a global supply shock, OPEC will be hard-pressed to cover any shortfall, raising upside risk to prices. Prior supply shocks of this type have generally resulted in price spikes of 81%, on average, and futures prices have historically incorporated a premium to compensate for the risk of a similar event in the future.[4] Today, the market appears especially complacent, with minimal spare capacity, lots of geopolitical risk, and little-to-no premium for bearing it.

While energy companies would certainly benefit from such an outcome, they do not depend on it, having spent much of the past two years adjusting to life at $50 per barrel crude.

1. The Feedback Between Crude Prices and E&P Capex

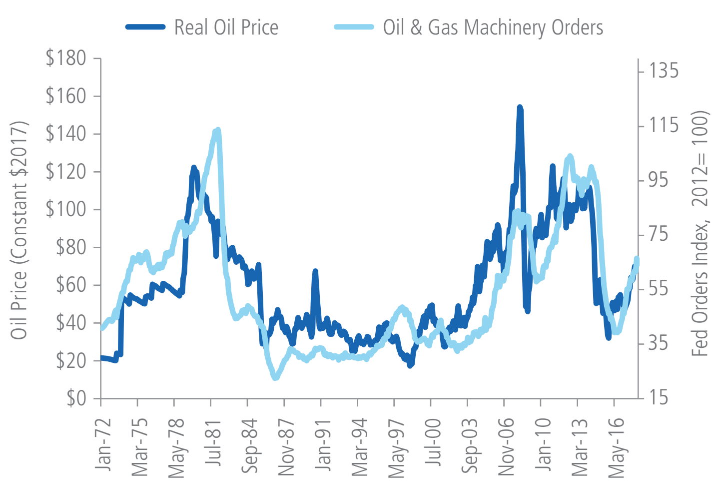
The per barrel price of oil is among the most volatile of all economic time series, with an average annual variation of 27%, about one-and-a-half times that of stocks (as measured between 1972 and June 2018).[5] Yet, popular discussions of oil prices often overlook this volatility in favor of market narratives that tend to assume tomorrow will look much like today.

When oil prices were at record highs a decade ago, observers expected prices to remain elevated indefinitely due to the intersection between rapid Asian demand growth and "peak" conventional oil production.[6] After oil prices collapsed in 2014-16, "peak demand" took the place of "peak oil" in popular press accounts as observers swiftly coalesced around a new narrative: prices would remain low over any relevant forecast window because of the supply glut from the unconventional oil boom and the unremitted rise of electric vehicles and conservation policy.[7]

These market narratives are not wrong so much as myopic, and it is precisely this myopia that gives rise to the cyclicality in exploration and production (E&P) spending at the heart of oil price cycles.

FIGURE 1

Real Oil Prices and E&P Capex[8]



The volatility in oil prices reflects the volatility of E&P investment. Monthly data since 1972 reveal an 80% correlation between the real price of a barrel of Brent crude and E&P equipment orders (Figure 1). High oil prices generate a surge in *real* E&P

1 Energy Information Agency, 2018 Outlook, June 2018.
2 Carlyle Analysis of S&P Capital IQ Database, July 2018.
3 Carlyle Analysis of S&P Capital IQ Database, July 2018.
4 Hamilton, J. (2008), "Understanding Crude Oil Prices," UC Energy Institute.
5 Carlyle Analysis of Federal Reserve Bank of St. Louis Data, June 2018. Volatility measured as mean absolute deviation relative to those of major stock indexes.
6 "World Oil Production Peaked in 2008," *The Oil Drum*, March 2009.
7 BP warns of price pressures from long-term oil glut, Financial Times, January 25, 2017.
8 Federal Reserve. G. 17; Federal Reserve Bank of St. Louis, June 2018.

investment (after accounting for increases in the cost of oilfield services contracts and other inputs), while low prices tend to be associated with low levels of E&P capex. A feedback loop results: E&P investment responds to today's price, but the level of investment today determines tomorrow's oil production capacity and price range.

When oil prices are high and expected to remain so indefinitely, it is relatively easy to secure discretionary risk capital for E&P projects; industry capex and related deal activity boom on the back of high expected returns. Eventually, cumulative capex pushes oil production capacity to levels that cause prices—and the market narrative—to turn. At that point, low prices depress expected returns on incremental investment as well as the cash flow of E&P companies and integrated majors, which forces them to rely more heavily on external finance at precisely the moment it's hardest to secure. Fed by the "lower prices for longer" narrative, underinvestment leads to a contraction in net production capacity. Once the resulting supply constraint binds, prices rise nonlinearly, as observed most recently in 2000 and 2007-08.

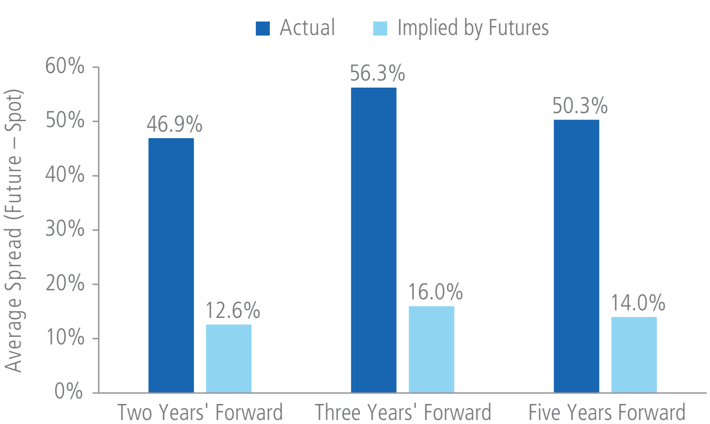
2. Futures Prices are Poor Guide to the Future

One might expect that reliance on less volatile futures prices would attenuate some of the cyclicality in E&P outlays. Unfortunately, the crude oil "futures strip" rarely provides better guidance than a simple extrapolation of current spot prices. Futures prices are not the market's "forecast" for future spot prices, as commonly supposed, but simply the price at which future production can be sold forward today. As a result, futures prices are anchored to the present in ways that systematically understate the variation in oil prices likely to occur over the life of the contract.

For example, the average "spread" between the spot price and two-year futures price has been 12.6% over the past 20 years. Over the same period, the average deviation in spot prices measured two years apart has been 46.9%. Over two-, three-, and five-year horizons, oil prices have been 3.5x as volatile as would be implied by the corresponding spreads between spot and futures prices (Figure 2). By understating prospective volatility, futures prices provide mistaken support for narratives that anticipate tomorrow will look a lot like today.

FIGURE 2

Futures Prices Understate Volatility[9]



9 Carlyle Analysis; Bloomberg, Accessed June 2018.

3. Permian Not the Solution for Global Depletion

Though oil prices (+50%) and energy company earnings (+300%) have risen sharply over the past year,[10] popular press accounts continue to focus on downside price risks. The "shale glut" story remains unchanged; U.S. crude production is reaching all-time highs on the back of the Permian basin, which now produces nearly as much oil as Iran.[11] Electric vehicles, self-driving cars, ride-sharing platforms, and advances in battery technology captivate the public imagination, while climate change policy looms in the background. Why would anyone expect upside in oil given booming U.S. production and such obvious long-run headwinds to demand?

Although crude demand should rise over the next decade thanks to continued growth in Emerging Markets' consumption, energy investment is not simply about meeting future demand growth. E&P companies have to invest heavily to offset decline rates on their existing fields and to replace depleted reserves.[12] Without new investment, depletion will cause global oil *supply* to drop far more than any plausible decline in *demand* caused by electric vehicle adoption or climate policy.

While short-cycle U.S. development has rebounded sharply since the end of 2016, investment elsewhere remains depressed. Global E&P capex fell by more than 60% between 2012 and 2016, the largest cumulative peak-to-trough decline since the 1980s (Figure 1). Even when accounting for the U.S. rebound, global E&P capex remains roughly 40% below prior peaks. Less investment translates to fewer discoveries of new conventional oil and gas reserves, which have declined by 77% over the past five years and now stand at the lowest absolute levels since the 1940s.[13]

Discoveries have been even weaker than would be implied by the absolute level of capex because a larger share of E&P investment has been focused on short-cycle production in the U.S. Integrated majors like Chevron and Exxon have become the largest investors and drillers in the Permian basin.[14] More than half of all new production over the next five years will come from the U.S., and almost all of that will come from the Permian.[15]

U.S. light tight oil (LTO) production can grow to meet short-run demand but it is not a suitable replacement for large-scale conventional development due to steep decline rates. Large conventional fields have a build-up and plateau phase where oil production rises or remains unchanged. For example, Prudhoe Bay peaked in 1989, twelve years after it began production. Upon reaching maturity, production at mature fields begins to decline at an annual rate of 9% per year, on average, which can be attenuated by incremental drilling and investment.[16]

By contrast, U.S. LTO wells often generate massive initial production, but production per well declines immediately and often at exponential rates.[17] The "effective duration" of the production per well is much shorter, which is good from an

10 Carlyle Analysis, S&P Capital IQ Database, June 2018.
11 Drilling Productivity Report, EIA, June 2018.
12 Hook, M. et al. (2009), "Giant Oil Field Decline Rates and their Influence on World Oil Production," *Energy Policy*.
13 Rystad Energy, "All Time Low for Discovered Resources in 2017," December 2017.
14 Pump the Permian, Bloomberg, April 27, 2018.
15 IEA forecast, 2018.
16 IEA, 2015 Oil Market Report.
17 Energen, "Accelerating Growth in the Permian Basin," February 2017.

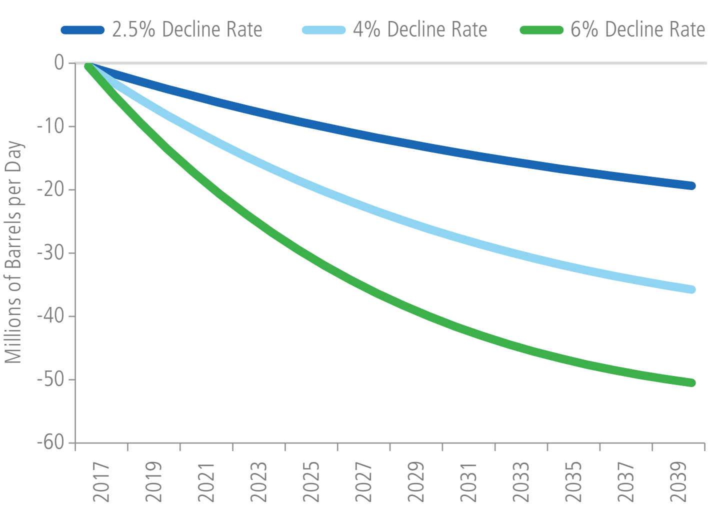
investment perspective as more revenues occur sooner in time, but not helpful to longer-run oil production capacity. More new wells are required to offset production declines from legacy wells, which leads to concerns about the impact of tighter spacing and interference. Production can also grow beyond levels that can be accommodated by existing pipeline infrastructure. At some point in the next decade, it may be difficult for incremental LTO production at new wells to keep up with depletion at legacy wells, causing U.S. production to plateau and eventually decline.[18]

When accounting for fields in build-up and plateau phases, the weighted average global decline rate ranged between 4% and 4.5% prior to the LTO boom.[19] As LTO accounts for a growing share of global output, average decline rates increase because a larger percentage of global production is in the decline phase and the average decline rates at such wells increases. Relative to a pre-shale average of 4.5%, global decline rates are likely to rise to 6% per year by 2022.

To put these decline rates in context, consider that the most aggressive assumptions for fuel conservation would yield a 1.2% annualized decline in demand, or 74 million barrels consumed per day in 2040, down from 98 million in 2017.[20] This scenario assumes the most rapid plausible transition to electric vehicles and climate regulations far beyond the scope of the national pledges made as part of The Paris Agreement. Yet, by 2040, the supply lost from the cumulative impact of depletion would exceed this decline in demand by 50 million barrels per day (Figure 3). More conservative decline rate estimates still yield large net production shortfalls over the 2018-2040 period when measured against this worst-case demand scenario.[21]

FIGURE 3

Production Shortfall from Depletion Relative to Worst-Case Demand Scenario[22]



18 EIA, 2018 Annual Energy Outlook.

19 Sorrell, S. et al. (2012), "Shaping the global oil peak: A review of the evidence on field sizes, reserve growth, decline rates and depletion rates," *Energy.*

20 "Future Oil Demand Scenarios," World Economic Forum, April 2016. This scenario assumes a reduction in crude oil demand sufficient to keep global temperatures from rising 3 degrees Celsius.

21 The IEA estimates that the decline rate at existing mature oil fields dropped to just 5.7 percent in 2017, down from about 10 percent in 2011 and 7.5 percent as recently as 2016. For the period of 2010-2014, the decline rate at mature oil fields averaged 7 percent. Bank of America Merrill Lynch states that decline rates for conventional fields outside of OPEC have risen this decade from 4.87 percent to 5 percent.

22 Carlyle Analysis; Energy Information Administration, "Short Term Energy Outlook," June 2018.

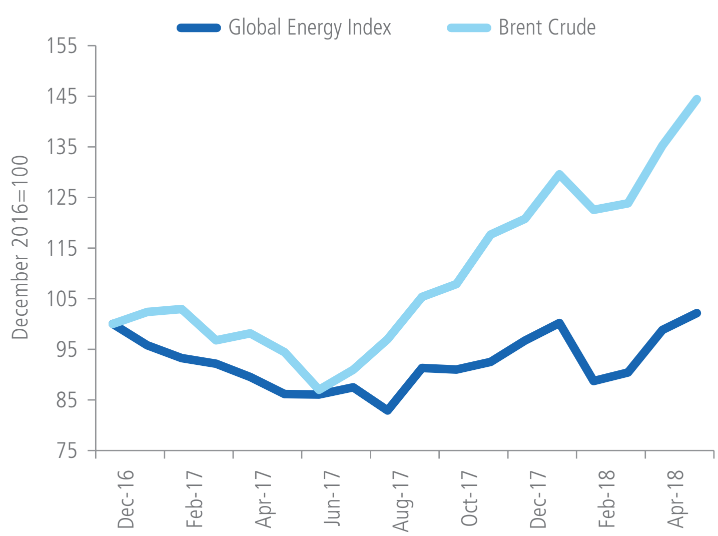
4. Low Price Narrative Capitalized into Energy Sector Valuations

The "lower for longer" narrative continues to be reflected in energy sector valuations. Since the end of 2016, Brent crude has outperformed energy stocks by 40 percentage points, on average (Figure 4). The consolidated enterprise value of the energy sector is now barely 8x trailing five years' Ebitda and just 6x 2013 Ebitda. By comparison, the consolidated enterprise value of U.S. businesses stands at 14.6x trailing five years', and 15.6x 2013 Ebitda, respectively.[23] This valuation gap implies that any upside in oil prices over the next three to five years comes entirely free of charge, including a spike caused by a geopolitical event or related uncertainty.

Of course, energy company earnings are not solely determined by the price of energy. Businesses have the capacity to boost profits by increasing the barrels per day produced in a given field or reducing the average cost of producing a barrel. The 2015-16 price shock and power of the "lower for longer" narrative provided impetus for management teams to pursue new technologies and cost reduction strategies that might not have otherwise existed had crude prices remained high.

FIGURE 4

Energy Stocks Lag Brent Crude by 40% Since End of 2016



Many operators re-engineered their processes and technologies to turn profits at $50 per barrel instead of $100.[24] Industry-wide operating margins have widened by 24% since the 2016 lows and the aggregate Ebitda of E&P companies has been 20% higher than one would expect at current oil prices.[25] At the same time, technology has reduced drilling costs, which increases capital efficiency, or the ratio of operating income per dollar of capital invested. These data imply that many players in the industry have positioned themselves to be far more profitable at $70-$75 per barrel oil this year than they were when oil exceeded $100 per barrel in 2013-14.

23 Carlyle Analysis of S&P Capital IQ Database, July 2018.

24 "Oil Companies at Last See Path to Profits After Painful Spell," The New York Times, August 1, 2017.

25 Current Ebitda margin as measured relative to the 2013 average. S&P Capital IQ, June 2018.

5. Getting Ahead of the Narrative

Despite the sharp rebound in crude oil prices, valuations imply that capital markets remain skeptical of the industry's long-run fundamentals. This skepticism feels misplaced. Current valuations fail to account for productivity gains and cost savings that allow more companies to operate profitably at much lower crude prices. These valuations also ignore the upside price risks posed by geopolitics and cumulative underinvestment. When supply constraints bind—because of either an unplanned supply disruption or insufficient spare capacity to meet incremental demand—prices tend to rise nonlinearly to equilibrate markets. While futures prices have historically incorporated a premium to compensate for supply risks tied to geopolitical events, there is little evidence of one today.

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Jason M. Thomas is a Managing Director and the Director of Research at The Carlyle Group, focusing on economic and statistical analysis of the Carlyle portfolio, asset prices, and broader trends in the global economy. He is based in Washington, D.C.

Mr. Thomas serves as the economic adviser to the firm's corporate private equity and real estate investment committees. His research helps to identify new investment opportunities, advance strategic initiatives and corporate development, and support Carlyle investors.

Previous to joining Carlyle, Mr. Thomas was Vice President, Research at the Private Equity Council. Prior to that, he served on the White House staff as Special Assistant to the President and Director for Policy Development at the National Economic Council. In this capacity, he served as the primary adviser to the President for public finance.

Mr. Thomas received a B.A. from Claremont McKenna College and an M.S. and Ph.D. in finance from George Washington University where he studied as a Bank of America Foundation, Leo and Lillian Goodwin Foundation, and School of Business Fellow.

He has earned the Chartered Financial Analyst (CFA) designation and is a financial risk manager (FRM) certified by the Global Association of Risk Professionals.

CONTACT INFORMATION

Jason Thomas
Director of Research
jason.thomas@carlyle.com
(202) 729-5420