Illuminate

ANALYSIS THAT REVEALS

JANUARY 2017

OIL MARKET COMMENTARY:

Where the Past Is—and Is Not—Prologue

THE CARLYLE GROUP

GLOBAL ALTERNATIVE ASSET MANAGEMENT

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

Where the Past Is—and Is Not—Prologue

By Jason M. Thomas and Chris G. Carter

Since demand for oil-based fuels persists continuously through time as cargo and people are transported across the globe, the spot price of oil generally moves in response to relatively small shifts in supply. In real-time, these supply adjustments occur through changes in inventory levels and producers' spare capacity. But because of the large fixed costs and significant lead times required to bring most types of undeveloped crude to market, the supply adjustments we observe today necessarily depend on *past* spending on exploration, development, and technology. Likewise, today's investment decisions will determine the extent to which *future* oil supply can adjust to meet future demand.

Global exploration and development spending generally varies in response to crude oil prices. Oil price busts tend to be self-correcting, as low prices depress investment, which reduces future supply and plants the seeds for future price increases. While global exploration and development spending has indeed collapsed since 2014, the effective "spare capacity" of independent North American operators may reduce the risk of a sharp near-term rebound in prices.

U.S. oil and gas companies have become a "swing producer" in global oil markets, with large volumes of incremental oil production that can be brought to market in relatively short order.[1] In 2016, U.S. oil production began increasing once prices exceeded $45 per barrel; any increase in 2017 spot prices from current levels is likely to elicit a U.S. production response from undrilled horizontal locations that dampens price volatility.

Yet the U.S. accounts for just one-tenth of global crude oil production. The sharp decline in global exploration and development spending over the past two years means that capacity outside of North America may be declining, as the depletion of existing fields exceeds the development of new reserves. Declining capacity raises the possibility of binding future supply constraints of the sort that have generated nonlinear price increases in the past. The timing of such price instability is anyone's guess, but as history can attest, it can arrive sooner than most market participants thought possible.

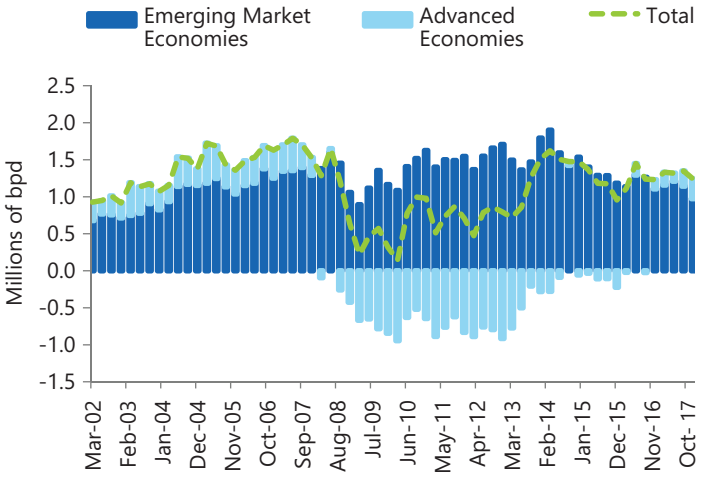
OPEC Production Cuts and the Near-Term Outlook

At its November 30, 2016 ministerial meeting, OPEC agreed to reduce oil output by 1.2 million barrels per day (bpd) and received commitments soon thereafter from 11 non-OPEC nations, including Russia and Mexico, to reduce output by an additional 0.6 million bpd.[2] In conjunction with this announcement, Saudi Arabia's Energy Minister signaled that the Kingdom planned to cut its production below the agreed upon target, which could reduce supply by an additional 0.1 million bpd.

The collapse in crude oil prices has taken a significant toll on OPEC economies, which have seen their combined current account balance shift from an annual surplus of more than $400 billion in 2012 to a $150 billion deficit in 2016.[3] These agreements aim to "balance" the market and place a floor under the spot price of crude oil. Since the end of 2013, oil supply has exceeded market demand, causing total petroleum inventories to grow by an estimated 600 million barrels.[4] OPEC ministers and their non-OPEC counterparts believe that these output cuts should cause global inventories to peak in the middle of 2017 and begin to decline thereafter.

FIGURE 1

Average Annual Growth in Global Oil Consumption (Millions of bpd)[5]



The scale of OPEC's planned production cuts are based on the assumption that global oil consumption will increase by 1.2 million bpd in 2017. While an unforeseen macroeconomic shock could depress near-term demand growth, this forecast looks quite reasonable, as global oil consumption has grown at an average annual rate of 1.2 million bpd for the past 20 years. When measured over five-year windows, the average annual growth of oil demand has been remarkably stable, ranging between 0.6 million bpd and 1.6 million bpd over 92% of the time. As shown in Figure 1, nearly all of the incremental consumption over the past 20 years has occurred in Emerging Market (EM) economies, where annual demand growth has exceeded 1 million bdp in 19 of the past 20 years (measured on a five-year rolling average basis).

The recent agreement represents a reversal of past OPEC policy, which sought to boost production in response to the competitive threat posed by North American oil and gas. Between the end of the Great Recession and the middle of 2014, North American petroleum output increased by

1 While the U.S. may not meet the classic criteria of a "swing producer," it has demonstrated the ability to generate market-altering production swings over short periods.

2 See: http://www.opec.org/opec_web/en/press_room/3912.htm; and http://www.opec.org/opec_web/en/press_room/3912.htm

3 IMF, 2016 WEO Database.

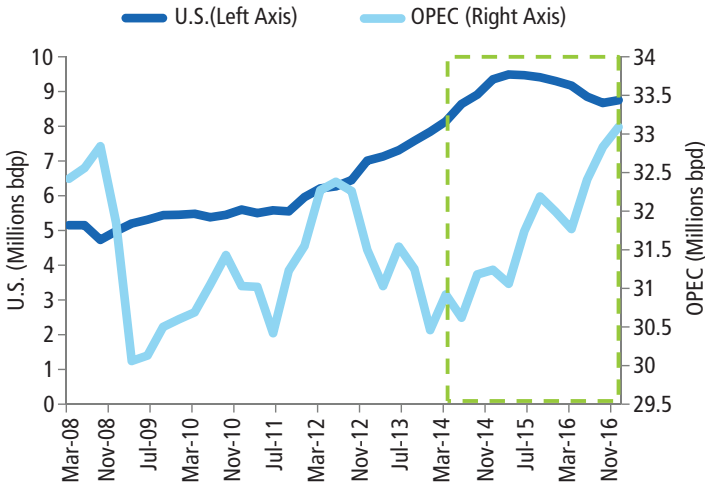
4 Carlyle, OECD, and EIA Inventories Data, Jan 2017.

5 EIA, Petroleum and Other Liquids, Jan 2017.

nearly one million bpd per year while OPEC production remained roughly flat (Figure 2). OPEC responded by boosting its production by over two million bpd between the middle of 2014 and the end of 2016. Total OPEC crude oil production now stands at nearly 33.1 million bpd, roughly 5% above its trailing five year average.

FIGURE 2

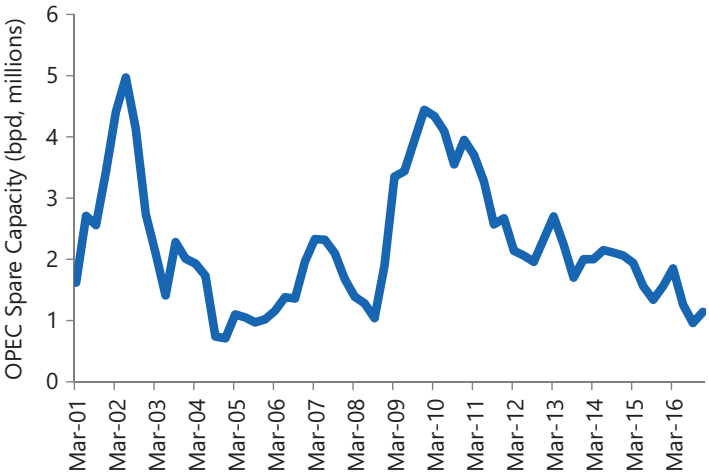
Crude Oil Output (Millions of bpd)[6]



The November 2016 agreement should help to stabilize crude prices, but rhetoric may be running somewhat ahead of the reality at this point. Even if fully adhered to by OPEC members—a strong assumption given enforcement challenges—the proposed supply reduction would still leave OPEC output 1.8% *above* its five-year average, with OPEC spare capacity slightly *below* its 15-year average (Figure 3). And even if the cut succeeds at balancing the market, a significant stock overhang will remain, at least in the short-run, with inventories in advanced economies like the U.S. and Europe nearly 15% above their pre-2015 average.[7]

FIGURE 3

OPEC Spare Capacity (Millions of bpd)[8]



6 Energy Information Administration, Petroleum and Other Liquids, December 2016.
7 Energy Information Administration, OECD Inventory per Daily Consumption, December 2016.
8 Energy Information Administration, Petroleum and Other Liquids, December 2016.

Underestimating North American Operators, Then and Now

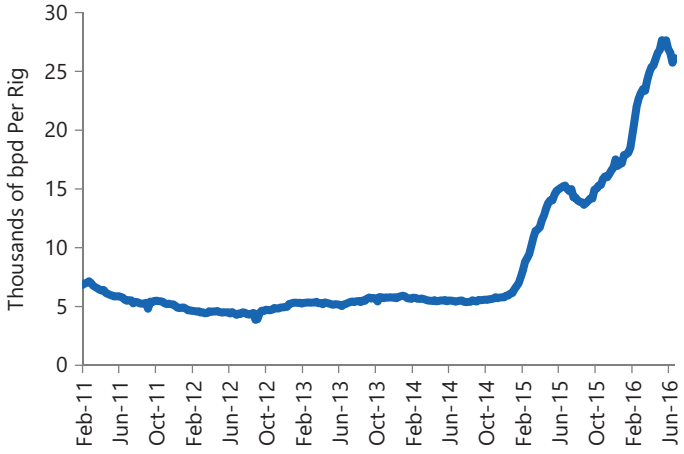
OPEC reversed course because of the surprising resiliency of North American crude oil production. It was widely believed that the rapid depletion rates of tight oil (decline rates of 60% or more in the first year) required steady investment in new fields to replace lost output. If increases in OPEC output could push oil prices below "breakeven" levels of roughly $60 per barrel, new investment would cease, causing North American tight oil production to drop exponentially and preserving OPEC's dominant market position.[9]

While the 2014 OPEC production surge succeeded in driving prices to levels that bankrupted some operators and made investment uneconomic in some basins, the total decline in U.S. crude production proved to be quite modest. The peak-to-trough decline in U.S. crude oil production was just 0.9 million bpd (-9.5%). When including liquids, North American petroleum production dropped by just 0.5 million bpd (-2.3%). North American tight oil producers were able to survive the negative price shock thanks to increased focus on certain low-cost basins, significant gains in productivity, and a sharp decline in the cost of drilling, completing, and operating unconventional wells.[10]

When oil prices collapsed, operators shifted from rapid expansion and "Greenfield" development to a more defensive posture of maximizing output and efficiencies from existing "core" basins.[11] The shift in operators' focus led to a quadrupling in the amount of oil generated per rig in operation (Figure 4) and a marked improvement in single-well drilling economics. Much of this improvement has been driven by technological innovation, including the use of longer laterals, advancements in the type and volume of proppant and fluid used in fracking, and enhancements in seismic imaging and reservoir performance modeling.[12]

FIGURE 4

U.S. Crude Oil Production per Oil-Directed Rig in Operation[13]



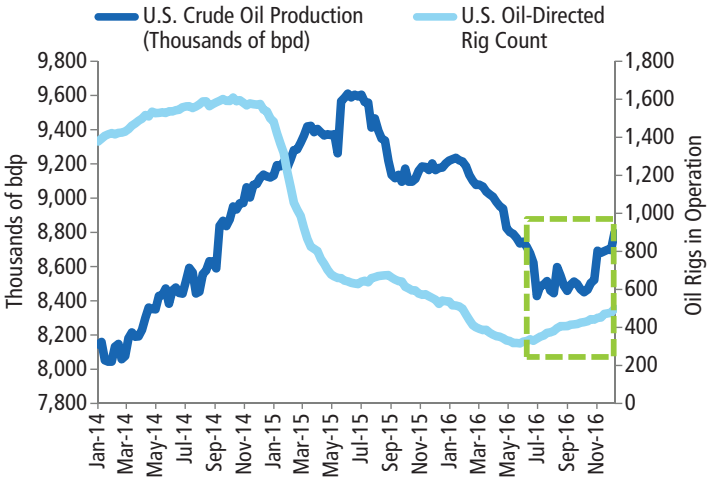
9 Kleinberger, R. et al. (2016), "Tight Oil Development Economics: Benchmarks, Breakeven Points, and Inelasticities," MIT Center for Energy and Environmental Policy Research.
10 EIA, Petroleum and Other Liquids, Jan 2017.
11 McKinsey, "Why has light tight oil production proven so resilient in the Permian?" September 2016.
12 McKinsey, 2016.
13 Energy Information Administration, Petroleum and Other Liquids, December 2016.

The slowdown in development drilling throughout North America curtailed demand for oil-field services like contract drilling and hydraulic fracturing. With service capacity static or declining, service providers had no choice but to accept the renegotiation of existing service contacts. Lower service costs reduced U.S. breakeven oil prices by 25% between October 2014 and September 2015.[14] This experience also highlighted that the cost of a barrel of oil often depends on the price of oil—not the other way around, as is commonly supposed.[15]

Just as OPEC in 2014 underestimated the extent to which North American production could be maintained at low oil prices, analysts today may fail to appreciate the volume of production that could be brought online quickly if oil prices rise from current levels. According to the Energy Information Administration (EIA), U.S. oil production is already increasing, with year-end output up 0.35 million bpd (+4.1%) relative to October 2016 (Figure 5). With domestic crude prices averaging just $48 per barrel during this rebound, the effective "breakeven" price for a large swath of unconventional oil appears to be well below $50. This supply response also suggests that U.S. production could once again rise at an annual rate of more than one million bpd should oil prices rise meaningfully from current levels.

FIGURE 5

U.S. Crude Oil Production and Rig Count[16]



Our favorable outlook for U.S. production is, in large part, based on the substantial increase in the marginal productivity of capital allocated to the sector. The rise of horizontal drilling—which now accounts for 81% of U.S. rigs—allows operators to exploit longer laterals and multiple oil-producing formations "stacked" on top of each other. The thickness of the shale in the Permian basin, for instance, has been equated to ten or eleven EagleFord shale formations located on top of one another.[17] The cost of developing a section of land in the basin has risen nearly 5x, but these outlays generate almost 10x as much oil (See comparison of Vertical and Horizontal Drilling Economics in Table 1).

Ten years ago, when 90% of U.S. rigs were vertical and directional, a 640 acre section in parts of the Permian Basin could support 16 vertical wells, which could be expected to generate 2.4 million barrels of oil equivalent (Boe). At an average cost of $2 million to drill and complete each well, an operator's finding and development cost would be roughly $17.78 per Boe. Today, an operator can use horizontal drilling to develop each stacked layer from a single surface location, which could generate a five-fold increase in effective acreage and reduces the cost per Boe to $8.89.

TABLE 1

Illustrative Midland Permian Basin DrillingEconomics[18]

Drilling Locations	Vertical	Horizontal
Acres Per Section (1)	640	640
# of Unique Prospective Benches	NA	5
Effective Acres Per Section	640	3,200
Well Spacing (Acres Per Well)	40	107
Wells Per Section	16.0	30.0
Drilling & Completion CapEx		
D&C CapEx Per Well ($mm)	$2.0	$5.0
x Wells Per Section	16.0	30.0
D&C CapEx Per Section ($mm)	**$32.0**	**$150.0**
Gross Reserve Recovery		
Gross EUR Per Well (MBoe)[18]	150	750
x Wells Per Section	16.0	30.0
Gross EUR Per Section (MMBoe)	**2.4**	**22.5**
Finding & Development Cost		
Gross Single Well EUR (MBoe)	150	750
x (1- Royalty Burden)	75%	75%
Net Single Well EUR (MBoe)	113	563
Net F&D Cost ($/Boe) (2)	**$17.78**	**$8.89**

Global Spare Capacity is Declining

The large volume of oil effectively stored underground in the core U.S. basins should help to dampen the near-term volatility of oil prices. But it would be a mistake to expect prices to remain range bound indefinitely. The U.S. accounts for just 10% of global oil production and its "spare capacity" may prove to be of little comfort should a geopolitical crisis trigger a major supply disruption. Recent data suggest productive capacity outside of North America may be declining. With average lead times of three-to-five

14 Kleinberger, R. et al. (2016), "Tight Oil Development Economics: Benchmarks, Breakeven Points, and Inelasticities," MIT Center for Energy and Environmental Policy Research.
15 Kleinberger, R. et al. (2016).
16 Energy Information Administration, Petroleum and Other Liquids, December 2016.
17 "The Permian Basin Oil Play: 'Unleashed,' Oil & Gas Investments, April 2012.

18 For Illustrative Purposes Only. Assumes 100% Working Interest and a 25% Royalty Burden. (1) A section is defined as one square mile; (2) F&D calculated as D&C capex per well divided by the net single well EUR.
19 EUR is Expected Ultimate Recovery.

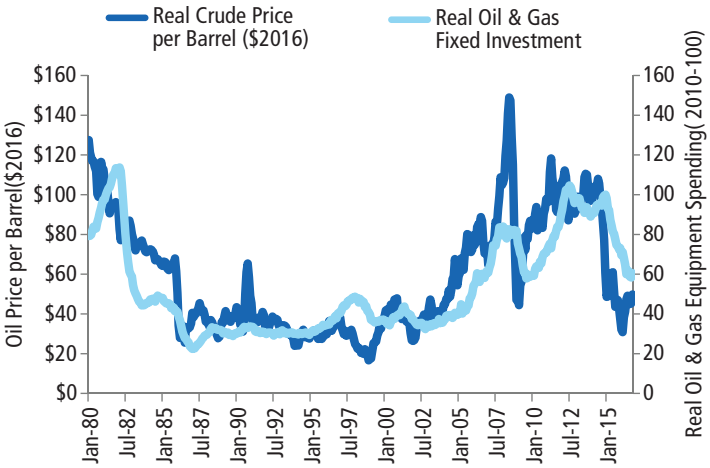
years between discovery and production of new fields, the lack of exploration and developing spending today raises the prospect of binding supply constraints in the future.[20]

The spot price of oil is an extraordinarily volatile time series, with an average absolute change in annual prices of more than 25%.[21] While these price swings are often due to unplanned supply disruptions caused by natural disaster or geopolitical crises, most of the volatility can be attributed to two key market features: (1) the long lead time associated with most oil development projects; and (2) the tendency for development spending to rise and fall predictably in response to current spot prices. As a result, the price of oil fluctuates in response to the *net* investment cycle, which reflects a "tug of war" between development spending and the depletion of existing reserves.[22]

As shown in Figure 6, since 1980 there has been an 81% correlation in monthly real oil and gas development spending globally and the real spot price of crude. High prices tend to generate a high rate of net investment, which plants the seeds for sharp declines in future spot prices as supply grows faster than demand. Likewise, low prices can result in *negative* net investment, as existing resources are depleted at a faster rate than new reserves are developed. If sustained long enough, the resulting drop in capacity can generate exponential price increases—as observed most recently in 2008—as near-term supply is incapable of rising in response to price signals.

FIGURE 6

Real Crude Oil Prices and Real Oil & Gas Investment Spending Globally[23]

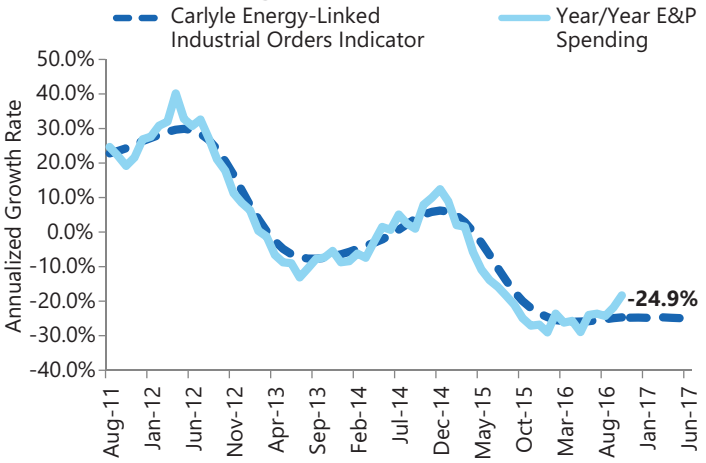


The recent oil price bust led to a predictable collapse in global exploration and development spending. Since 2014, development spending declined by more than 40% in real terms and more than 55% when accounting the decline in the prices of equipment and services.[24] This decline is already larger than those that occurred following the Global Financial Crisis (2009) and Asian Financial Crisis (1999) and is exceeded only by the drop in investment observed in the mid-1980s.

There is little reason to suspect investment will snap back in the near future. While oil prices rebounded by nearly 40% in 2016, exploration and development spending continued to decline. Carlyle's industrial portfolio proxy for energy-related equipment orders suggests oil and gas capex continues to fall at 24% annual rate (Figure 7), despite being down 47% from its 2014 peak. Corporate exploration and development budgets remain under severe strain, with very little delineation or extending and virtually no appetite among investors or operators for the large, capital-intensive projects so critical to long-run capacity outside of North America. Total planned upstream capital spending has now declined by $2 trillion through 2019.[25]

FIGURE 7

Carlyle Economic Indicator: Global Energy-Related Equipment Spending[26]



Futures Prices Do Not Predict the Future

The possibility of a sudden upward move in the spot price of oil is nowhere reflected in oil futures markets, where the five-year futures contract is priced at $55.[27] The futures curve is not "the market's" expectation for the likely evolution of spot prices, but simply the price at which producers can sell today's production at some date in the future.[28] Futures prices tend to closely track the spot price as it moves up and down through time, with 97% of the variation in the two-year futures contract (and nearly 76% of that of the five-year contract) explained by shifts in the spot price of crude.[29] The spread between spot and futures prices provides some guidance on the likely direction of prices, but futures prices also depend on storage costs, interest rates, and the "convenience yield" derived from using the underlying oil or pledging it as collateral for financing.[30]

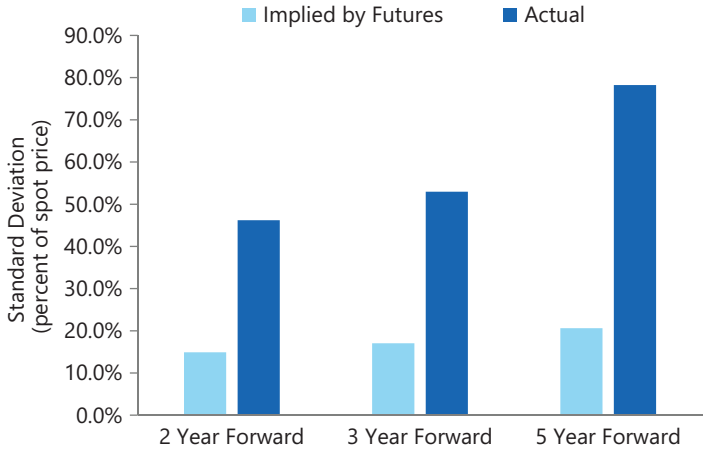
20 World Bank, *Global Economic Prospects*, January 2016.
21 Carlyle, Bloomberg data, January 2017.
22 Cuddington and Nule. (2013), "Variable Long-Term Trends in Mineral Prices: The Ongoing Tug-of-War between Exploration, Depletion, and Technological Change." Colorado School of Mines.
23 Real development spending comes from the Federal Reserve, G.17, and is measured on the basis of total industrial orders for mining and oil-field equipment received globally by U.S. manufacturers. We do not have global data, but note a nearly perfect correlation in real orders for similar equipment across other advanced economies. Equipment orders are perhaps the best global proxy for development because of many OPEC members' reliance on imported capital goods.
24 Carlyle Analysis, G.17 and Barclays.
25 IHS Markit, April 19, 2016.
26 Carlyle Analysis of Portfolio Company Data; G.17. Federal Reserve.
27 NYMEX, as of December 9, 2016.
28 C.f. Nielsen, M. and E. Schwartz, "Theory of Storage and the Pricing of Commodity Claims," *Review of Derivatives Research*, January 2004.
29 The R-squared of a log-linear regression of the futures price on the spot price for monthly data.
30 Jarrow, R. (2010), "Convenience Yields," *Review of Derivatives Research*, April 2010.

This is not to say that futures contracts provide no information about future market conditions, but simply that the future spot price can differ substantially from the corresponding futures price. To appreciate the difference, consider the spread between the realized volatility of crude spot prices over a given time horizon and the volatility implied by futures prices of the same maturity. As shown in Figure 8, futures contracts systematically understate the volatility of crude oil prices by 67%, on average, at two, three, and five-year horizons.

At $50 per barrel oil, futures markets would imply that there's a 70% chance the spot price of crude would range between $40 and $60 in five years' time. Conversely, if we were to use the historic volatility of crude prices over five years, our 70% confidence interval would widen to include all possible realizations between $11 and $89 per barrel. While this spread may seem extreme, consider the $110 rise (+360%) in spot prices in the five years' ending June 2008 or the $71 decline (-70%) observed between February 2014 and February 2016. The current futures strip also provides little-to-no compensation for geopolitical risks despite evidence of increased instability in major oil producing nations.

FIGURE 8

The Volatility of Oil Prices Over 2, 3, and 5 Year Horizons[31]



When Does the Short-Run Become the Long-Run?

The "spare capacity" of U.S. operators implies that any increases in the price of oil may be somewhat restrained in the near-to-medium term. Large volumes of oil sit underground waiting to be extracted. With $48 per barrel oil all that was required for U.S. production to begin increasing, it would not be unreasonable for domestic output to again grow at a 1 million bpd annual rate should prices rise from current levels. But several more years of relatively low prices raises the prospect that the cumulative decline in net investment outside of North America will reach levels that increase the probability of a price spike at some point in the future.

Some may argue that this time is different and a sustained price increase may never arrive because of the advent of new technology like electric vehicles. This view is not likely to prove correct in the near-term for two reasons. First, causality tends to run in the opposite direction, as oil prices do more to influence electric vehicle and alternative fuel adoption rates than *vice versa*. The sharp rise in light truck and SUV sales in the U.S. *and Europe* since 2015 highlights the extent to which declines in the price of gasoline stimulate its consumption.[32] Second, at just 0.1% of the global passenger car fleet,[33] electric vehicles are simply not likely to matter quantitatively for the next *several* net investment cycles.

It is not possible to know when supply constraints will again bind. Both history and recent data suggest that productive oil and gas assets embed a convex upside price exposure that is not captured by the futures strip. Like a long-dated, out-of-the-money call option, this convexity is not easily priced, but cannot be ignored. Unlike a call option, however, the more out-of-the money it may look in the short-run, the more valuable it's likely to prove to be in the fullness of time.

31 Carlyle, Bloomberg data, Jan 2017.

32 U.S. Census Bureau, November 2016; European Automobile Manufacturers Association, New Commercial Vehicle Registrations, November 2016.

33 International Energy Agency, *Global EV Outlook* 2016.

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

Chris G. Carter joined NGP in 2004 and serves as Managing Partner of the NGP funds. Mr. Carter chairs the Investment Committee and Monitoring Committee and is a member of NGP's Executive Committee. Mr. Carter oversees NGP's efforts in sourcing, structuring, executing and monitoring investments. He is based in Irving, Texas.

Previously, Mr. Carter was a summer Associate with McKinsey & Company. Mr. Carter was also an Analyst with Deutsche Bank's Energy Investment Banking group, where he focused on financing and merger and acquisition transactions in the oil and gas and oilfield services industries.

Mr. Carter received a B.B.A. and an M.P.A. in Accounting, summa cum laude, in 2002 from The University of Texas at Austin, where he was a member of the Business Honors Program. He received an M.B.A. in 2008 from Stanford University, where he graduated as an Arjay Miller Scholar.

Contact Information

Chris Carter
Managing Partner, NGP
inquiries@ngptrs.com
(972) 432-1440

THE CARLYLE GROUP

GLOBAL ALTERNATIVE ASSET MANAGEMENT

NGP ENERGY CAPITAL MANAGEMENT®