**Addendum to the Baines Creek Capital 2017 Letter to Partners:**
**Oil Markets, A Global Perspective**

This paper is intended as a reference document to supplement the 2017 Annual Letter. Recognizing its length, if you read this addendum in its entirety you will have a very good understanding of both *what we think* about the oil market, as well as *how we think*. As value investors, we attempt to understand the markets that affect the companies in our portfolio (or that we are researching), as well as to understand where we are in the business cycle. Just as a ship's captain checks the weather as he navigates the sea, we seek to understand our investment environment. Since many of our investments over the last couple of years have been oil-related, we felt compelled to share with you our perspective. The primary purposes of this letter is to present to you: 1) how we analyze macro environments that affect our investments and 2) offer some perspective on the oil industry as whole and our current outlook.

The first section, "Historical Context," provides a broad perspective of the development of the global oil market from discovery to the present day. We try to think in terms of *years*, not days or months, recognizing the natural human tendency to let the memory of recent events shine brightest – which makes it difficult to maintain a long-term perspective. The second section, "Oil Industry Operations," provides important information on how the industry operates, from oil extraction to its end-use. Next, the "Oil Markets" section describes the primary fundamental components of the market (production, storage, and demand). Some of you are oil experts. You've made your careers in the industry, and know much more about it than we ever will. For you, although our perspective is sprinkled throughout, you may find the last section, "Current Environment," the most insightful, as it discusses our view of recent events, where we stand in the cycle, and the potential implications for the future.

## <u>Our Outlook</u>

By way of summary, our current view of the oil industry is that in the near to medium term (3-7 years), there is significantly more upward pressures on oil prices than downward pressure. The industry is coming off of a dramatic correction and the world seems to be expecting US shale to meet an ever growing demand. Our view is that demand over the same period is likely being underestimated and US shale and additional production sources will not be sufficient to meet that demand.

We hope this paper proves useful to understanding our outlook.

## CONTENTS


**Historical Context** ........ 2
- Discovery and Early Uses ........ 2
- The Development of the Modern Market ........ 3
  - The Shale Revolution ........ 9
  - Recent Oil Crash ........ 10

**Oil Industry Operations** ........ 12
- Density ........ 12
- Sweet/Sour (Sulfur Content) ........ 13
- Exploration and Production ........ 13
- Refining ........ 17
- Transportation and Storage ........ 18

**Oil Markets** ........ 21
**The Current Environment** ........ 24

## Historical Context

### Discovery and Early Uses

People have collected and used oil for thousands of years. Oil that seeped to the surface was used to waterproof boats, for medicinal purposes, as a construction adhesive, for lighting, and many other creative uses. By 1,000 BC the Chinese had begun to refine crude oil in small quantities. They were also the first to drill for oil (using bamboo poles) around 350 AD.

Although we take it for granted in modern times, artificial light is one of the fundamental tools that man has used to increase his productivity. The freedom from the very limiting constraints of daylight has had multiplicative effects on our ability to transform the world around us. Until the middle of the 19th century, artificial light was primarily produced by burning either beeswax candles or whale oil. Whale oil produced the best light of all available sources and was therefore the preferred product. Overfishing led to a decline in the whale population and resulted in sharply rising whale oil prices, leading to a search for alternatives.

In 1854 George Bissel collected crude oil from the surface of a pond in northwest Pennsylvania and sent it to Yale University to be analyzed in the hopes that it could be distilled into lamp fuel and sold as an alternative to the high-priced whale oil. Yale confirmed that it could, in fact, be distilled into kerosene. There are many by-products of crude oil, all of which have different boiling points. The basic process of refining is to slowly heat the crude, capturing and condensing the various products separately as they evaporate. Kerosene was originally the target product as the other products were either too light (volatile and explosive) or too dense (smoky and dirty) to burn for lamp light. These products were typically dumped. In 1867 the first usable gasoline internal combustion engine was produced. And it was even later (1892) when Rudolph Diesel invented an engine that could burn the heavier by-product (diesel). It was not until the early 1900's that the mass-production of automobiles created the demand for these other products.

In 1855 Bissel formed the Pennsylvania Rock Oil Company and came up with the idea of adapting a salt – mining derrick to drill for oil, hiring Edwin Drake to operate it. There are conflicting accounts of the first commercial oil well; however, it is popularly accepted that Drake's August 27, 1859 oil strike at a depth of 69 feet in Titusville, Pennsylvania was the first significant commercial oil well. The well produced 15 barrels of oil a day.

Others quickly followed Drake and, for a short period, northwest Pennsylvania became the world's largest commercial oil producing region. Until railroad lines were built in the area, oil was stored and transported in the most readily available container – wooden wine and whiskey barrels (barrels were the most common shipping container for commodity goods). In the United States, the "barrel" (bbl) is still the unit of measure for crude oil.

Whale oil's extremely high price caused kerosene to become a convenient (and highly prized) alternative, and the Pennsylvania oil rush ensued. It was during this period that oil earned its nickname "Black Gold." In early 1860 a barrel of oil sold for $18 ($507 in 2017 dollars). The mad rush of drilling and wild over-production in the region caused the price to quickly collapse: by the end of 1861 the price was $0.10 a barrel ($2.64 in 2017 dollars). This was the first oil bust in the United States (and perhaps the world).

Much was learned, at least temporarily, from the Pennsylvania oil rush. Extremely low prices discourage conservation; companies that owned wells were incentivized to produce even more to maximize their revenue so that they could cover their debt payments and remain solvent. Drilling too many wells into a reservoir can cause its pressure to decline rapidly and minimize the total amount of recoverable oil. Modern reservoir management techniques, such as utilizing the pressure of a water reservoir below trapped oil and using dissolved hydrocarbon gases above it to maximize the total amount recovered, were unknown at the time. The depletion of natural resources during the Pennsylvania oil rush (and environmentally destructive behavior by producers) caused an outcry for regulation of the burgeoning industry – and regulation has been a significant component of the oil industry ever since.

As he did with other industries, during the late 1800's John D Rockefeller consolidated and monopolized the industry into the Standard Oil Company until he controlled 90% of the US market. Standard Oil standardized the unit of measure to be 42 gallons (multiple barrel sizes were available for shipping goods at the time). Buyers expected that a 42 gallon barrel would contain at least 40 gallons upon delivery because oil expands and contracts as its temperature changes (and to account for evaporation and leaks from the wooden barrels). Today, variations of several percentage points (by volume) are still often accepted in order to account for volumetric expansion and contraction. Outside of the US, transactions are usually conducted in metric tons (mass not volume) in order to more accurately reflect the quantity being transacted.

After Pennsylvania, small amounts of oil were also discovered in Texas, Oklahoma, and California, but few US wells produced more than 50 bbls per day (bpd). Oil extraction (today called "production") was enough to supply the lamp oil industry, but little else. For this reason, Henry Ford's first engine-powered four-wheel vehicle (the quadracycle) ran strictly on ethanol in 1896. Discovered in 1901 in Southeast Texas, Spindletop was the first American oil well gusher, producing over 50,000 bpd. It was such a massive find that it produced roughly 20% of the entire US daily crude oil production. As the supply of petroleum increased, the market embraced it. When the Model T was released in 1908 it could run on either ethanol or gasoline. Eventually, Ford stopped producing vehicles that could run on either fuel and focused on gasoline engines.

In 1908, the British state-controlled Anglo-Persian Oil Company (known today as BP) discovered large quantities of oil in the Middle East. These and other large discoveries supplied the cheap and readily available fuel that was needed to meet the growing automobile demand for gasoline, which had replaced kerosene as the dominant refined oil product. Petroleum products gained further demand during WWI when the British Navy replaced their coal-powered ships with faster, more dynamic oil-powered vessels that burned the heavier (and cheaper) residual fuel oil that is a byproduct of gasoline production. Today this fuel is still called "bunker" fuel, a remnant of the era when ships contained large coal bunkers.

The electrification of households in Europe and North America began in the early 20th century (beginning in major cities) and increased rapidly. By 1930 nearly 70% of US households were electrified and using incandescent lighting. This significantly reduced the demand for lamp oil (kerosene). Concurrently, Frank Whittle invented the jet engine in the 1930s - which could be configured to operate on a wide range of fuels. However, during WWII both gasoline and diesel were in strong demand for wartime operations. Therefore, due to its availability, kerosene was adopted as the fuel for jet engines and remains the predominant fuel for all modern aircraft.

By the end of WWII crude oil had completely transitioned from a source of lamp oil to a transportation fuel. Today, transportation remains the primary source of demand for crude and accounts for roughly two-thirds of consumption (comprised of gasoline, diesel, bunker fuel, and kerosene/jet fuel). The remaining third of oil consumption is made up of plastics, petrochemicals, asphalt, and heating oil.

**The Development of the Modern Market**

The growing demand for petroleum products in the first half of the 20th century spurred investment in crude oil production. Entrepreneurs and inventors became so good at finding oil (sometimes in massive quantities) that the supply regularly outstripped the demand and long periods of low prices resulted. Low prices encouraged consumption and demand would gradually catch up.

This brings us to one of our first fundamentals in this industry. The region(s) (or producer) with excess production capacity will have an ability to control at least local, if not global, crude oil prices by controlling at will the supply of oil in to a given market.

In 1930 crude was just over $1 per barrel (over $14 in 2017 dollars) and by 1931 had crashed to $0.10 per bbl ($1.50 in 2017 dollars). Trying to jump-start the economy in the midst of the Great Depression and encourage industrial investment and growth (including the oil industry), the US government required state organizations to impose production restrictions to control the amount of oil produced in each state. This stabilized prices at "profitable" levels, but in effect, killed the "free market". The Texas Railroad Commission (RRC) regulated all of Texas' production. Since Texas was the largest oil producing state at the time and East Texas had spare production capacity, the Texas RRC was able to control global oil prices from 1931 to 1971.

During this period, much of the global crude production outside of the US was conducted through the use of "concessions." In most (but not all) countries outside of the US, the government owns the minerals, not the land-owner. A "concession" is a contract between a government and an International Oil Company (IOC) to extract crude oil. As an example, Saudi Arabian oil was discovered in 1938 and extracted by a number of western oil companies (led by Chevron) on a concession basis. Concession pricing typically resulted in a 50/50 revenue split between the company and the government, based on a "posted price" set by the company – which allowed the company to link the price of the oil they produced to the transparent market on the US gulf coast (by subtracting shipping costs from the posted gulf coast price – even if the crude was never intended to be shipped to the US). At the time there was no free-floating global oil price and it remained fixed for months or even years at a time.

Since Texas had spare capacity (generally defined as the ability to bring additional production on-line within 30 days and sustain it for at least 90 days) and the Texas RRC controlled Texas production, it effectively controlled total US production and the US gulf coast posted prices (against which nearly all global oil was priced). As a result, the TX RRC also controlled global crude prices. However, this price was not connected to the global price of refined products. The governments subject to concession pricing often felt that their oil was being sold at too low a price relative to the price of refined products. They felt that too much money was being made by the refiners (many of which, incidentally, were owned by the IOCs). Governments of oil-producing nations began to push back against concession contracts.

In 1951 the democratically elected prime minister of Iran, Mohammed Mossadegh, nationalized Iran's oil industry by taking possession of the British owned and operated Anglo-Iranian Oil Company. This became known as the Abadan Crisis. The British government retaliated by imposing a trade embargo on Iran to prevent other countries from purchasing Iranian oil and refined products. The crisis culminated in the British Special Forces and US CIA intervening and reinstalling the previously removed Shah of Iran in 1953. The Shah immediately reinstated concession pricing with British, American, and French oil companies at the original 50/50 concession price.

In 1960 the Organization of Petroleum Exporting Countries (OPEC) was formed in Baghdad with 5 founding members: Saudi Arabia, Kuwait, Iran, Iraq, and Venezuela. However, OPEC had little power because international oil companies controlled (through concessions) all production in OPEC nations. In addition (and perhaps more importantly), the Texas RRC still controlled global prices by adding or subtracting oil supply to manage global oil prices. In 1970, Libya's Muammar al-Gaddafi obtained a concession of 55% from Occidental Petroleum. Every other producing nation quickly sought an increased concession. At the same time, US production had peaked and began to slowly decline. Demand, however, was steadily increasing. By 1971 Texas' excess ("spare") production capacity was gone, and the Texas RRC gave producers the freedom to produce as much oil as they wanted. The era of the TX RRC controlling global oil prices was over. OPEC, suddenly finding itself in control, quickly began to unwind concession contract pricing. But it took time for a new global pricing mechanism to develop.

> NOTE: From the mid-70s to the late 2000s US oil production declined by nearly 50% and the US became the world's largest importer of crude oil. US oil imports rose from 1.3 million bpd to more than 10 million bpd. Legally, the old rules giving the Texas RRC the ability to control Texas production still existed in law, but were effectively useless as there was no spare capacity.

In 1973 Egypt and Syria conducted a surprise invasion of Israeli-held territory (the Yom Kippur War). Egypt's military was supported with equipment and supplies from the Soviet Union. In support of their ally (and in opposition to the Soviet Union), the US sent supplies and military equipment to Israel. The Arab nations saw the US military support of Israel as an aggressively anti-Arab provocation. In retaliation, the Arab OPEC members cut off supply of crude oil to the US. This became known as the "Arab oil embargo" and instantly cut the world oil supply by 5-10% (it was not an "official" OPEC embargo – the Shah of Iran, among others, did not cut supply). The embargo lasted 6 months and had several important consequences: the price of oil multiplied fourfold, OPEC members gained an instructive lesson on their new-found power over the oil market, and it quickened the pace of nationalizing oil production in producing counties (called National Oil Companies, or NOCs). To this day, the Arab oil embargo remains the only time that oil-producing nations have used oil as an economic weapon, but it continues to impact behaviors of countries on both sides of the embargo.

> NOTE: There was no global shortage of oil in the 1970s. Government action and price controls resulted in artificial, localized shortages. At the time of this writing, we are witnessing something similar in the Natural Gas market in the Northeast US: we have an abundance of natural gas, but pipeline bottlenecks are preventing the abundant supply from reaching the Northeastern areas currently being slammed with Arctic temperatures. The result is local extreme price spikes despite abundant resources. Bottlenecks in any system (whether physical or artificially created by government action) can result in localized shortages and localized price spikes despite global abundance.

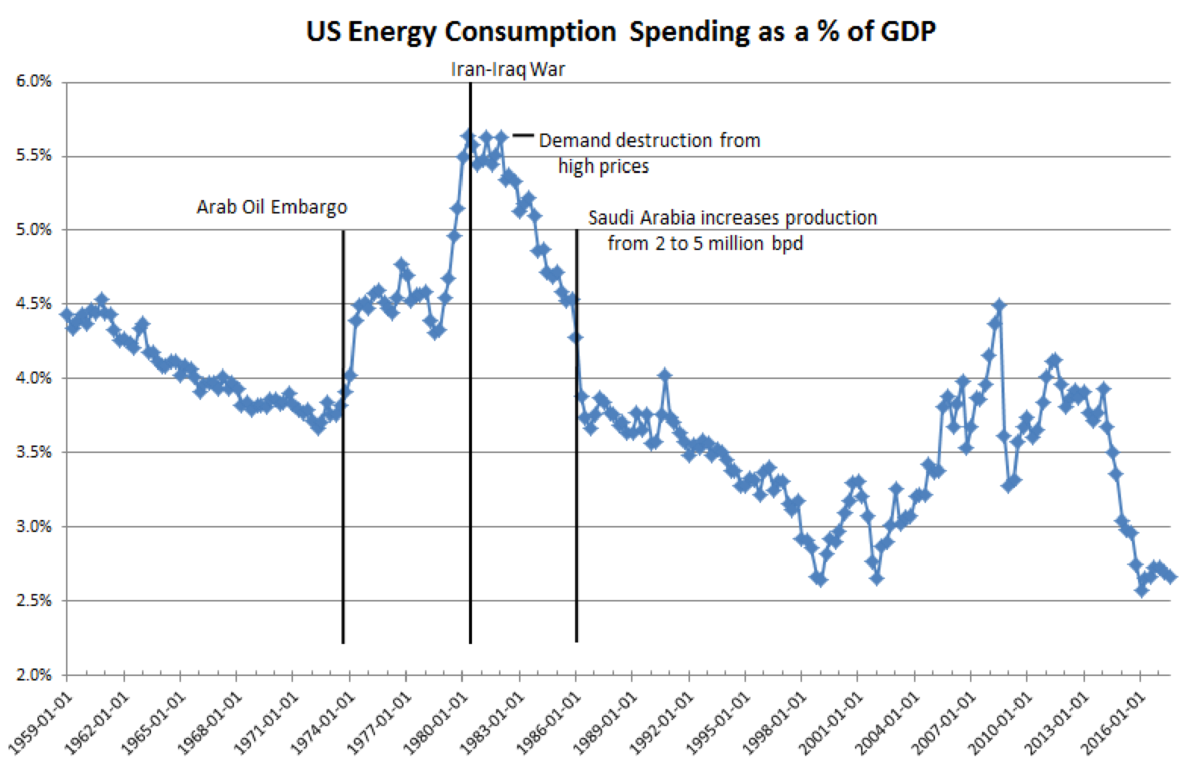
As a response to the oil crisis, the Organization for Economic Cooperation and Development (OECD) formed the International Energy Agency (IEA) in 1974. Based in Paris, France, the IEA collects global inventory data and publishes it in a monthly oil market report (along with forecasts), which remains one of the most widely-followed reports by market participants. One of the IEA's first actions was to recommend that consumer countries create stockpiles of crude oil (refined products degrade relatively quickly and are more difficult to store for long periods) to act as buffer in times of crisis. In response, the US banned the export of US crude and created the Strategic Petroleum Reserve (SPR) in 1975 to be used for emergency purposes. The US remains the largest holder of a SPR (although the volume of oil in China's SPR is subject to much speculation and uncertainty).

In 1977 the US Department of Energy (DOE) created the Energy Information Administration (EIA) to provide the statistical functions necessary for the DOE to provide policy advice to the executive branch of the government. The EIA provides both weekly and monthly figures for US production and storage of crude oil and petroleum products. The figures are compiled from industry surveys, company reporting, and state agency reports. In a world where national security (and companies' competitive advantages) is most often safeguarded by secrecy, the EIA reports are some of the most transparent in the world. In addition, they are published with frequency (both weekly and monthly). This creates the appearance of reliability and satisfies the market's hunger for data.

During 1978 and 1979 the Iranian people, led by Ayatollah Khomeini (a fundamentalist Muslim cleric), revolted and overthrew the Shah. The internal conflict dramatically reduced the country's oil production, which was initially compensated for by increased production from Saudi Arabia (who temporarily brought production up to 10 million barrels per day). Then, in 1980, the Iran-Iraq War resulted in further supply reductions from both countries. Prices spiked to over $38 per barrel (over $119 in 2017 dollars). During this price spike, the cost of oil consumption (as a % of GDP) rose to the point that consumers were compelled to become more efficient with their use of oil. It is important to note that the absolute price is not as important as the price relative to the consumer's other expenses. For the very first time, the oil market experienced demand destruction due to high prices (see chart below).

Demand destruction primarily took the form of advances in engine technology and lower horsepower engines. Many US cities developed alongside the automobile. As a result, most large US cities were built *for* the automobile. For most Americans, getting around without a vehicle is extremely difficult – so people began to drive lighter, less powerful vehicles and to change their driving habits.

During the early 80s, Iran's internal conflicts abated and they began to bring production back on-line. To keep prices from completely collapsing, Saudi Arabia brought their production back down to about 2 million bpd. However, many OPEC countries had spare capacity at the time and they took advantage of the Saudi reduction by cheating on their quotas (Iran and Iraq were especially lax with their quotas as they were funding their war effort with oil revenue). Then, in 1985 Saudi Arabia increased their production from 2 to 5 million bpd and simultaneously stopped selling their crude at an officially posted price. Instead, they linked the price of their crude to the market prices of finished products (gasoline, diesel, etc.). This excess supply crashed the market: by 1986 the price per barrel of crude dropped to $15 ($33 in 2017 dollars) and remained in the $10-$20 dollar range until 1990. This crash in prices nearly bankrupted the entire US oil industry as well as the Soviet Union's economy (at the time, Russia was the #2 oil producer after Saudi Arabia) – however, it was a boon to the US consumer who saw their energy consumption expenses meaningfully reduced.



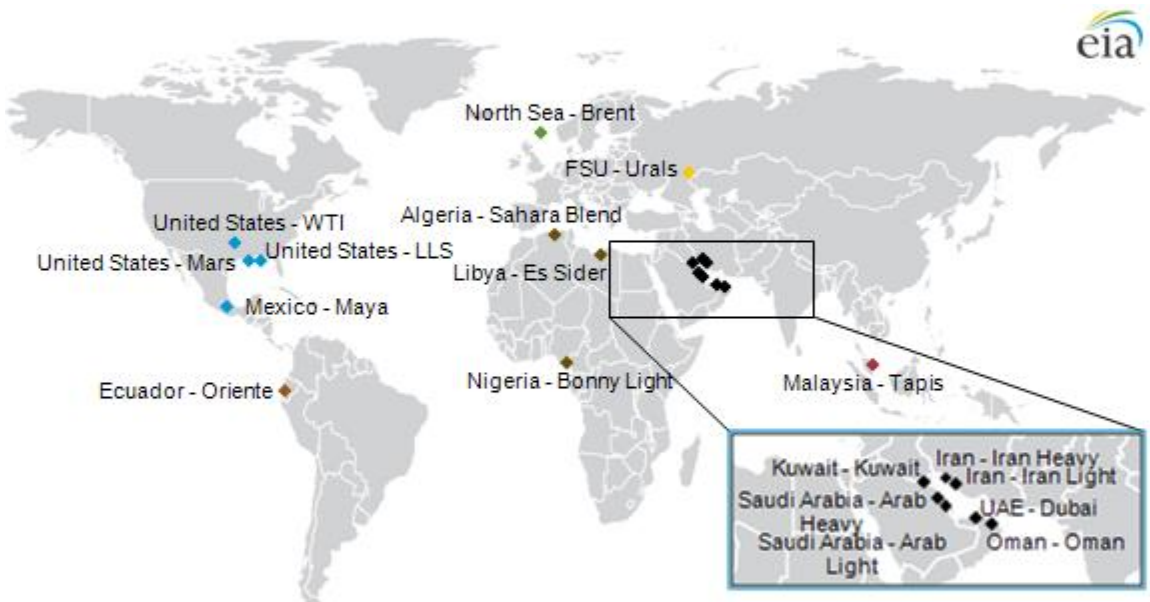

Source: U.S. Bureau of Economic Analysis, Baines Creek Capital

Oil prices were cut in half, but Saudi production more than doubled – so overall it was a net gain to the Saudis. Saudi Arabia had a dual problem: 1) large social entitlement programs compounded by; 2) a quickly growing population. The Saudis were acting in an economically rational way (at least for the short term).

> NOTE: This can be a rational decision for NOCs. Most oil producing countries have power concentrated at the top of some form of authoritarian government. The populous is kept placated by either brute force or social entitlement programs. When prices crash, the NOC is incentivized to *increase* production in order to keep the government's revenue up (the revenue has decreased, but the expenses have not: you still have to pay either the brute enforcers or placating social entitlements if you want to remain in power). Decreasing production is the rational *long-term* solution, as it will eventually raise prices – but that does not necessarily keep the decision-makers in power during the short-term.

The move to link the sales price of crude to product prices ended the era of "posted" prices and began a new era of real-time pricing. Global refining capacity (which was largely located in western countries) had significantly increased due to the somewhat "guaranteed" margin between the posted OPEC price and market price of refined products. The pricing mechanism quickly changed into today's system: where there are a number of openly traded free market benchmarks and producers sell crude oil in relation to these benchmarks. For example, Saudi Arab Light crude is sold at the Intercontinental Exchange (ICE) Brent benchmark price plus or minus a differential (set by Saudi Aramco, the NOC of Saudi Arabia).

**World Benchmarks**



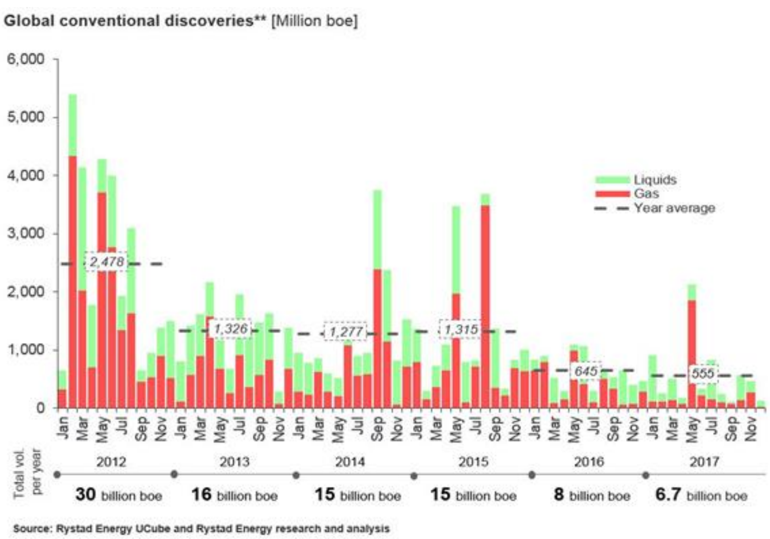

Source: EIA (https://www.eia.gov/todayinenergy/detail.php?id=7110)

In 1990 the world experienced another price spike. This was caused by Iraq's invasion of Kuwait and the subsequent Gulf War led by the US and other western nations. However, the war was very short and the US used its SPR to effectively prevent the price spike from being either permanent or economically damaging. During the remainder of the 1990's and early 2000's the price was relatively stable. OPEC managed its spare capacity with reasonable success. For example, the 1997 Asian financial crisis significantly curtailed demand. As a result, OPEC (plus Norway and Mexico) cut production in order to improve prices.

During this period consumer preferences and habits changed again in response. The energy efficiency gains previously attained began to be eroded by the popularity of SUVs and larger, more powerful vehicles. The technology existed to produce more efficient vehicles (and the technology gains were not completely abandoned), but the consumer's preference for larger, more powerful vehicles began to off-set the efficiency gains. Just as high prices had previously destroyed demand, low prices began to stimulate it. It is important to note that the absolute price is not as important as the price in proportion to the consumer's other expenses. So long as the consumer can afford to purchase and operate the large SUV, they seem to want it (at least in the US – and early indications are that, in this respect, the growing Chinese middle-class consumer is not much different).

By 2005 OPEC had attempted to manage excess capacity for roughly 35 years (since the Texas RRC had lost its de facto power back in 1971). During this time they (and specifically Saudi Arabia) had become known as the "swing producer" for their ability (and willingness) to quickly bring additional production on or off-line as needed. However, by 2005 they had let the price of oil rise significantly to $68 (or $86 in 2017 dollars). As demand continued to rise in subsequent years, OPEC did not bring on-line additional supply to meet it. Consequently, prices continued to rise. We cannot know why (and many speculators pontificate about it) but we can surmise that they did not bring production on-line for one of two reasons: 1) they did not want to because they enjoyed the additional revenue from higher prices (and unless they were thinking extremely short-term they must have also thought that no one else in the world would be able to increase production), or 2) they no longer had any spare capacity to bring on-line (either from outright scarcity or from lack of adequate investment). In either case, it is ironic that this is eerily similar to the Texas RRC's decision back in the 70's to allow US producers to produce at maximum levels (since they no longer had any spare capacity) – which had given OPEC its power.

What is known, with certainty, is that actual reserve and spare capacity estimates in oil producing nations are closely-held state secrets. The governments have no incentive to let others know what they do or do not have. We also know that soon after the turn of the century many OPEC nations (including Saudi Arabia) began investing in off-shore production (which is more expensive than land-based production). Many, for this and other reasons, surmised that there was a lack of global spare capacity. During this period the theory of "Peak Oil" gained a lot of traction (the theory posits that the world's stores of oil have peaked and will decline, resulting in the effective reversal of the industrial revolution). In addition, consumer behavior changed once again. "Hybrid" vehicles such as the Toyota Prius gained a lot of popular attention. Demand destruction had begun again. Oil analyst Charles Maxwell (of Weeden & Company) said,




"In 1930, we found 10 billion new barrels of oil in the world, and we used 1.5 billion. We reached a peak in 1964, when we found 48 billion barrels and used approximately 12 billion. In 1988, we found 23 billion barrels and used 23 billion barrels. That was the crossover when we started finding less than we were using. In 2007 we found perhaps 6-7 billion, and we used 31 billion. These numbers are just overwhelming."

## The Shale Revolution

High prices not only began to crimp demand, they also spurred free market innovation and human ingenuity. Few cultures have embraced the virtues of rugged individualism and entrepreneurial innovation like Americans have. It is, therefore, not surprising that the next big shift in the oil markets took place in the United States. It was long known that shale formations held oil, but it was believed to be inaccessible due to the low permeability of the reservoir rock (they are sometimes called "tight" formations because of how tightly they hold on to the imbedded oil). High prices provided the financial incentive to discover new methods to extract this oil. Modern oil companies have always had to carefully control the pressures of the drilling fluids they used so as not to fracture the formations they were drilling through (potentially damaging the well and/or the formation). Too much pressure and they may damage the reservoir, too little and the wellbore may collapse (or the cuttings not circulate up and out of the well). It was American entrepreneurs who first used this knowledge to intentionally fracture oil-bearing formations in order to stimulate the formation's release of hydrocarbons. Developing this technology was expensive, and high prices were a necessary prerequisite.

By 2008 the price had climbed to nearly $140 dollars ($157 in 2017 dollars) and despite demand destruction (such as switching to Hybrid vehicles and changing driving habits), global GDP growth was overpowering demand destruction and causing demand to continue to grow. This came to a head in 2008 during the global financial crisis (some economists even blame the pricking of the US housing bubble on high oil prices). The global financial crisis (followed by the "Great Recession" in the US) destroyed demand. OPEC (led by the Saudis) responded by curtailing supply in order to support prices. This cut, at least in the short-term, ensured that OPEC (or at least Saudi Arabia) once again had spare capacity available. By 2009 prices had recovered and resumed their upward march (though not back to their 2008 peak) and OPEC was once-again producing at pre-financial-crisis levels; bringing into question, once again, the availability of OPEC's spare capacity.

As a result of the financial crisis, the US Federal Reserve kept interest rates extremely low to encourage economic growth. High prices combined with extremely low interest rates were the fuel that was needed for shale production to be aggressively exploited. Cheap debt provided the capital necessary for ingenious American wildcatters to figure out how to exploit this new-found resource. The "shale revolution" had arrived, and America was pursuing a path to "energy independence." With the usual American exuberance, the US oil industry began to perfect the techniques of extracting this newly available resource. OPEC, for the time-being (and for reasons known only to them), did not immediately respond (further fueling the "Peak Oil" debate).

Shale production combines very long horizontal wellbores with highly pressurized water and chemicals to fracture the reservoir rock and fill the resulting cracks with sand (known as "proppant") to keep the fissures open and allow hydrocarbons to be released. By 2014, US businesses had nearly perfected this newfound production technique. The United States' oil production had reversed: from steady decline to growth.

However, due to the US export ban instituted decades earlier, this newfound source of crude could not leave the United States. In addition, not all oil is the same. The oil produced from US shale formations is much lighter (less dense) than the oil that was traditionally produced in the US. Furthermore, US refineries (which are some of the most complex and advanced in the world) are optimized to refine heavier, denser forms of crude (most of which it had been importing from OPEC nations). Fueled by high prices, cheap debt, and ingenuity, the world, once again, was producing more crude than it needed. Much of this excess was in the extremely light grades and was accumulating in the US (government regulation and physical constraints (refineries' configuration) had created a localized surplus).

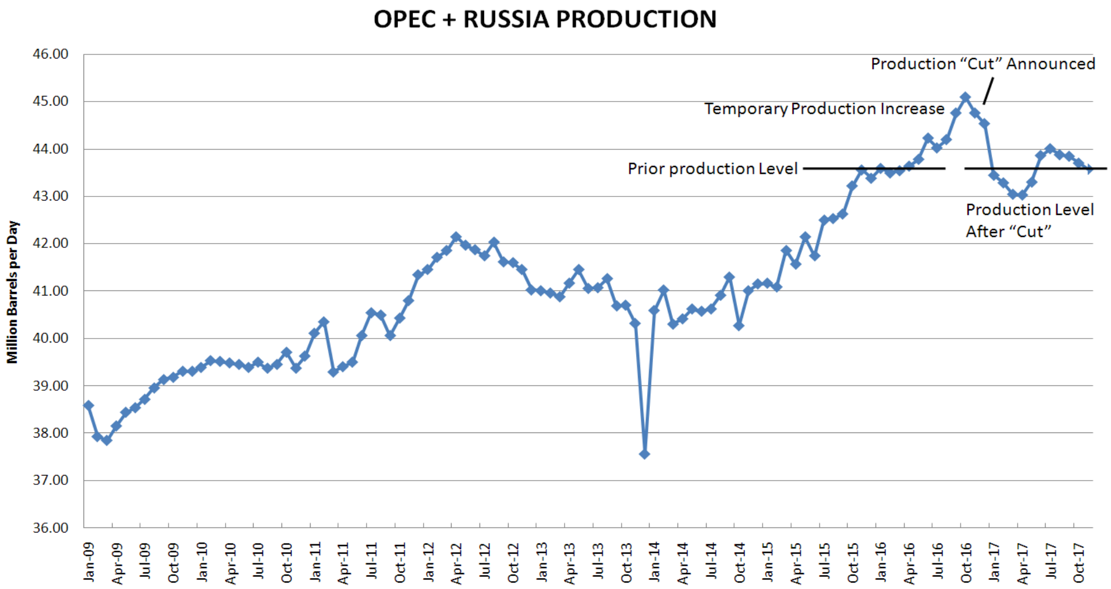
> NOTE: High prices and low borrowing costs also increased investment in other expensive forms of crude production such as deep water off-shore and tar-sand mining. These large investment

projects take multiple years from investment decision to first production (and typically result in large amounts of production when they do come on-line). All forms of high-cost production were being creatively exploited by the industry.

Recent Oil Crash

In 2014, not only was US production booming, but economists were predicting a slowdown in emerging market growth. Then, OPEC member Libya (who had been engaged in a protracted civil war) began to stabilize, re-opening closed export terminals, and shipping significantly more crude than it had in the recent past (or than anyone was expecting). Whatever the specific causes were (there were likely many more), what was important was the shift in market perception: from under-supply to over-supply. The market's realization of over-supply quickly resulted in a significant drop in prices. Theorists switched from "Peak Oil" to "Peak Demand:" CNBC routinely had pundits claiming, "There is so much oil that we will never use it all, we're drowning in it!" Many market participants believed that OPEC would, as in the past, step in and reduce supply in order to stabilize prices. However, OPEC appeared to not want to subsidize more expensive production. In November 2014 OPEC, led by Saudi Arabia, notified the market that they would maintain their combined output – they would not cut supply to support the market. Prices quickly fell further. Then, in a 2015 international nuclear weapons agreement, the Obama administration lifted sanctions on Iran. This allowed Iran to bring additional oil to market for the first time in many years, which placed further pressure on prices. The US also lifted its export ban on crude, but it would take time for market mechanics and infrastructure to develop to allow it to meaningfully change trade routes.

During 2016 prices continued to fall; reaching $26 in January and then again in February before stabilizing in the $40s. (The panic in the markets and the media during this time was palpable. Pundits were predicting that oil would never trade above $60 again. We would fill "every swimming pool in Texas" with crude. Prices would be "lower for longer" and then "lower for even longer.") The sustained drop in oil prices curtailed investment in exploration and production worldwide. By the end of the year, believing that they had sufficiently crimped excess high-cost production, OPEC (plus Russia) agreed to support prices by "cutting" production. However, once OPEC began discussing cutting production, all member nations that could began increasing production to the greatest extent possible (potentially even selling stored inventory) in order to maximize their production numbers (from which the cuts would be calculated off of). Once the "cut" went into effect, OPEC and Russia (as a group) were still producing the same amount as they had been before they increased production (see chart below). The market has given OPEC credit for *cutting* production, when in fact, what they actually did was to *freeze* it (at a historically high level). In late 2017, OPEC and Russia agreed to extend the "cut" through the end of 2018.




Source: OPEC, EIA, Baines Creek Capital

Prices have gradually recovered since the 2016 lows. Two years of low prices has effectively curtailed investment in high-cost production sources (US shale is the only one that has shown any potential to grow production – and there is a high degree of uncertainty around their additional production ability at current prices). The steady depletion of producing reservoirs during this time has somewhat off-set increases in production from shale producers and high-cost investments (made years prior) finally coming on-line. In addition, the consumer's habits have changed once again. Low prices no longer rewarded efficiency gains and the preference for larger, less fuel-efficient vehicles has quickly returned.

This brings us to present day. OPEC is still attempting to actively manage the market, while not subsidizing high-cost production. Demand is continuing to grow, and worldwide stores are declining; which indicates that demand is greater than supply. Investment in new production is at historic lows which will have significant impact on future supply. And, as a result, prices are continuing to rise. These topics are discussed in further detail below.

## Oil Industry Operations

An oil reservoir is not an underground "lake" of oil. It is held in the fine pore spaces within sold rock (like a solid rock sponge). Crude oil is believed to be formed by sedimentation of marine material when ancient rivers or oceans deposited organic material to the bottom in sedimentary layers over many years. Over geologic time, these sedimentary layers eventually became solid rock and the organic material became hydrocarbons imbedded in the rock. The source rock texture and grain size can be extremely porous or extremely fine. "Porosity" is measured by the percentage of voids within the rock (relative to solid rock). "Permeability" defines how well these pores are connected to each other. Sandstone is very permeable, while shale is extremely impermeable. "Viscosity" measures how easily oil flows at reservoir depth and temperature. The porosity and permeability of the reservoir rock, and the viscosity of the oil in place, all affect what type of crude is able to make its way to the surface of the well.

The type of organic material deposited, as well as the conditions under which the source rock was formed (in addition to the way hydrocarbons may have travelled through bedrock over long geologic time periods) all determine the type of oil that is in place in any given reservoir. Crude oil is not always black; it can be brown or even tan. At room temperature it can be nearly solid or as viscous as water. It may contain sulfur, nitrogen, metals, water, and sediment. There are hundreds of varieties of crude produced today.

Crude oil has virtually no uses in its natural form: it must be processed in a refinery into individual finished products. Different varieties of crude produce different quantities of refined products, depending on the composition of the crude. Production from individual wells is combined for pipeline transportation to create a "stream" of crude. Multiple streams are often combined to produce a "blend" of crude. Most transactions are made for a specific blend of crude, which is usually named after one of its dominant component streams. For example, "Brent Blend" is named after the Brent stream in the North Sea (although the blend also contains streams of similar quality crude from other streams).

### Density

Generally, the most important physical characteristic of a variety of crude is its density, which provides an indication of the type of hydrocarbon it contains, and thus the types (and quantities) of refined products that it will yield. Lighter (less dense) crudes are simpler to refine and yield a greater proportion of lighter products (such as gasoline), and therefore tend to be more valuable than heavier crudes.

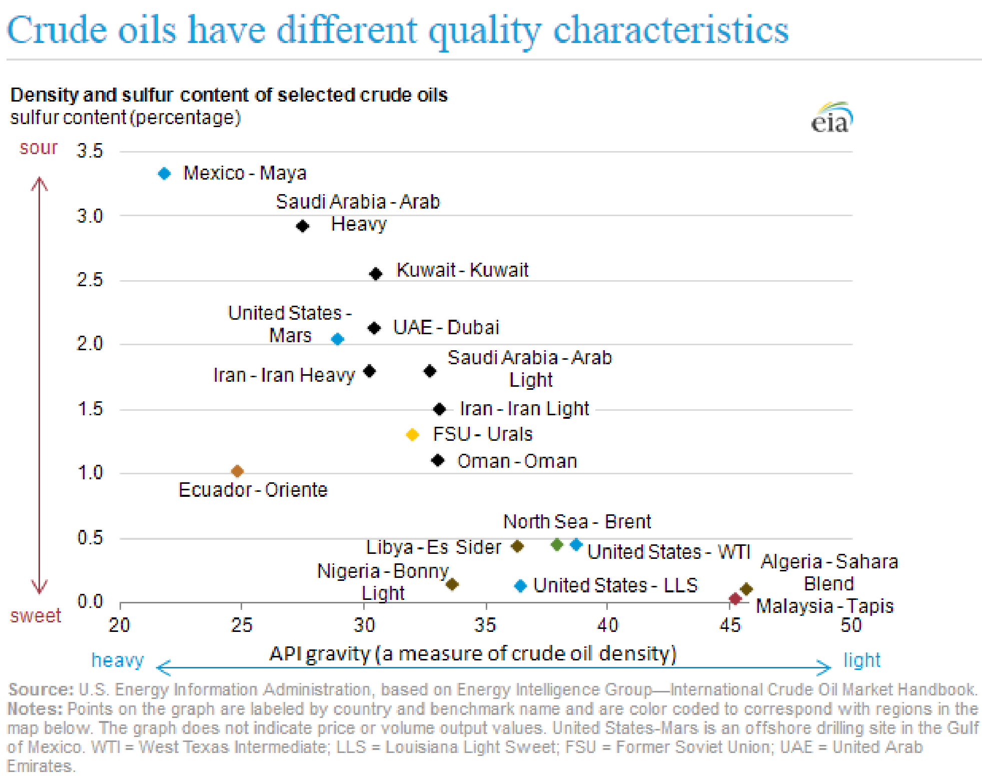
Specific gravity is the most commonly used measurement of crude oil density. In 1921 the American Petroleum Institute created an index of specific gravities to standardize the measurement of oil density. As a result, "API" is still the most commonly used measurement in use today. For context: water has an API of 10, bitumen (the primary component of road asphalt) has an API of about 7 (and will sink in water), and gasoline has an API of 50 (and will float on water). West Texas Intermediate crude (WTI), the most common US benchmark, has an API of about 40.

| Crude Oil Density Classification | API Gravity |
|---|---|
| Condensate/Extra-Light | >50 |
| Light | 40-50 |
| Intermediate/Medium | 30-39 |
| Medium-Heavy | 25-29 |
| Heavy | <25 |
| Extra-Heavy | <10 |

**Sweet/Sour (Sulfur Content)**

Sulfur molecules displace hydrocarbon molecules in a given unit of oil, reducing its energy content. Consequently, sulfur reduces the value of a crude blend. In addition, sulfur is corrosive to oilfield and transportation equipment and is a pollutant, raising the cost of handling the crude (and reducing its value further). "Sour" oil is high in sulfur content, while "sweet" oil is low in sulfur content. Environmental regulations in most nations require that refineries remove sulfur from finished products (accomplished using "hydrotreater" units). Refineries that do not have these units are unable to refine sour blends. The graph below shows the density and sulfur content of the world's major benchmarks.

| Sulfur Content | % By Weight |
|---|---|
| Sweet | < 0.5 |
| Medium Sour | 0.5-1.5 |
| Sour | > 1.5 |




**Exploration and Production**

The exploration and production segment of the industry is referred to as "upstream." It involves the location and extraction of hydrocarbons (also called "reserves) from below the earth's surface. Both geologists and geophysicists work to discover oil deposists deep below the surface. Geologists study the physical structure of the earth's surface and subsurface. Geophysics is the study of the interaction of matter and energy. For example, seismic surveys measure how sound waves reflect off of various subsurface layers (similar to a doctor conducting a sonogram), giving an indication of if hydrocarbons are present and how much.

There are no global standards for oil reserve definitions. However, here are some commonly used terms:

| **Acronym** | **Definition** | **Term** |
|---|---|---|
| Original Oil In Place (OOIP) | Total oil in the ground (both known and unknown) | Total Oil |
| Ultimate Recoverable Resource (URR) | Oil which is able to be extracted (a fraction of OOIP) | Resources |
| Estimated Ultimate Recovery (EUR) | An estimate of URR | Historical Production + **Reserves*** |

| ***Reserve Components** | **(according to US GAAP)** | **Terminology** | | |
|---|---|---|---|---|
| P1 (Proven) | 90+% probability of recovery, counted as an asset on balance sheet | 1P | 2P | |
| P2 (Probable) | 50-89% probability, <u>not</u> an asset | | | 3P |
| P3 (Possible) | 10-49% probability, <u>not</u> an asset | | | |

Once oil is expected to be found in a specific location (and the right to extract it is obtained) the hydrocarbons are accessed by drilling a wellbore to the reservoir. Drilling techniques have evolved in tremendous ways over time. A series of hollow drill pipe (called the drill "string") connects the drill rig to the drill bit at the bottom of the hole. Fluids (or "mud") comprised of water, clay, weighting material, chemicals, and other additives are pumped at pressure through the drill string to the drill bit: both cooling it and circulating cuttings to the surface (which are analyzed at the surface by a geologist known as a "mud logger"). In addition, the pressurized fluid prevents the wellbore from collapsing on itself. Too much pressure and it could damage the formation, too little and it won't be effective. The mud is often specifically designed for the characteristics of the given formation.

Most well bores are lined with steel casing and then cement is circulated through the well to fill the space between the casing and the wall of the drilled well. Casing may occur periodically or throughout the entire well bore. The casing prevents contamination of groundwater from oil production, prevents water intrusion into the well, and improves the structural integrity of the well. New casing must be passed through any previously set casing. As a result, casing pipe gets narrower as the well gets deeper. A well may have a 20 inch diameter at the surface and step down to 6 inch diameter in the reservoir source rock.

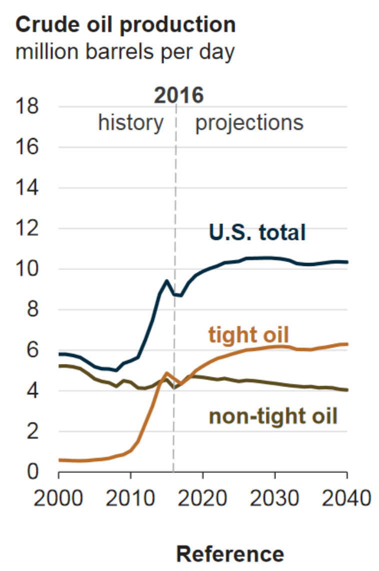
"Well completion" is the terminology for installing the final equipment used to actually extract the crude. The drilling rig is removed and a "work-over" or "well-servicing" rig is used. Typically, production flowline tubing is installed (smaller diameter tubing through which the crude oil will flow to the surface). In the case of hydraulic fracturing, the casing is perferorated in sections using charges installed in a perforating "gun" which create many narrow channels in the casing. Special mud is then injected into the well at high pressure, which enters the formation through these perforarations and fractures it, simulatneously inserting sand granules into the fractures in order to prop them open. This increases the permeability of the oil-bearing rock and allows oil to move to the well-bore. Due to the low porosity and low-permeability of the source rock, only the lightest parts of the oil are able to move to the well-bore. Crude produced from fractured wells usually has an API above 40.

Pressure and temperature increase in direct relation to the depth of the well. This pressure, at depth, relative to the atmospheric pressure at the earth's surface is called the pressure "differential." This pressure differential forces oil to move through the reservoir rock and up the well shaft (called "Primary Recovery"). Pumps are sometimes installed to assist in lifting the oil to the surface. Reservoir pressure is reduced every time that oil is extracted – until no more oil will move through the source rock. It is rare to be able to extract more than 60% of the original oil in place (OOIP) – even when using all known recovery methods. Each reservoir has an optimal recovery rate that will maximize the amount of oil produced before reservoir pressure is depleted. If one extracts oil above this rate, the ultimate oil recovery will be less than would otherwise have been possible.

"Secondary recovery" is a method to increase reservoir pressure once the initial pressure differential has been depleted. Also called "water flooding," this method involves injecting water into the reservoir. In addition to increasing reservoir pressure, the water moves through the reservoir away from the injection well, and pushes oil toward the production wells. This obviously adds additional cost to the oil production operation.

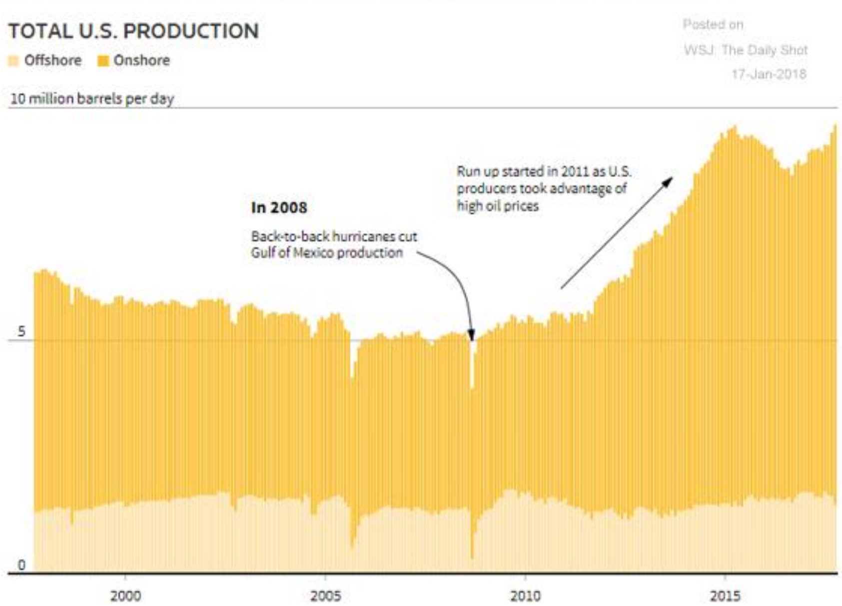
"Tertiary recovery" (sometimes called "enhanced oil recovery") is an additional means of pressurizing the reservoir once primary and secondary methods are depleted. It most often involves injecting a gas (typically CO2) into the reservoir. Besides increasing the pressure, the injected gas chemically reacts with the oil in place and allows it to more freely move through the reservoir. Again, tertiary recovery is also more expensive than secondary recovery.

The terms "conventional" and "unconventional" oil production are somewhat loose. The above-mentioned recovery techniques applied to land and shallow-water locations are generally considered to be "conventional" production. In general terms, conventional oil production has peaked (or, at a minimum, its *growth* has peaked). In this millennium, so far, the majority of growth in oil production has come from unconventional sources (off-shore, tar sand mining, and tight shale fracturing). Drilling an oil well in thousands of feet of water and/or in severe conditions (such as near the Arctic Circle) obviously adds a tremendous amount of complexity and expense to the endeavor. Deepwater production, is therefore one of the highest-cost production methods. "Unconventional" production typically refers to drilling (and fracturing) horizontal wells into extremely low-permeability reservoirs. Below are graphs showing US production by source ("tight oil" is a reference to fractured shale production):




U.S. Energy Information Administration

U.S. shale oil production took off this decade, as drilling soared on crude price increases.

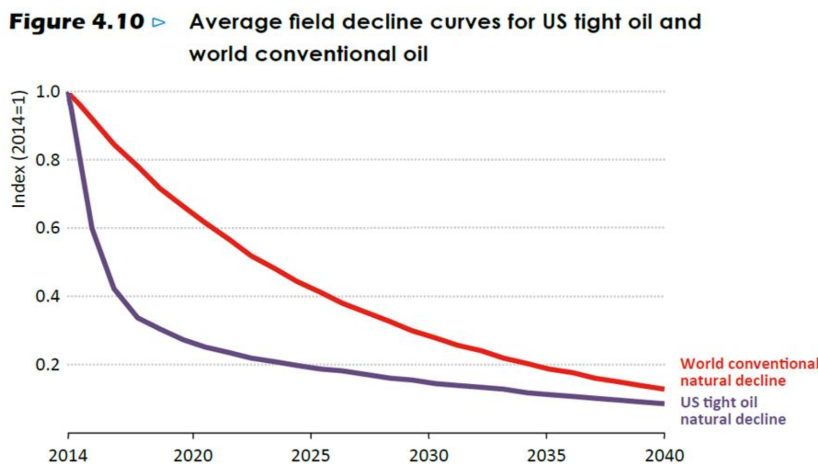



Source: U.S. Energy Information Administration
By Han Huang | REUTERS GRAPHICS

Deepwater off-shore production requires the installation of significant infrastructure, not only to drill and extract the oil, but also to handle and transport it once it is brought up. Consequently, developing a new field typically takes many years and enormous amounts of capital. An exploratory well is usually drilled first, to prove the existence of the reserves. Then, off-shore infrastructure must be installed to handle the production. Finally, additional wells are constructed and connected to the collection infrastructure. These additional wells are called "tie-back" wells. Off-shore wells usually produce large quantities of oil per well under extreme pressures (the weight of thousands of feet of water, in addition to all the subsurface geologic strata, puts immense pressure on the reservoir). In addition to producing large quantities of oil per well, off-shore wells tend to decline somewhat more slowly than many land wells. As a result, the off-shore segment of the industry is relatively slow moving. Once the money has been spent installing the infrastructure, the oil will be produced regardless of price fluctuations. In the same way, not committing capital to new development results in less production *years* in the future.

Unconventional, horizontal, hydraulically fractured wells are obviously significantly more expensive than conventional production. However, on a per-well basis, it is much lower capital expenditure than off-shore production. In addition, they come on-line much more quickly (usually 3-6 months vs 3-5 years); which has earned them the moniker "short-cycle" production. However, their production also declines much more quickly than other sources (see chart below).

All oil wells steadily decline in production as oil is extracted from the reservoir and the pressure depletes. Secondary and tertiary recovery methods can bump production up again, but they too will decline as oil is produced. Eventually, all reservoirs become depleted when no more oil can be economically extracted.




Source: IEA 2015 World Energy Outlook

## Refining

Crude oil contains a mixture of various types of hydrocarbon molecules. At normal atmospheric pressure and at room temperature, hydrocarbon molecules with 1-4 carbon atoms are usually gases. Those with 5-24 carbon atoms are usually liquids, and those with 25 or more are solid. These different molecules have different boiling points. The refining industry (also referred to as "downstream") is the process of using the varying boiling points to separate the crude into various products based on the number of carbon atoms they contain and is comprised of 3 basic steps: separation, conversion, and treatment.

Separation usually begins with desalting and dewatering the crude. Then continuous feed pipes move the crude oil through hot furnaces. The resulting liquids and vapors are discharged into distillation towers (usually the tallest columns in the refinery complex). Inside the distillation units, the liquids and vapors separate into petroleum components (also called "fractions") with heavy fractions on the bottom and light ones on top. The lightest fractions vaporize and rise to the top of the distillation tower, where they condense back to liquids. "Middle distillates" (such as kerosene and diesel) remain in the middle of the distillation tower, while the heavier liquids (also called "gas oils"), separate lower down in the distillation tower. The heaviest fractions settle at the bottom.

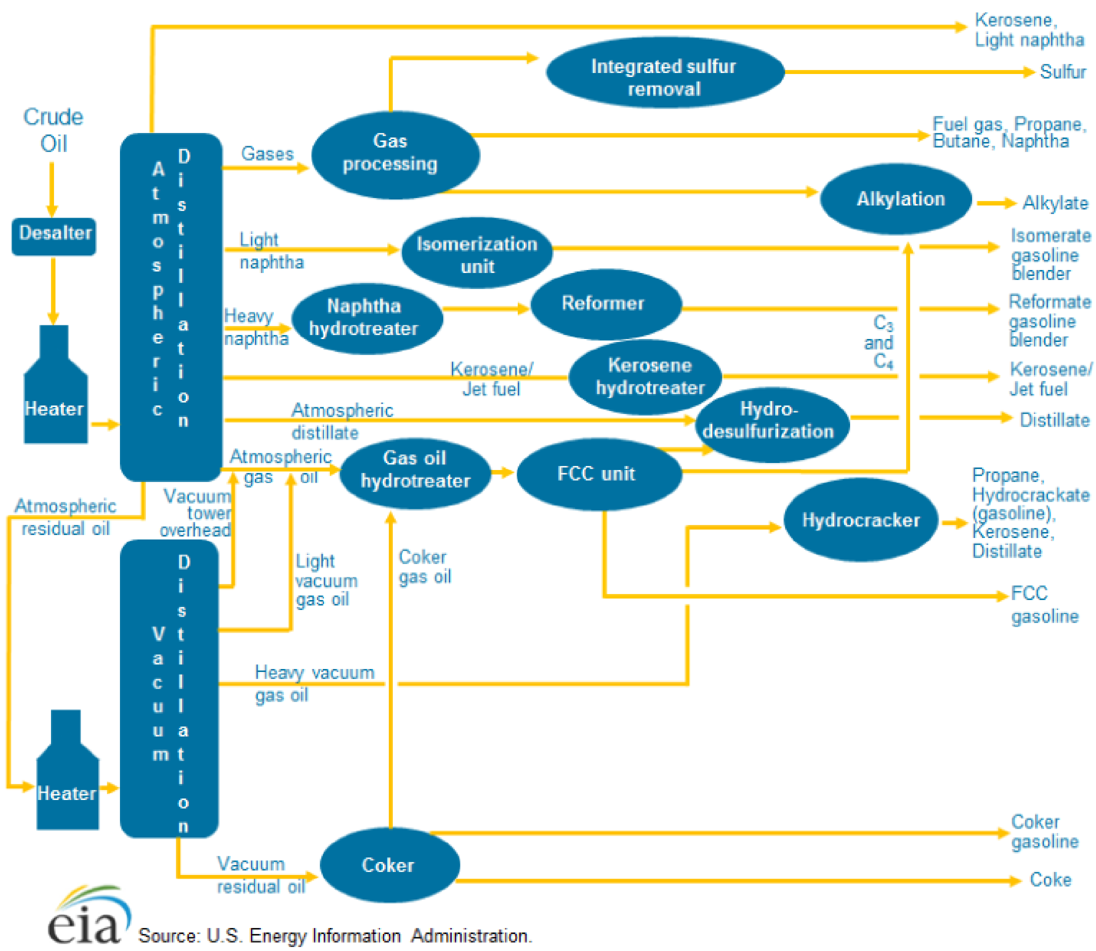
**Breakdown of crude oil**

| *Petroleum fraction* | *Petroleum product* | *Number of carbon atoms in molecules* | *Physical state** | *Approx. boiling temp.* | *Primary uses* |
|---|---|---|---|---|---|
| Petroleum gases | Methane | 1 | Gas | -161.6 °C | Heating/cooking, electrical power. |
| | Ethane | 2 | Gas | -88.6 °C | Petrochemicals, plastics. |
| | Propane | 3 | Gas | -42.1°C | Propane and butane together are called LPG when pressure liquefied for consumer use. |
| | Butane | 4 | Gas | -11.7°C | |
| Light ends | Naphtha | 5-11** | Liquid | 70°-200°C | Petrochemicals, plastics, solvents, blending for gasoline |
| | Gasoline | 7-10** | Liquid | 100°-150°C | Transportation fuel. |
| Middle distillates | Kerosene | 11-18** | Liquid | 200°-300°C | Jet fuel, lighting, cooking, heating. |
| | Distillate fuel oil/ Gas oil | 11-18** | Liquid | 200°-300°C | Diesel fuel, home heating oil. |
| Heavy ends | Lubricating oil | 18-25** | Liquid | 300°-400°C | Motor oil, transmission oil. |
| | Residual fuel oil | 20-27** | Liquid | 350°-450°C | Marine shipping fuel, electrical power, industrial fuel. |
| | Greases & Wax | 25-30** | Solid | 400°-500°C | Lubricants, candles and coating fruit. |
| | Bitumen | 35+** | Solid | 500°+ C | Road paving & roofing. |
| | Coke | 50+** | Solid | 600°+ C | Industrial fuel for steel production. |

*at standard atmospheric pressure and room temperature; **approximate range

After distillation, further refining takes place by converting lower-value distillation fractions into lighter, higher-value products (such as gasoline). "Conversion" is any process that separates, combines, or alters lower-distillate molecules (using heat, pressure, or catalysts) and transforms them into higher value products. This is where fractions from the distillation units are transformed into streams (intermediate components) that eventually become finished products. The process is sometimes called "upgrading."

Final treatment produces the products which are ready for sale. Refiners combine a variety of streams from the processing units. Final treatment may also include "hydroprocessing," which uses hydrogen to remove unwanted contaminants such as sulfur, nitrogen, and others. A gasoline blend, for example, is determined by the octane level, vapor pressure rating, and other special considerations.




A "crack spread" is the margin that a refiner is able to achieve by purchasing a specific grade of crude and turning it into finished products. It is the price of the finished products obtained minus the cost of the crude. Refiners will often hedge the spread between product outputs and crude inputs. For example, a typical crack spread is the 321 spread. To sell the spread a refiner would buy 3 crude, sell 2 gasoline, and sell 1 diesel or heating oil in the futures market.

**Transportation and Storage**

Oil is transported by tanker ship, pipeline, truck, railroad, or (primarily only in military operations) by aircraft. The oil transportation segment of the industry is often referred to as "mid-stream."

Wet cargo vessels (also known as "wet bulk carriers") carry crude oil and refined products. "Clean" tankers carry refined products and are generally smaller (and with shorter travel ranges) than "dirty" tankers, which carry crude oil, residual fuel oil, or bitumen. Roughly half of global daily production is transported by dirty tankers. "Deadweight tonnage" is the water displacement of a fully loaded ship minus the weight of the ship without any cargo, fuel, passengers, supplies, etc. A vessel that is fully loaded will sit in the water up to its "Plimsoll line" which is painted on the side of the vessel and indicates its legal safe submersion level. Given the opaqueness of the international oil market, a niche industry has developed around tracking dirty tankers (using human spotters, drones, satellite imagery, etc.) and estimating volume of oil on board by measuring how low the vessel is sitting in the water.

Ultra large crude carriers (ULCCs) and very large crude carriers (VLCCs) are the largest tankers available and carry between 200,000 and 560,000 deadweight tons. Because of their massive size and deep draft, they cannot approach port at many delivery locations, and off-shore delivery locations are used. For example, the Louisiana Offshore Oil Port (LOOP) can receive 1 million bpd of crude oil 18 miles off the Louisiana coast. Louisiana is currently in the process of retro-fitting the LOOP terminal to enable it to *export* crude, as opposed to only importing it. Currently, there are no export terminals in the US capable of loading ULCC or VLCC tankers. Any exported US crude carried on these vessels must be reverse lightered (carried by smaller vessels and transferred at sea to the larger vessel).

An important peculiarity to US law with respect to marine transportation is the Merchant Marine Act of 1920 (commonly known as the Jones Act). The private merchant marine (comprised of all US flagged vessels) is used to transport both imports and exports during peacetime and to function as an auxiliary to the Navy during times of war, delivering both troops and supplies. Incentivized by lower prices and fewer restrictions, ship owners had begun to register their ships under the flags of other nations, which led to fears of potential shortages of sealift equipment during wartime. The Jones Act created a demand for US flagged ships by requiring that any vessel moving cargo *between* US ports must be registered in the US (thereby ensuring the existence of an adequate merchant fleet). This has had a significant impact on all shipping, especially oil. At times, it may be cheaper to export crude from one port and import it to another, rather than pay the additional cost of transferring it via a US chartered tanker (although the Jones Act has been occasionally lifted in the aftermath of a Hurricane).

All oil, at some point, is transported through a pipeline. Collection (or "gathering") lines are generally smaller lines that consolidate streams of crude from collection points near the wellheads. Mainlines (or "trunk" lines) are large diameter pipes with few delivery points that transport oil long distances. Mainlines usually operate in "fungible" mode, meaning that the buyer receives the same type/quality of product as the seller, but not necessarily the same molecules. Short-haul lines, or "spurs," are of smaller diameter and primarily used for delivery. These lines usually operate in "batch" mode: meaning the buyer receives the exact same molecules that the seller put into the pipe.

Pipelines meet in locations called "hubs." Hubs generally have a large amount of storage capacity on site and are usually where price discovery occurs. For example, a major hub for US crude is Cushing, Oklahoma where the WTI crude oil contract is physically deliverable. Large centrifugal pumps (located every 20-100 miles) propel oil through pipelines at roughly 5 mph. When the crude is especially heavy, it is often combined with lighter hydrocarbons (or other chemicals) to speed up its flow. For instance, much of Canada's crude oil production is from extremely heavy tar-sands, which will not flow through transport pipelines at all without lightening it.

> NOTE: Any closed system which operates at capacity is constrained by its tightest bottleneck. An occurrence similar to the pipeline bottlenecks preventing natural gas from reaching the Northeast is also happening in the US crude market. Over the last 40 years the US has imported vast amounts of oil. The majority of this imported oil has been medium to heavy. Consequently, US refiners are set up (and optimized) to refine these heavier crudes. With the recent emergence of light shale production, the US was 1) not allowed to export it, and 2) not configured to refine it. These were bottlenecks in the system preventing it from efficiently getting to market. The removal of the export ban did not completely remove the bottleneck: the entire pipeline and port systems were configured to *import* oil not to export. The current $6 "spread" (price difference) between Brent and WTI (which are roughly equivalent grades) is incentivizing buyers to buy WTI, not Brent. Much of this spread, however, is eaten away by export transportation costs which are constraining exports and costing a transportation premium to buyers. This premium incentivizes transport operators to build new export capacity (both at the ports and in pipelines) – which they are doing, but this process takes time. In the same way, the crack spread is encouraging US refiners to refine more light US

> oil, which they are doing. But there are only so many low-cost switching options available to refiners, which they have already implemented. US refinery utilization rates are at all-time highs. For them to be able to process additional light oil would require billions of dollars of capital expenditure. We believe the export infrastructure is more likely to be built out before significant new light oil refining capacity is installed in the US.

Trucking is the most expensive (besides aircraft) transportation method and is typically only used for gathering operations at the well-head. Railcar, though cheaper than truck, is also very expensive. It is usually used as a last resort to move stranded barrels. For example, late in the shale boom (2013-2014), shale operators in the Bakken formation in North Dakota were extracting more light crude than they could transport by pipeline. Railroad was the only feasible method for transportation out of the remote basin. The premium paid to railroad operators incentivized pipeline operators to build more transportation lines to the region. The completion of those lines, combined with reduced activity from the recent bust in prices, has essentially ended all rail transportation out of the basin today.

As mentioned, most oil is stored near transport hubs. Storage (listed in order of increasing expense) is in underground caverns (usually salt caverns, formed by pumping water down into large salt domes in order to hollow them out), above ground tanks, tanker ships, and, on occasion, in parked rail cars. Above ground tanks often have floating roofs that sit on top of the oil. Similar to tracking crude shipping vessels, a cottage industry exists to estimate the amount of oil in storage around the world by measuring the shadows cast by the walls of the storage containers and estimating the height of the floating roof (further proof of the market's difficulty in knowing how much oil is in storage at any given time).

A base level of oil is required in pipelines and refineries simply for them to be able to operate. These systems generally operate 24 hours a day. For example, a pipeline must contain oil over its entire length – and this oil can never be removed without shutting down the pipeline. As demand, and production, increases, so too does the support infrastructure increase; and so does the minimum operating level of crude in the system.

Identifying the amount of crude in storage in the world is a herculean challenge. The mere existence of niche industries to estimate the amount of crude in storage speaks to the secrecy and mistrust prevalent in global economic (not to mention geopolitical) affairs. As mentioned, OPEC, the IEA, and the EIA all produce estimates (and all have their own unique biases as representatives of either producing or consuming countries). Despite these estimates, there is little "hard" data outside of western developed nations who report reasonably accurate, transparent storage numbers. The US, other OECD countries, and OPEC (as a group) also produce reasonably accurate production figures. However, all of this data, from all sources, is: 1) noisy (meaning that it may vary significantly in the short term and obscure the long-term trend), 2) delayed (usually by months, with the oldest data being the most accurate), 3) subject to frequent (and sometimes significant) revision, and 4) disparate (no one source has the complete picture). The net result is a tremendous amount of uncertainty around real-time global figures. As a result, the prevailing trend is much more instructive than the most recently reported value.

**Oil Markets**

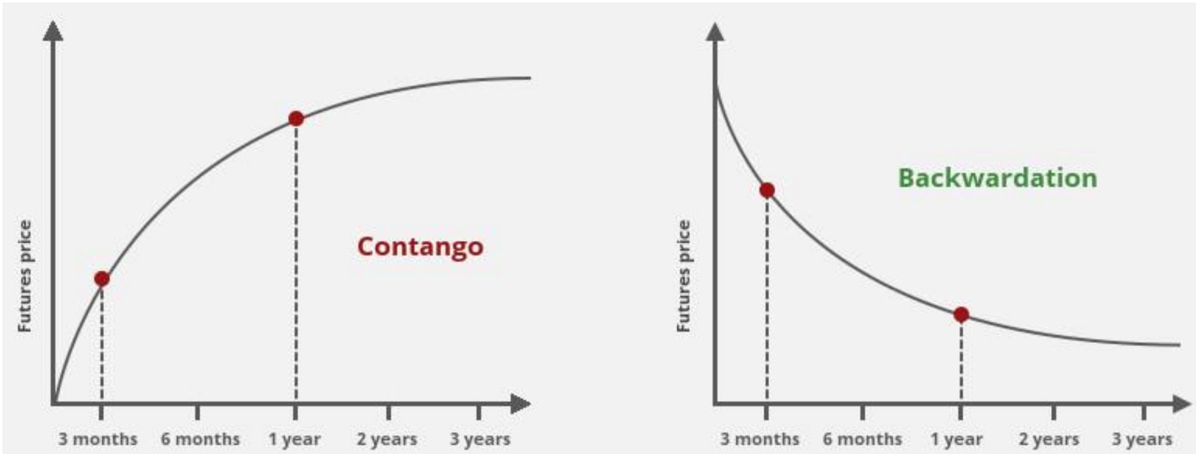
Like all markets, the fundamentals matter: supply must equal demand, *at some price*. In oil markets, "supply" means current production *plus* the change in storage. Therefore, the three primary fundamental drivers of oil's price are 1) Demand, 2) Production, and 3) Storage.

> NOTE: Any discussion of oil markets must include the fact that oil is mainly traded in US dollars. This makes sense given the US's history as the world's largest oil importer. Since oil is priced in dollars, oil and dollars are inversely correlated (as the dollar strengthens, oil price tends to fall – and vice versa). This relationship exists because, if a foreign currency can buy more dollars, then it can also buy more oil (oil becomes relatively cheaper, which increases demand). It is also important to note that, as the US's production has increased, its net imports have decreased. At the same time, China's consumption has increased and production has decreased (causing its net imports to increase). Currently, China and the US import roughly the same amount, but China may pull strongly ahead in future years. Consequently, oil may eventually become traded in Yuan as well as in Dollars.

However, the oil market is a complex adaptive system. Storage, Production, Demand, and Price are all dependent on each other *as well as* the market's expectation of all of their future values, *plus* the expected rate of change of all of their values. In addition, each variable has many other secondary and tertiary variables (such as governmental action, geopolitical events, natural disasters, etc.). Given the murky view of demand, production, and storage, it is no wonder that oil's current price (or "spot" price) can be quite volatile: it is the only thing that can be known with certainty at any given moment.

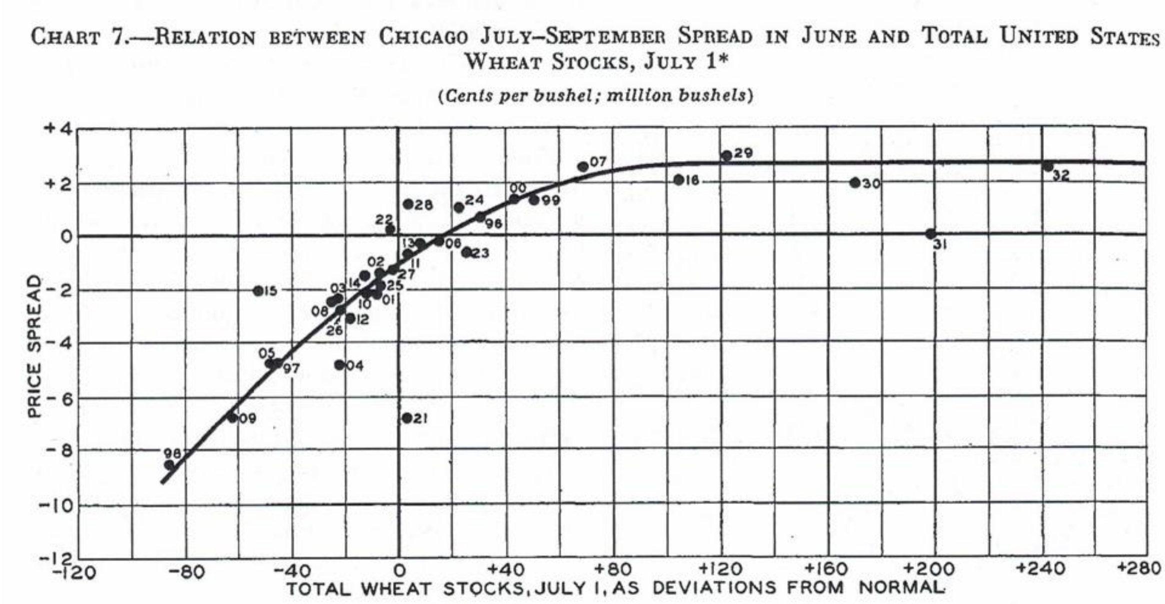
As discussed, there is a time lag between a producer's investment decision and the time of first production which can range from months to years. Many producers attempt to create certainty in their future revenue by selling their future production today (called "hedging"). In the same way, refiners (and other crude buyers) do not know what the future cost of their inputs will be. In order to create certainty in their future expenses, they may buy future production today. In this way, a "futures" market is created. Given the existence of a futures market, other players (such as speculators, arbitrageurs, and traders) are able to participate. The majority of contracts traded in the futures market are never actually held until physical delivery.

The prices of these "futures" contracts collectively are called the "forward curve." The forward curve can be in "contango" (which is upward sloping into the future), or in "backwardation" (which is downward sloping). Contango generally implies that current production is greater than current demand and incentivizes oil storage (one can purchase oil for delivery today and simultaneously sell it for delivery in the future and place it into storage upon receipt: Profit = Sales $\text{Price}_{\text{future}}$ – Purchase $\text{Cost}_{\text{today}}$ – Storage Cost). Backwardation usually occurs when current demand is greater than production (which incentivizes one to pull inventory out of storage and sell it today at a better price than in the future).



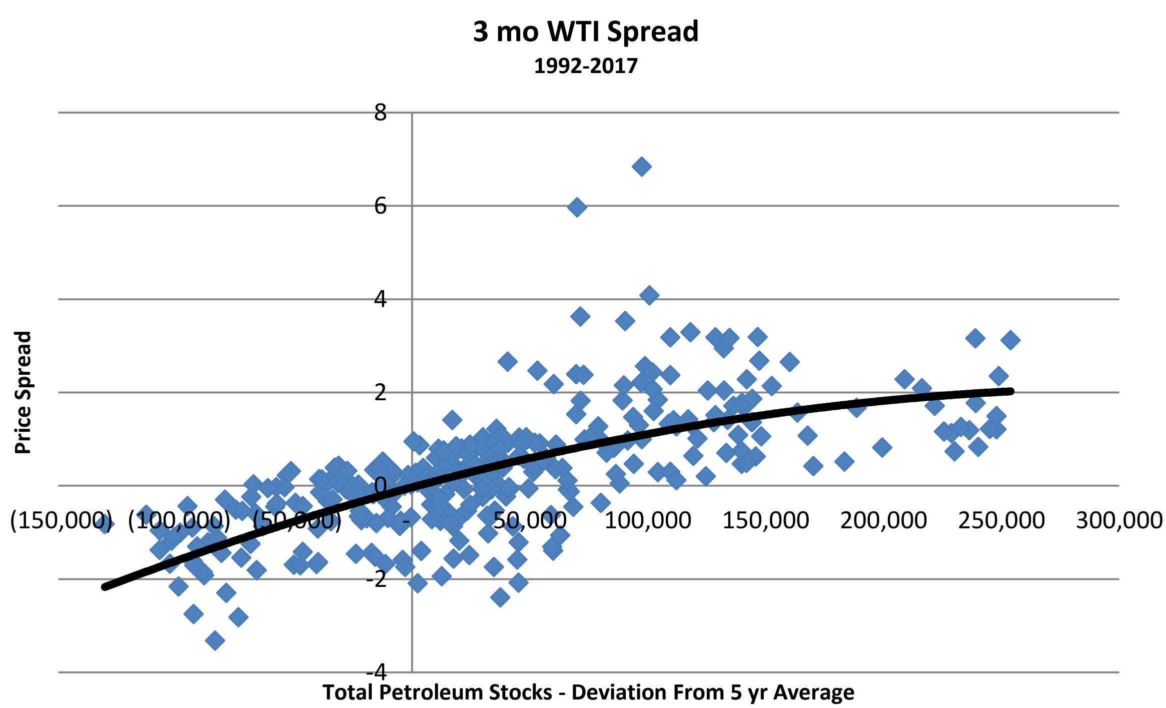

Over time, the forward curve flips back and forth between contango and backwardation. One factor that affects the *slope* of the curve is the availability (or shortage) of storage facilities. As storage facilities become scarce and the cost of storage goes up, the slope of the contango curve must steepen to incentivize traders to utilize more expensive storage options (such as ULCCs paid to sit at anchorage, or even to construct new storage facilities). Arbitraging the forward curve in this way is called a "carry" trade. Within oil markets, backwardation is generally more common than contango. This is likely due to at least two reasons. First, over the last 40+ years demand has, in general, steadily risen. For most of that period OPEC was maintaining spare capacity in order to manage price. In effect, OPEC was not producing what they *could have* produced and using their tapped reservoirs effectively as "free" storage containers. Second, arbitrageurs take the profit out of the curve. Using the carry trade is relatively simple, can be quite profitable, and is therefore very popular. By using it, traders create additional storage capacity, take profits, and reduce the slope of the forward curve. Backwardation, however, cannot be arbitraged away; production must increase (or demand decrease), which are slower processes.

Another way of describing it is that the slope of the forward curve is correlated to the level of storage. This is true of most commodity markets. For example, Stanford University published a research paper back in 1933 on wheat futures markets. It contained the graph below comparing the slope of the futures curve and the level of excess wheat in storage. The slope of the futures curve (or "price spread") defined as the 3rd month future price (in this case September) minus the front month price (July). Notice that anything above 0 on the Y axis represents contango (the future price is greater than the present price), and backwardation is below 0. As storage levels approach average levels (0 on the X axis), the price spread becomes much more responsive (it crosses from contango to backwardation).




Source: https://ageconsearch.umn.edu/record/142876/files/wheat-1933-03-09-06.pdf

We continue to see the same pattern in commodity futures markets 85 years later. It is instructive that, despite the mind-boggling changes to the world witnessed over the last century, some things are not much different. See the below graph of the oil futures market and note its similarity to the wheat graph above. It incorporates many more years of data, but the relationship between the price spread and excess storage is the same. We may only definitively know prices, but they (and their time spreads) are an indication of the interaction taking place between supply and demand (i.e. the change in storage).



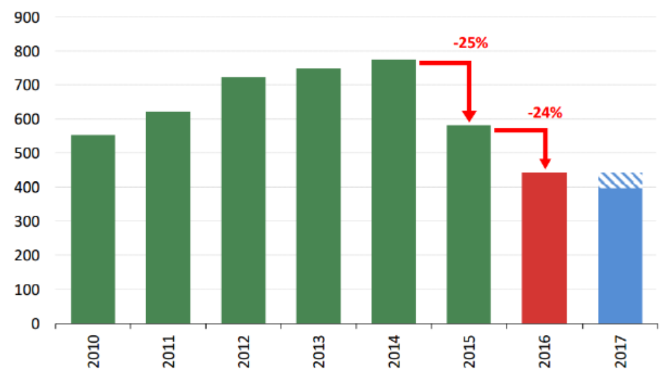

Source Data: EIA, Bloomberg, Baines Creek Capital

## The Current Environment

As demonstrated in the first section of this paper, over the last 2 centuries mankind has extracted the easiest to access (and therefore the cheapest) oil resources on our planet. These easy-to-extract reserves are becoming depleted, how much remains in the ground is uncertain. We are finding less conventional oil today than we have in over 50 years. Consequently, conventional production is declining. Only more difficult and expensive to extract resources remain for future development (such as off-shore, shale, tar-sands, and yet to be discovered future resources). Compounding this effect, the recent downturn in prices has significantly reduced investment in both exploration and long-cycle high-cost production projects (see the two charts below). By the end of 2018 there will be very few large production projects (whose investment decision was made 3-5 years prior) nearing completion. Consequently, the next 3-5 years' growth will depend almost entirely on OPEC and short-cycle shale projects. Meanwhile, demand has relentlessly risen. Over the long term, constrained supply coupled with increased demand will result in higher prices (the recent run-up in prices notwithstanding).

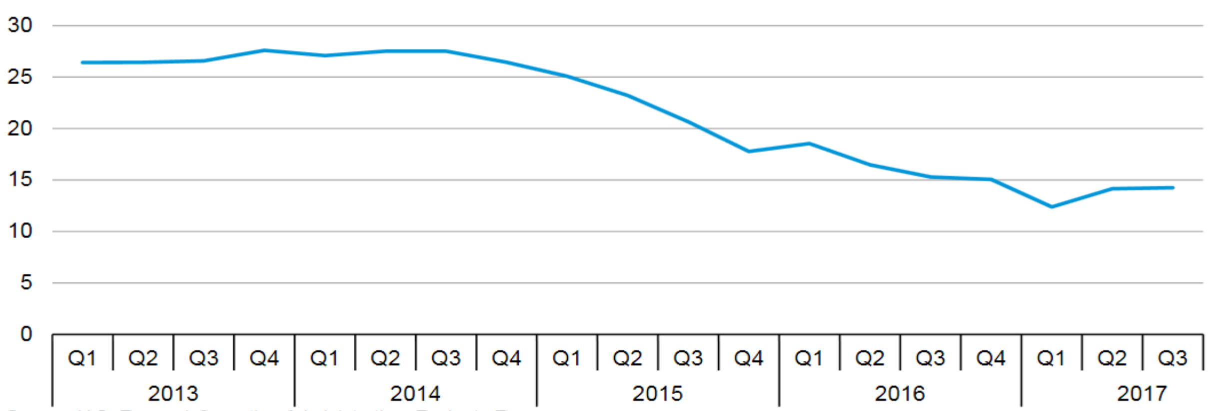
**Figure 15. Global Upstream Capital Spending 2010-2017**

*(in billions of 2015 U.S. dollars)*



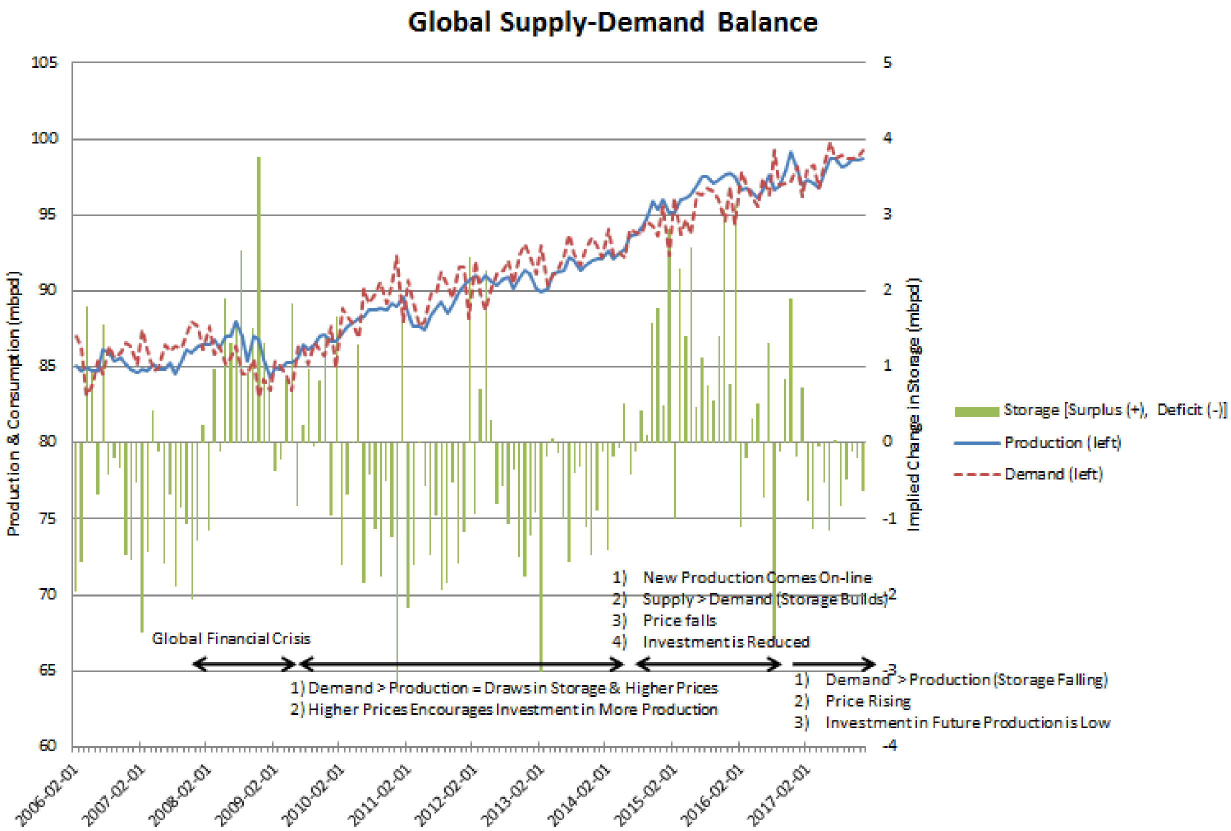

Source: International Energy Agency *World Energy Investment* 2016.

upstream capital expenditure per barrel of oil equivalent produced
2017 $/boe four-quarter moving average




*Source: U.S. Energy Information Administration, Evaluate Energy*
*Note: boe=barrel of oil equivalent*

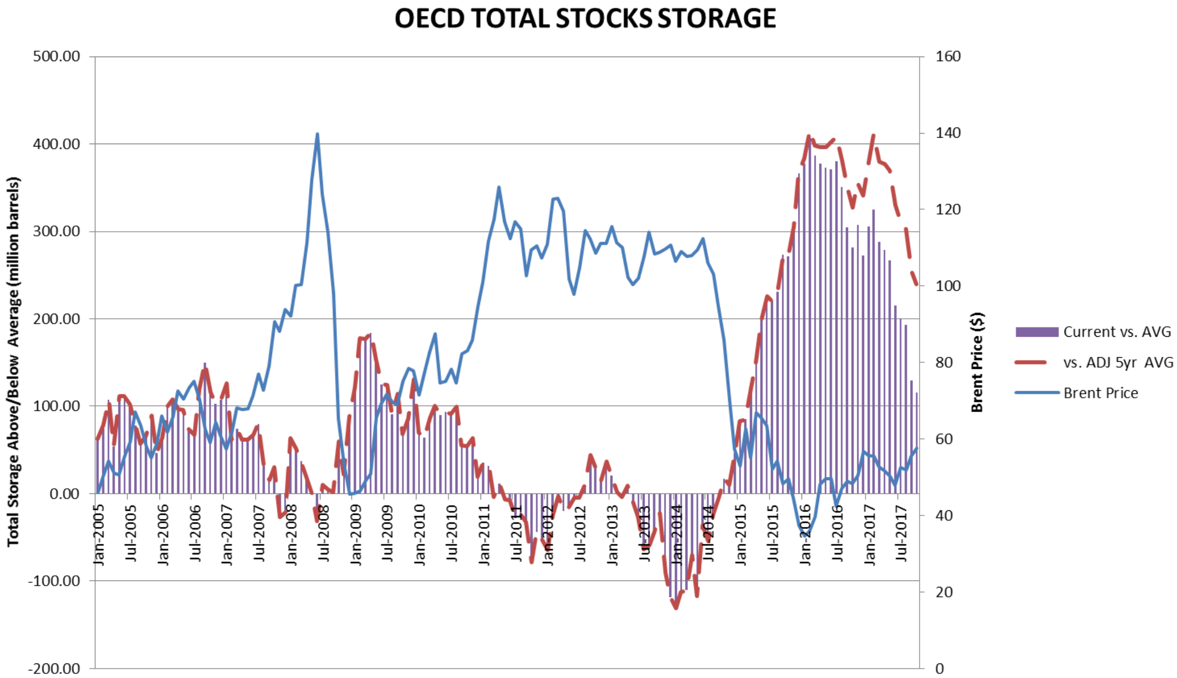
Over the short term, storage levels expand and contract in response to both price and the difference between production and demand. As discussed above, price becomes more responsive as storage approaches (or dips below) "normal" levels. (The running 5 year average is generally considered the "normal" level). Storage acts as a shock absorber for the market. Given an unforeseen spike in demand (or a production outage), the storage is readily available to meet demand without price needing to rise significantly. However, when stores are low, then there is no shock absorber; price is the only mechanism to cause supply and demand to balance. The next chart graphically displays this relationship over time. When demand is greater than production, stores fall (and vice versa).



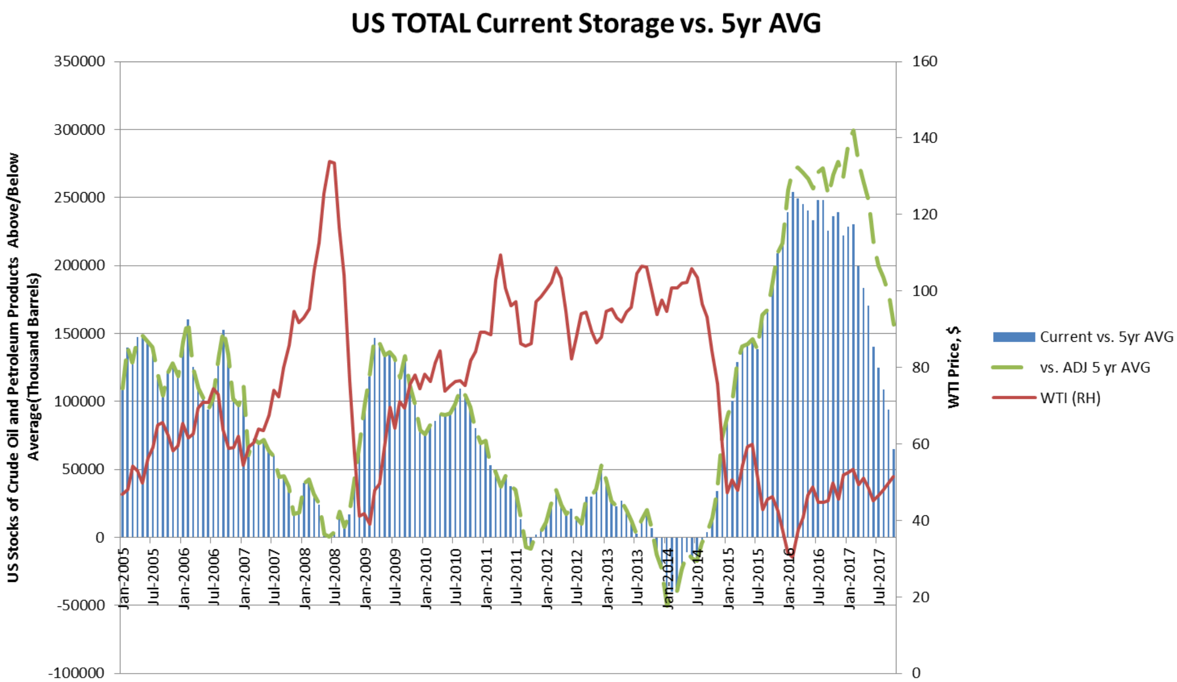

Source: EIA, Baines Creek Capital

Western, developed, capitalistic, countries are the only ones that produce publicly available, consistent, and reasonably reliable storage figures. (NOTE: This implies that the market will likely become more difficult to judge as China, India, Brazil, and other emerging markets grow to become, as a group, more dominant than the US - unless they begin to publicly produce reliable data.) The US and total OECD storage data are detailed in the graphs below. Storage above/below the five year average is graphed alongside of the respective price (WTI is the benchmark for the US, and Brent is the European benchmark). Note the inverse relationship: as storage declines, prices tend to rise – and as storage rises, price declines. Since refiners are the primary buyers of crude and since demand for refiner's products are the primary driver for the demand for crude, *total* petroleum storage (crude + refined products) are the storage levels that most impact the price of crude.

> NOTE: Refer back to the OPEC + Russia production graph on page 11. Notice the large increase in production in late 2016 (in their ramp-up right before they "cut" production). This bump in production correlates directly with the second peak in OECD storage in early 2017 (first graph below). OPEC increased production in order to be able to "cut" from a higher level. This increase went directly into storage, increasing the total amount of excess storage that needed to be worked off.




Source: IEA, Bloomberg, Baines Creek Capital



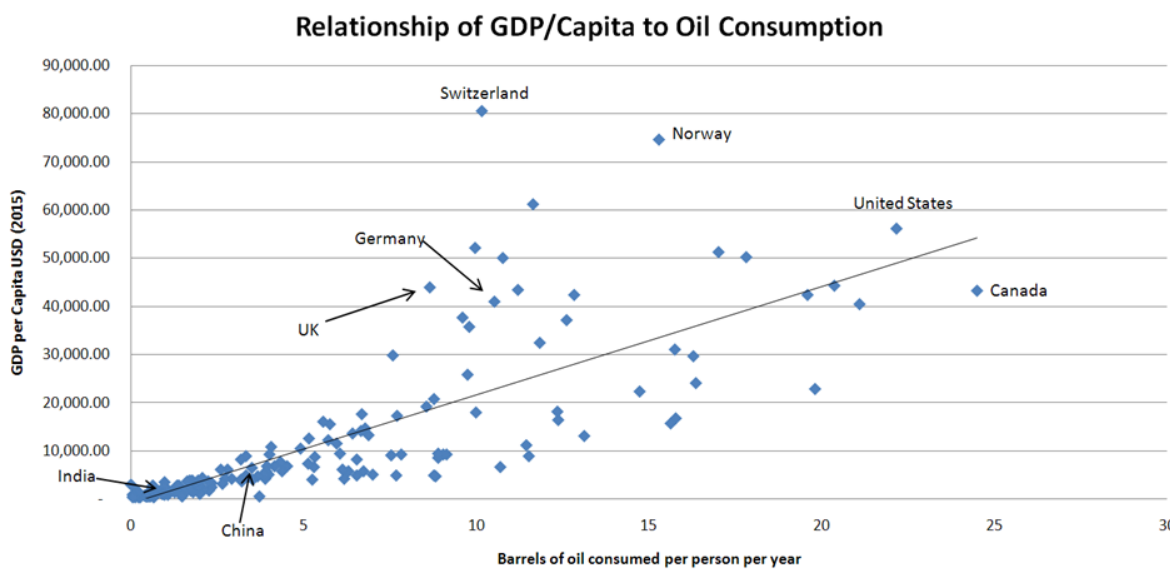

Source: EIA, Baines Creek Capital

Besides the relationship of storage levels to price, what is clearly seen is the rapid reduction in storage inventories over the last year. The magnitude of the storage peak is impressive, but the rapid decline from that peak is equally impressive. Recalling the previous discussion about uncertainty in real-time figures, please note that the recent trend in storage is strongly downward (and that the most recently reported figures are for October 2017). <u>There can be only one conclusion: over the last year demand has been much larger than production, resulting in excess demand being met by a reduction in inventories.</u> Some observers, claim that the 5 year average is inflated by the magnitude of the recent storage peak. However, the "adjusted" 5 year average is falling at an equally impressive rate. Furthermore, the Brent forward curve has been in backwardation for some months now, while WTI has recently flipped to be entirely in backwardation (in late 2017). This is yet another indication that demand is greater than production and that stores are close to normal levels. (For clarity, backwardation itself is not the indication; it is the *change* from contango to backwardation. At the price lows in early 2016 the futures curve was strongly in contango. Over the last 2 years it has been slowly flattening and is now in backwardation.)

Other observers believe that the reduction is entirely due to OPEC cutting production and that as soon as price rises they will bring additional supply flooding back. While increased prices may incentivize OPEC to produce more, we are very skeptical of this argument. OPEC is producing now at the rate they were immediately before the "cut." They are producing today above their 2016 production rate – and much above 2013, when prices were far higher. Finally, they have been suffering the effects of low prices along with the rest of the industry. All industry reports (most notably, Western service providers that work for OPEC NOCs) have been of severely reduced capital expenditure budgets. This stands to reason: their oil-dependent economies are painfully stretched by the downturn. It is reasonable that, as prices rise, they use the additional revenue to catch-up on deferred maintenance, refill the national coffers, and relax budget constraints on social welfare programs before they invest in expanding production. It does not appear that OPEC is actively preparing to flood the market with oil – unless it is from hidden storage.

Will demand remain strong? It is relatively unusual for no major economy to be in recession at any given time. 2017 was one of those rare times. We believe that this unusual circumstance is not a new normal for the world: economic contractions will occur again. Predicting precisely *when* is much more difficult – and is not a task that we can consistently get right over long periods of time (and therefore don't attempt to). China's growth rate moderated somewhat over the last year (but is still very impressive). India's growth also slowed somewhat, although this *may* have been a one-time event caused by the government's attempts to fight fraud by controlling the currency denominations in circulation. Economic indicators appear to be quite healthy in the US. What concerns us is that nearly all economists are predicting growth – when everyone says the same thing, we usually begin to wonder. All that said, over the long term, as economies grow their oil demand grows with them.

Historically, there has been a relatively consistent relationship between GDP and oil consumption (see graphic below). As GDP increases, so does oil consumption.

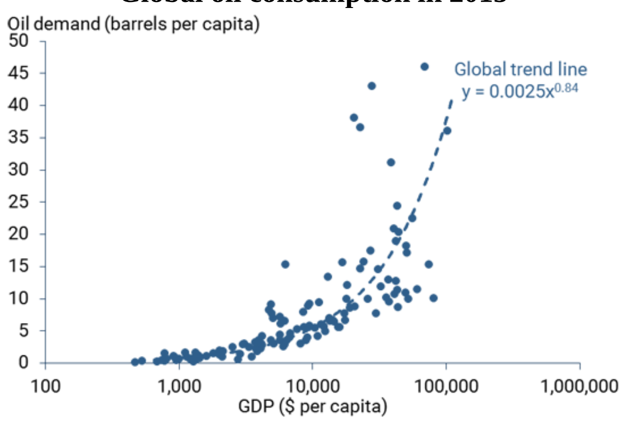



Sources: EIA, IMF, Baines Creek Capital

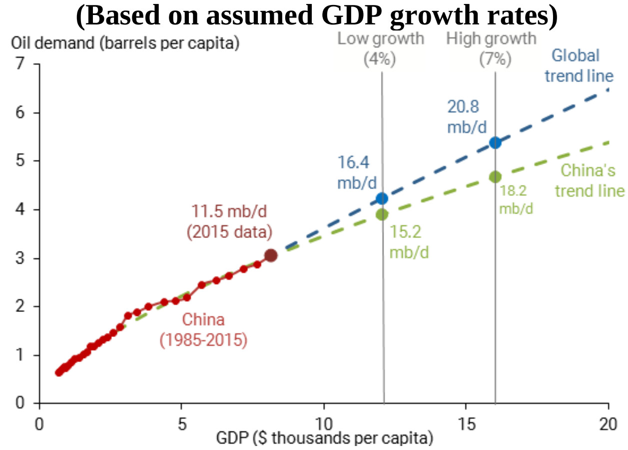
NOTE: As China (and India's) middle classes expand in the coming years, and their GDP per capita rises, so too will their oil consumption. China, with its large population, is likely to dominate future oil demand growth. Also note both the UK and Canada: they have relatively similar GDP per capita but vastly different consumption per person. This is most likely the effect of a small, densely packed nation relative to a large, geographically dispersed one. While home to some of the largest cities on earth, China is more geographically similar to Canada than it is to the UK.

The above graphic, assumes a *linear* relationship. But the Federal Reserve estimates that the GDP per capita to oil consumption relationship is not linear – it is *exponential*. Research from the Federal Reserve Bank of San Francisco in 2015 estimated that China's oil consumption could nearly double by 2025 (see charts on the next page). This would require incremental production equaling *another entire* US, Saudi Arabia, or Russia. Even if their growth slowed to 4% (verses the 6.7% estimated for 2017), the world would need to produce an *additional* 4 million barrels/day *just for China*. That represents an additional 40% of Saudi Arabia's production. The world is going to need a lot of additional oil in the coming years just to meet China's growing population needs, not to mention the rest of the world. Norway may mandate that all vehicles sold in 2040 must be electric, but if the Federal Reserve Bank of San Francisco is even *half* right, then price must rise dramatically in the near term to incentivize increased production.

**Global oil consumption in 2015**

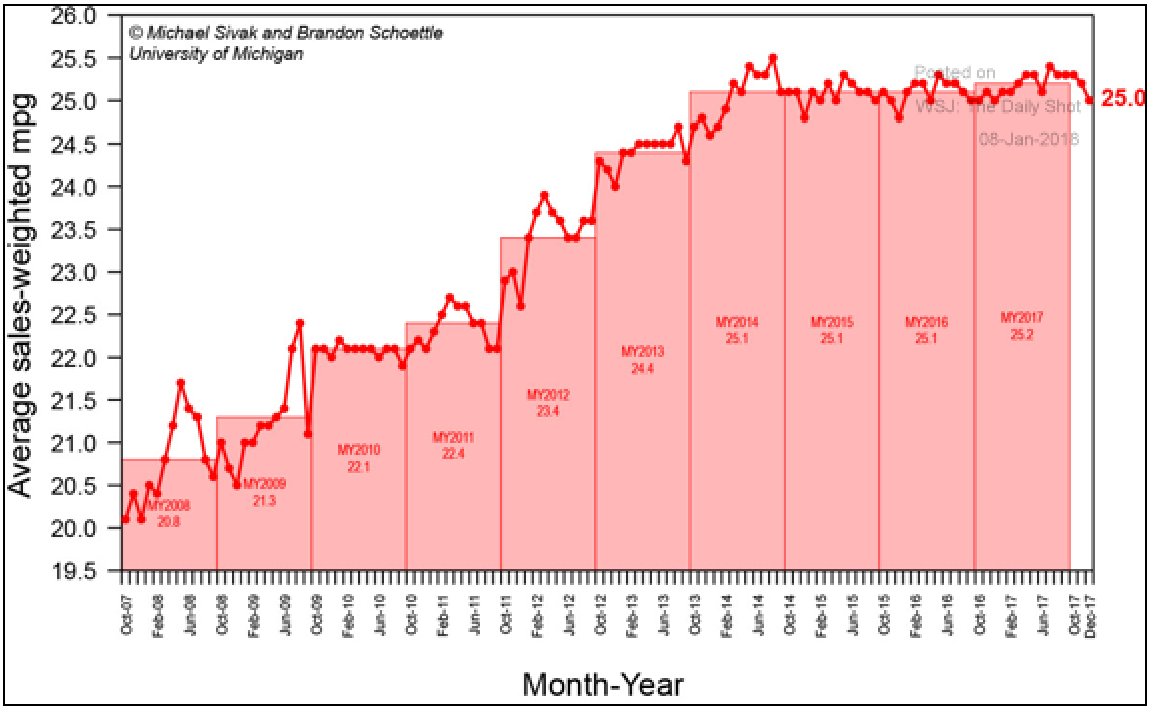



**China's Oil Demand in 2025**
**(Based on assumed GDP growth rates)**



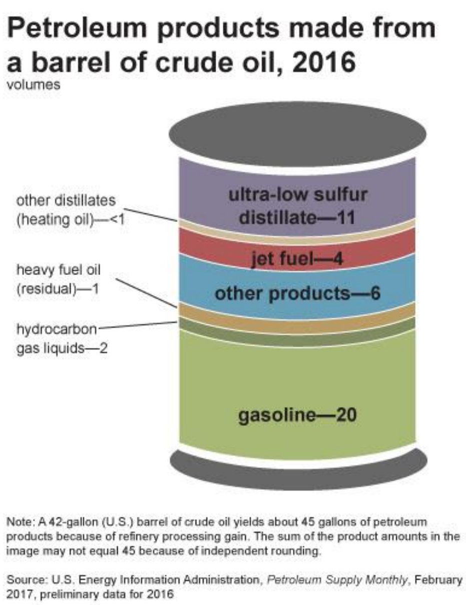

Source: https://www.frbsf.org/economic-research/publications/economic-letter/2017/august/forecasting-chinas-role-in-world-oil-demand/

Also, the reduction in fuel prices has, once again, changed consumer's habits. The graph below from the University of Michigan (reported by the Wall Street Journal) demonstrates how the growth in US fuel-efficiency stalled after prices fell in 2014. We believe fuel-efficiency gains will accelerate in the future, but only after high fuel prices incentivize the growth. Consumers prefer the gas-guzzler, if they can afford it (the prestige of Tesla notwithstanding).




Source: Wall Street Journal

Will oil demand be destroyed by technological innovation? The two major hurdles with finding a replacement for oil are 1) storage, and 2) production.




**Substitutes for oil**

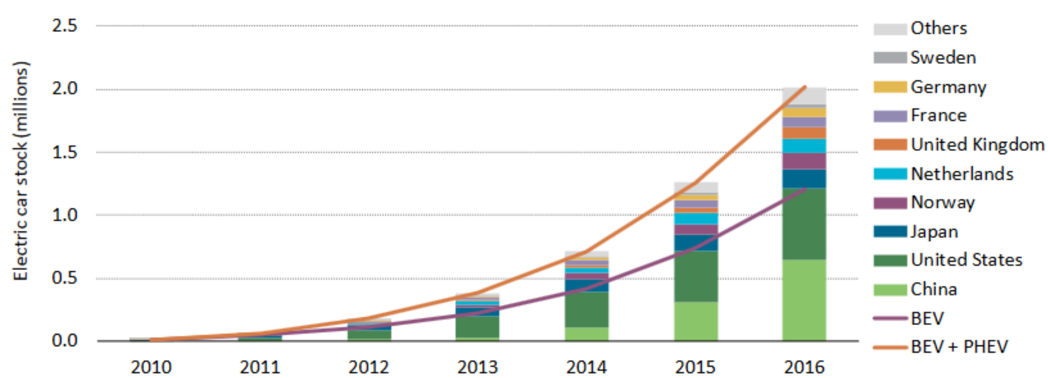
| *Petroleum fraction* | *Petroleum product* | *Primary uses* | *Substitutes* |
|---|---|---|---|
| Light ends | Naphtha | Petrochemicals, solvents, blending for gasoline | None |
| | Gasoline | Transportation fuel. | Electric Vehicles |
| Middle distillates | Kerosene | Jet fuel | None |
| | Distillate fuel oil/ Gas oil | Diesel fuel | None |
| | | Home heating oil | Natural Gas |
| Heavy ends | Lubricating oil | Motor oil, transmission oil. | Synthetic oil |
| | Residual fuel oil | Marine shipping fuel | Liquified Natural Gas (LNG) |
| | | Electrical power* | Natural Gas* |
| | | Industrial fuel | None |
| | Bitumen | Road paving & roofing. | None |
| | Coke | Industrial fuel for steel production. | Coal |

*Natural Gas has already substituted away the majority of global electricity production. Only several percent of the world's electicity is still produced by burning oil products. It is most common in OPEC countries, and is usually petroleum coke and residual fuel oil that is burned. Very little raw crude is burned today for electricity generation.

As the above graphics demonstrate, oil is predominantly turned into transportation fuels. There are very few alternatives to petroleum products, especially as a transportation fuel. Any replacement for it must be relatively lightweight and compact. To date, battery powered electric vehicles (EVs) are the most likely candidate to be this disruptive technology for gasoline (which is the largest product by volume from a barrel of oil).

Some argue that EV disruption has arrived – the disruption is occurring *now*. That may be true. It is very likely that EVs (or something similar) eventually replace internal combustion engines. However, we question the assumptions of how long the transition will take. The primary arguments against the rapid adoptions of EVs are: battery cost (largely driven by potential scarcity of components), lack of charging station infrastructure, lack of copper (replacing the world's entire fleet of internal combustion engine vehicles with EVs could exhaust the world's known copper supplies), the potential strain on the electric grid and the increased utility scale power demand. However, for simplicity, let's take a mathematical approach. The IEA recently published a "Global EV Outlook" in 2017. EVs are posting some impressive growth rates:

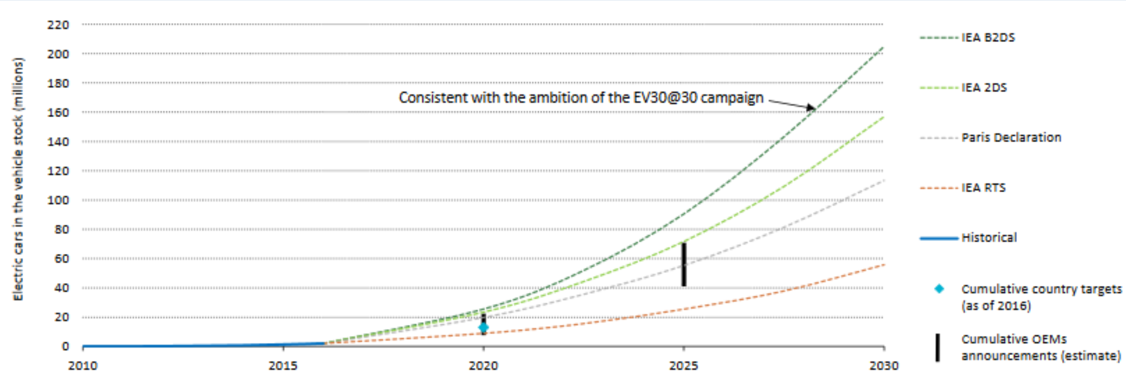
**Figure 1 • Evolution of the global electric car stock, 2010-16**




Notes: The electric car stock shown here is primarily estimated on the basis of cumulative sales since 2005. When available, stock numbers from official national statistics have been used, provided good consistency with sales evolutions.

Sources: IEA analysis based on EVI country submissions, complemented by EAFO (2017a), IHS Polk (2016), MarkLines (2017), ACEA (2017a, 2017b) and EEA (2017).

**Figure 2 • Deployment scenarios for the stock of electric cars to 2030**




Source: IEA (https://www.iea.org/publications/freepublications/publication/GlobalEVOutlook2017.pdf)

Those are some astonishing growth rates! What the entrepreneurs, engineers, technicians, and businessmen are accomplishing is very impressive. They should be very proud of their hard work and deserve the praise they have been getting. However, a little perspective is needed. Let's assume that the IEA's very best case scenario in the graphic above is a reality (about 200 million electric cars on the road in 2030). In 2015 there were approximately 1.25 *billion* cars on the road worldwide. Let's also assume that total cars on the road increases along with inflation at 2% (a conservative assumption since vehicles on the road have been growing over 3% per year over the last 15 years):

It is remarkable to note the fact that, under this extremely optimistic scenario for EV adoption, in 2030 there will be *more* internal combustion engines than there are today (over 200 million more!). Even in this hypothetical scenario *plus* efficiency gains, a transition to smaller vehicles, and change in driving habits (carpooling, etc.), it seems extremely unlikely that crude demand will decline over the next 15 years. However, that scenario is excessively unrealistic. According to the World Bank, the globe's GDP growth has averaged 2.5% growth over the last decade (which includes the Global Financial Crisis). The International Monetary Fund (IMF) estimates that the world's GDP growth has been 3.34% over the last 10 years (and projects 3.74% average annual growth over the next 5 years). Assuming they are reasonably accurate (simply for the sake of argument), then a global GDP growth rate of 3% is a reasonable estimate.

| **2% Vehicle Growth Scenario** | | | |
|---|---|---|---|
| **Year** | **Total Vehicles** | **Electric Vehicles** | **% Electric** |
| 2015 | 1,250,000,000 | 1,250,000 | 0.10% |
| 2016 | 1,275,000,000 | 2,000,000 | 0.16% |
| 2017 | 1,300,500,000 | 5,000,000 | 0.38% |
| 2018 | 1,326,510,000 | 10,000,000 | 0.75% |
| 2019 | 1,353,040,200 | 20,000,000 | 1.48% |
| 2020 | 1,380,101,004 | 25,000,000 | 1.81% |
| 2021 | 1,407,703,024 | 40,000,000 | 2.84% |
| 2022 | 1,435,857,085 | 48,000,000 | 3.34% |
| 2023 | 1,464,574,226 | 60,000,000 | 4.10% |
| 2024 | 1,493,865,711 | 72,000,000 | 4.82% |
| 2025 | 1,523,743,025 | 90,000,000 | 5.91% |
| 2026 | 1,554,217,885 | 108,000,000 | 6.95% |
| 2027 | 1,585,302,243 | 130,000,000 | 8.20% |
| 2028 | 1,617,008,288 | 156,000,000 | 9.65% |
| 2029 | 1,649,348,454 | 180,000,000 | 10.91% |
| 2030 | 1,682,335,423 | 200,000,000 | 11.89% |

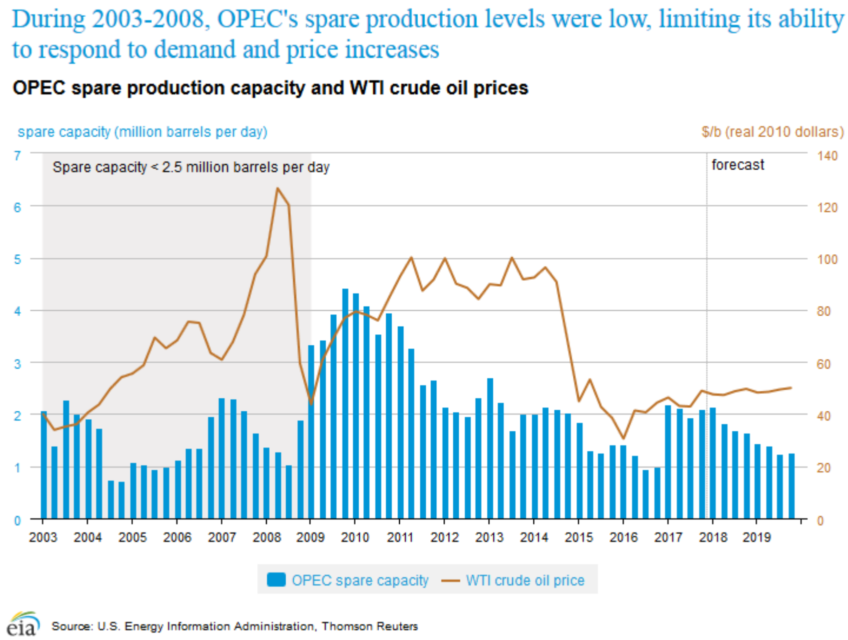
Using 3% as the global GDP growth rate, and keeping the IEA's best case scenario for EVs, the above chart now looks like this:

| **3% Vehicle Growth Scenario** | | | |
|---|---|---|---|
| **Year** | **Total Vehicles** | **Electric Vehicles** | **% Electric** |
| 2015 | 1,250,000,000 | 1,250,000 | 0.10% |
| 2016 | 1,287,500,000 | 2,000,000 | 0.16% |
| 2017 | 1,326,125,000 | 5,000,000 | 0.38% |
| 2018 | 1,365,908,750 | 10,000,000 | 0.73% |
| 2019 | 1,406,886,013 | 20,000,000 | 1.42% |
| 2020 | 1,449,092,593 | 25,000,000 | 1.73% |
| 2021 | 1,492,565,371 | 40,000,000 | 2.68% |
| 2022 | 1,537,342,332 | 48,000,000 | 3.12% |
| 2023 | 1,583,462,602 | 60,000,000 | 3.79% |
| 2024 | 1,630,966,480 | 72,000,000 | 4.41% |
| 2025 | 1,679,895,474 | 90,000,000 | 5.36% |
| 2026 | 1,730,292,338 | 108,000,000 | 6.24% |
| 2027 | 1,782,201,109 | 130,000,000 | 7.29% |
| 2028 | 1,835,667,142 | 156,000,000 | 8.50% |
| 2029 | 1,890,737,156 | 180,000,000 | 9.52% |
| 2030 | 1,947,459,271 | 200,000,000 | 10.27% |

In this scenario, there will be nearly 500 million more ICE cars on the road than in 2015. We have no way of knowing what scenario will play out. But, if the world gets really ambitious about transitioning away from fossil fuels as a transportation energy source, it appears that we will have to do much, much more than is currently anticipated *in the best case*. Therefore, the most probable future outcome is that crude demand will continue its steady climb higher.

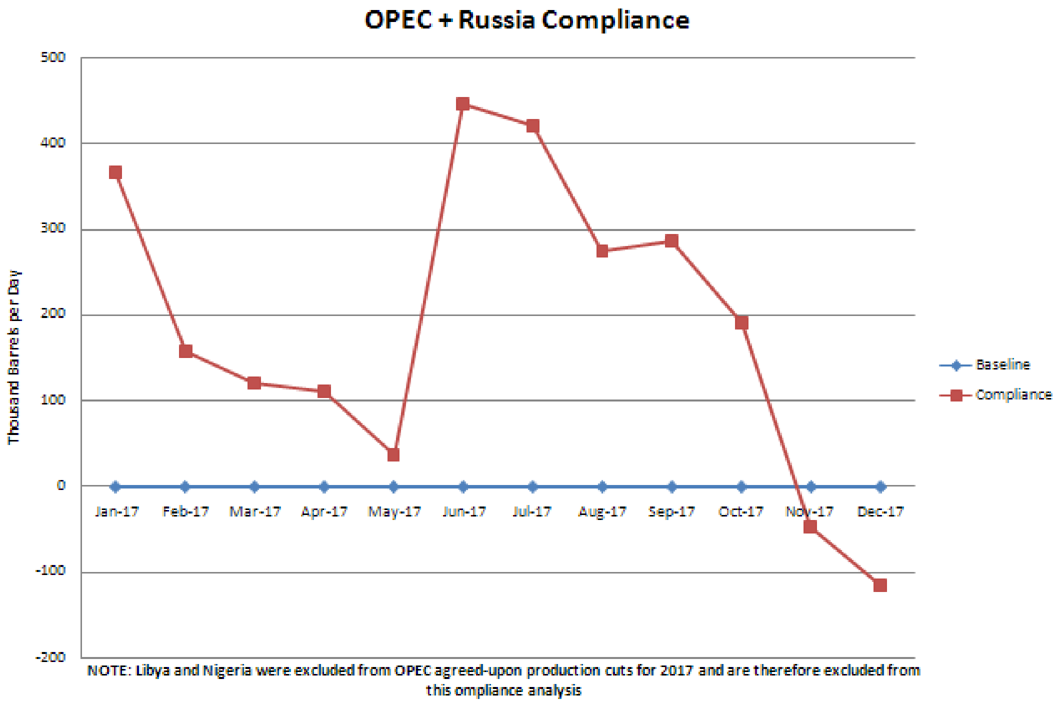
Since storage is nearing the 5 year historical average and long-term demand is likely to continue to trend up (so long as long-term GDP continues to trend up), can production increase to fill the future supply shortfall?

Currently, the world's oil production can be thought of as belonging to three groups. Understanding their motivations is an important key to understanding the likely course of events in the oil market. The first group is OPEC & Russia (representing roughly 40% of the total). OPEC (especially Saudi Arabia) has shown a desire to consistently manage the price of oil for their own *long-term* benefit. Most OPEC nations (and arguably Russia) have strong authoritarian governments who desire to stay in power; managing their oil revenue is an important element in achieving that goal. During this period of constrained budgets, they do not appear to have been investing much (if any) on increasing their spare production capacity. The second group is US land operators, who collectively are about 8% of the total. Within this group, it is specifically the unconventional shale producers who will be able to generate most of the United States' near-term growth. The amount of production they will bring on-line (and for how long) represents significant uncertainty in the market. The final group is the rest of the world; represented largely by International Oil Companies and the remaining National Oil Companies outside of OPEC. This group seems to be focused primarily on cash returns (either to their shareholders or governments). They have been maximizing production and minimizing expenses. To this end, they have been riding the tailwind of previous investments coming on-line and limiting investment to short-term, low-cost, low-risk projects. Doing this has enabled them to keep production relatively flat while cutting their workforce and expenses. This strategy, while financially sound in the short-term (although cutting the dividend could *arguably* be wiser), at some point they will need to invest again in large-scale projects; and those investments will take time to come on-line. It appears that, in the near-term, any growth will likely come from US shale production and what remaining excess capacity OPEC producers have available.




Although the actual spare capacity of OPEC members is unknown, the above chart shows the EIA's estimate over time. Notice that, at present, OPEC has excess spare capacity of approximately 2 mbpd. This is a relatively low figure. It is approximately what OPEC's spare capacity was in the early 2000's when the price started to rise. However, it is relatively less than it was then. Demand in early 2003 was almost 80 mbpd, today it is approximately 98 mbpd. 2 million barrels of excess capacity then was more than it is today (2.5% of the total, vs. 2% today). For comparison, in 1985 OPEC spare capacity was roughly 10 mbpd while demand was about 60 mbpd, or almost 17% of total consumption. It is possible for OPEC to un-choke their wells and produce above the optimal recovery rate. But they would not be able to do this for long and would damage the long-term production capacity of the reservoir. Furthermore, OPEC was only producing 18 mbpd in 1985 and is producing nearly 39 mbpd today.

It is also telling that OPEC's compliance with agreed-upon "cuts" increased throughout 2017 (see chart below). There is a notable peak during the summer as OPEC members increased production to meet their summer electricity (for air conditioning) demand. However, the trend throughout the year is downward. Part of the increasing compliance was due to Russia implementing their cut gradually throughout the first half of the year. But the effect could also be an indication of lack of investment and allowing natural declines to take their effect. The UAE, Kuwait, Saudi Arabia, and perhaps Russia, are the only ones who we believe can meaningfully increase production. Others, like Venezuela, are unlikely to even slow their decline in the near-term. OPEC nations (and NOCs in general) usually manage for cash returns; it is the lifeblood of their economies. Consequently, when prices go down, they are incentivized to produce more in order to keep revenue constant. In the same way, as prices rise, they have less economic incentive to quickly produce more (they are less desperate for cash and can be more measured in their approach).



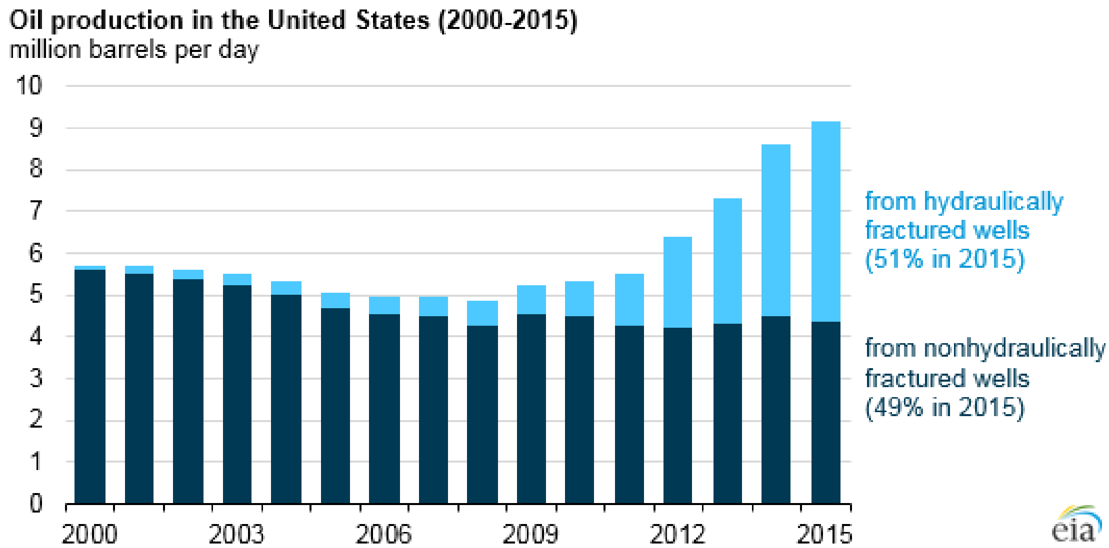

Source: OPEC, EIA, Baines Creek Capital

When OPEC ends their production "cut" at the end of 2018 (give or take), they will have much less production available to bring on-line than in the past. They, more than anyone else, are aware of their own ability to meet future demand growth. They also recognize that investors will not make investments in long-term, high cost, exploration and production projects without the confidence that they will be able to make a return on their investment – and these investments are needed today in order to meet the expected demand in the future. OPEC appears to be continuing to attempt to manage the market for the long-term. They have "cut" at historically high production rates and appear content to let global inventories decline (and price to rise) while they maintain their production rates. It appears unlikely that they have any incentive (or sustained ability) to flood the market with massive amounts of crude. If anything, it is more likely that they want the market to have confidence in higher prices so as to 1) receive more revenue, and 2) encourage investment so that prices do not spike excessively, thereby causing another crash.

That leaves shale production. Will it come roaring in, flooding the market causing another crash? The rapid expansion of U.S. shale oil production beginning in 2009 was immediately preceded by a contraction in shale gas drilling at the end of 2008 (see graph below). Because shale oil production and shale gas production use the same rigs and hydraulic fracturing equipment, the industry was able to transfer equipment idled by gas drilling to shale oil, which facilitated the rapid growth of U.S. shale oil production. Since the oil price crash in 2014, the oil rig count has declined dramatically. As US shale is needed to help meet future demand growth, a future surge in shale oil production, similar to the one between 2009-2014, will be dependent on the extent to which the recently idled drilling and fracturing equipment has been maintained, cannibalized for parts, or scrapped since June 2014. It will not be as easy as it was in 2009. Bringing new (or refurbished) equipment to market in the future will require capital investment that was not required then. Investors expect a return on capital; therefore it is reasonable to expect drilling and fracturing costs to rise from current levels (the discounts that producers received from servicers during the downturn will be temporary). This effect was seen not only in equipment, but also in skilled labor to operate it. Massive layoffs dispersed this skilled labor to other industries, which will also likely increase future production costs above those required in 2009.


Source: Baker Hughes weekly rig count, Baines Creek Capital

Besides the changes in the oilfield services sector, crude prices were in the $90-$100 range (inflation adjusted) from 2009-2014 coupled with easily available, cheap credit. Even with the recent price rally, prices are much lower (and interest rates higher) than in the previous growth spurt. Furthermore, given the higher current baseline of shale production, along with its steep decline rates, even more wells will need to be brought on-line in the future in order to create the same effect on production (as shale becomes a larger percentage of total production, the average decline rate will increase, requiring additional drilling just to maintain the current level of production). This is known as the “Red Queen” effect: you must continually run faster just to stay in the same place. The next chart details how US production is increasingly dependent on shale production.




Other factors are at play as well. For example, most shale oil operators focused on their very best areas (or "sweet spots") during the downturn. These areas provided the most oil for the least expenditure, thereby maximizing income during the extremely challenging price environment. There is significant uncertainty around how long these "sweet spots" will last. They certainly will not last for forever. In addition, operators have made technological advances (longer horizontal well lengths, more fracturing stages, more sand injected per lateral foot, etc.) and these advances have paid off in greater production per well. However, they each come with a cost (longer well laterals result in fewer wells per section, more sand injected increases well cost, etc.).

During the recent downturn there have been many reports of the new low "break-even" prices for shale production. But, "break-even" can mean many different things as the chart below illustrates. Breaking even on an operating basis is much different than making money over the entire life cycle of a well. In addition, each company has a different set of reservoir assets with a different cost and expense structure. "Full" cycle break-even is most effectively shown as earnings per share (over a several year period). It is clear that, while some shale producers are making money, none are raking it in hand over fist – even after the recent price rally.

<table>
<tr><td rowspan="16">Full Life Cycle Cost</td><td rowspan="6"></td><td rowspan="3">Finding Costs</td><td>Reservoir Delineation</td><td>Full-Cycle "Break-Even"</td></tr>
<tr><td>Leasing</td><td></td></tr>
<tr><td>Exploration</td><td></td></tr>
<tr><td rowspan="7">"Development" Costs</td><td>Decomiisioning</td><td></td></tr>
<tr><td>Gathering infrastructure</td><td></td></tr>
<tr><td>Financing Field development</td><td></td></tr>
<tr><td rowspan="10">"Half-Cycle" Costs</td><td>Financing well development</td><td>Half-Cycle "Break-Even"</td></tr>
<tr><td>Well Pad & access Road Construction</td><td></td></tr>
<tr><td>Well Construction and Fracturing</td><td></td></tr>
<tr><td>Engineering</td><td>Operating "Break-Even"</td></tr>
<tr><td rowspan="6">Production Cost<br>Operating Expense<br>"Lifting Cost"</td><td>General & Administrative</td><td></td></tr>
<tr><td>Wastewater Disposal</td><td></td></tr>
<tr><td>Transportation</td><td></td></tr>
<tr><td>Royalties</td><td></td></tr>
<tr><td>Taxes</td><td></td></tr>
<tr><td>Lease Operating Expenses</td><td></td></tr>
</table>

One thing is abundantly clear for oil operations: revenues and expenses change, sometimes significantly, over time. As a result, the "break-even" price (by any definition) is a moving target. There is no doubt (in our minds at least) that US production will increase. However, we have significant doubts that US production will be so overwhelmingly strong as to cause prices to remain in the 50-ish $/bbl (or even $65ish) for any extended period of time. At current prices, the cost of expanding production is too great to allow US shale alone to meet the world's future demand-supply gap. Stores are likely to continue to fall. US shale production is likely to increase, but not enough to meet demand all on its own. Prices will likely rise (as it did from 2004-2008) without OPEC meaningfully increasing production. Other expensive sources of production will eventually get invested in, but they will take time to come on-line. Price will likely rise to the point of demand-destruction, once again.

Human creativity and ingenuity has not ended. Will technological advances happen so quickly that prices do not rise significantly in the future? If history is a guide, low prices incentivize ingenuity for the sake of survival (find a way to do more with less) and spur demand, which eventually leads to reduced supply and high prices. High prices, in turn, incentivize ingenuity for the sake of profit (find a way to produce more to sell more) and destroy demand, which eventually leads to low prices. Nothing in the recent past provides any indication that this cycle is broken. It may be bumpy, but not broken. Each oil cycle is different, unique to its own circumstances, but cyclical nonetheless.

We are not in the business of predicting the future. We have no idea what the price of oil might do in the short term. In the long-term, however, both the market fundamentals and the historical context point to increased prices in the future. At some point, it might actually be "different this time." EVs (or some other technological advance) are likely to dominate the market eventually, but that time has not yet come – and does not appear to be likely in the next 3-5 years. During that time, it is very likely that demand for oil will remain strong and higher prices will be required in order for supply to meet demand.

Our purpose is not to predict the price of oil, but to better understand the market and where we are in the business cycle – so that we can better evaluate the value of potential businesses.

**For Further Reading:**

IEA Oil Market Report
https://www.iea.org/oilmarketreport/omrpublic/

OPEC Monthly Oil Market Report
http://www.opec.org/opec_web/en/publications/338.htm

EIA
https://www.eia.gov/petroleum/data.php
http://ir.eia.gov/wpsr/overview.pdf

International Monetary Fund
http://www.imf.org/en/Data

Technical Options for Processing Additional Light Tight Oil Volumes within the United States
https://www.eia.gov/analysis/studies/petroleum/lto/pdf/lightightoil.pdf

Hydraulic fracturing accounts for about half of current U.S. crude oil production
https://www.eia.gov/todayinenergy/detail.php?id=25372#

Federal Reserve Bank of San Francisco Economic Letter: Forecasting Chinas Role in World Oil Demand
https://www.frbsf.org/economic-research/publications/economic-letter/2017/august/forecasting-chinas-role-in-world-oil-demand/

MIT Center for Energy and Environmental Policy Research: Tight Oil Development Economics
http://ceepr.mit.edu/files/papers/2016-012.pdf

Lower Oil Prices and the U.S. Economy: Is This Time Different?
https://www.brookings.edu/wp-content/uploads/2017/02/baumeistertextfall16bpea.pdf

Federal Reserve Economic Data (FRED)
https://fred.stlouisfed.org/series/M12MTVUSM227NFWA/

IMF Working Paper: Oil Prices and the Global Economy
https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=6&cad=rja&uact=8&ved=0ahUKEwj9-MS8st3YAhVRXKwKHW0tBkUQFghHMAU&url=https%3A%2F%2Fwww.imf.org%2F~%2Fmedia%2FFiles%2FPublications%2FWP%2Fwp1715.ashx&usg=AOvVaw2jYMG45Cf09DIvDozhybqF

Lifting the U.S. Crude Oil Export Ban: Prospects for Increasing Market Efficiency
https://www.kansascityfed.org/publications/research/er/articles/2017/2q17cakirmelek-ojeda-fomc-lifting-crude-oil-export-ban

Causes and consequences of the oil shock of 2007-2008
http://www.nber.org/papers/w15002

Wheat Studies
https://ageconsearch.umn.edu/record/142876/files/wheat-1933-03-09-06.pdf