



## Crude Oil: Five Year Outlook

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UWA Student Managed Investment Fund  
ECONOMICS TEAM

## The Oil Capex Cycle

On August 28, 1859, George Bissell and Edwin L. Drake made the first successful use of a drilling rig on a well to produce oil, at a site on Oil Creek in Pennsylvania. The kerosene lamp ultimately created the first large-scale demand for oil in the early 1860s. Since then, the oil industry has become a one thousand and seven hundred billion dollar industry dominating much of developed nations' GDP. The oil price refers to the spot price of a barrel of crude oil, which is an unrefined petroleum product used to produce usable products such as gasoline diesel and other forms of petrochemicals. When analysing the price of oil it is important to note we are using the WTI benchmark price which is the most widely accepted measurement for oil used by the New York Mercantile Exchange (NYMEX). The price of oil is determined largely by demand and supply and its price cycle can be distinguished into 5 distinct stages as explained below.

1. In the first phase, a pickup in commodity-intensive growth such as a mining boom causes a global surge in demand for commodities which outstrips supply. As demand pushes up against capacity limits, prices rise.
2. In the second phase, high prices caused by the supply and demand imbalance induce large amounts of capital expenditure to bolster oil reserves. As prices rise, margins for commodity producers increase and profits rise. These producers, experiencing high profit margins invest in profitable opportunities to expand production. There is an enormous bout of capital expenditure which causes an investment boom in the oil industry. This only perpetuates growing levels of demand in the economy and begins to create bottlenecks in many labour markets. As it reaches full capacity, inflation begins to escalate.
3. The third phase is typically marked by a slowdown in commodity demand that occurs when the original growth that sparked the cycle begins to fade and high prices begin to reduce demand through substitution effects. Simultaneously, the initial investment finally begins production which increases the supply in the market. This phase is dubbed the 'turning point' in the price cycle with high prices setting in motion increases in supply and reduction in demand.
4. In the fourth phase, there is an oversupply of oil in the market known as an 'oil glut'. The initial capital expenditure has created excess supply which is now being held in expensive oil inventory tanks. The increase in oil inventories puts greater downward pressure on oil prices as producers attempt to reduce expensive oil storage costs by decreasing oil inventory levels.
5. As prices for oil fall, margins for commodity producers are squeezed. In this phase, producers respond to low prices by slashing investment and in some cases shutting down production permanently. Only the large companies who have achieved economies of scale survive while smaller companies leave the market. This decline in supply eventually brings the market back into balance, as the low investment deteriorates capacity,

From an analysis of the current oil price (\$75 USD), the global economy can be seen as being in the last part of the first stage of the oil cycle. This stage is characterised by a reduction the supply glut and improvements in price levels as they move back into equilibrium. The improvements in crude oil prices represent the oil price rebalancing from a 3 year low in 2016. This reduction in supply is largely being driven by the Organization of the Petroleum Exporting Countries (OPEC), with members and other major producers including Russia agreeing to continue production curbs, beginning in January 2016. If history is anything to go by the oil price still has a way to go before it reaches a turning point in stage three of the oil cycle.

## Case Study 2000-2016

As the old adage goes, hindsight is always 20/20. Looking back at the booms and busts of the last decade in the context of a commodity super cycle, it's hard to imagine the fluctuations in oil prices as being anything other than predictable. The cyclical variation in oil prices is firmly embedded in the industry's

structure and can always be understood in terms of the surrounding macroeconomic events. As a general overview, oil prices rose gradually from 2004-2008, plummeted with the Global Financial Crisis (GFC) in 2008-09 and resurfaced in a dramatic price hike in 2010, only to fall again in 2014. A true, and certainly inevitable, rollercoaster ride with considerable economic implications.

From the period 2004-2008, the market forces of supply and demand drove the spot price of crude oil steadily upwards. In particular, the major players driving growth in positive aggregate demand were China and India. China recorded an average GDP growth of 12.11% per annum over 2004-2007, with India trending slightly lower at average GDP growth 9.07% over the same span. Namely, both countries faced strong income growth, exponential increases in population, and an increasing trend towards energy-intensive economic activity, which in China's case is heavily subsidised by government. In a recent report, it was estimated that subsidies for China's fossil fuel industry totalled US\$15.42bn, with the majority directed at lowering petrol prices to the benefit of household consumers. As emerging economies move progressively from a developing to developed status, greater demand is placed on oil consumption predominantly for motorised transportation and industrialisation needs.

However, this increase in demand for oil was not matched by a successive increase in supply, owing in part to the slow responsiveness of production. Two large negative supply shocks contributed to the reduction in supply and the consequent bottleneck in global oil prices, reaching a peak of \$147 per barrel in 2008. With Hurricanes Katrina and Rita blowing through the Gulf of Mexico in 2005, production fell by an average of 1.57 million barrels per day in the month following and severely restricted production capacity. The ongoing impact of the Venezuelan Crisis and conflict in Iraq curbed production capacity in OPEC countries. Lastly, global reliance on Saudi Arabia's oil reserves led to general expectations they would use their excess capacity to compensate for the shortfall in supply. Instead, production levels fell, though it is uncertain whether this was a deliberate policy response to take advantage of rising crude oil prices.

The GFC hit the oil industry from all sides. The panic initiated by defaults in the sub-prime housing market resulted in large-scale deleveraging by financial institutions and led to a rapid collapse in oil prices. This sudden fall in demand for oil by OECD countries was met in equal measure by the drying up of available credit. Investments that would have taken place in exploration or development of oil reserves were deferred in the face of economic uncertainty, manifesting itself as a retraction in supply with long-term consequences for global reserves. The OPEC met four times to prevent further declines in the prices of oil by restricting production and stalling the rise in inventories.

May 2009 marked the pick-up of global oil prices, in line with consumer sentiment, perhaps signalling the worst of the GFC had passed. From this point on, the global economy witnessed the steady recovery of prices in response to constrained global supply and limitations on spare capacity. Growing civil unrest in Libya combined with the violence of the Arab Spring, a series of armed rebellions in protest of Arab dictatorships, saw the closure of a number of oil production facilities in Libya. The significance of the Middle East and North Africa in producing more than one-third of the world's oil, was felt with the loss of 1.5 million barrels per day in exports from Libya. Supply was further constricted in 2012, with Iran defying UN sanctions on its nuclear activity and threatening to cut exports passing through the Strait of Hormuz. The Strait of Hormuz is a critical passage through which crude oil from Saudi Arabia, Iran, the United Arab Emirates, Kuwait and Iraq must travel. However, this supply shock was somewhat mitigated by a pledge from Saudi Arabia to compensate for any shortfall from Libya.

The transition in mid-year 2014 to falling oil prices was driven primarily by abundant supply, dwindling demand from economies including China, India and Russia, and the makings of the US shale oil boom. Higher prices of the previous decade saw the advent of fracking procedures in North Dakota by US companies and in Alberta oil sands in Canada in a bid to combat increased production costs. Consequently, both major OECD countries cut oil imports significantly. The immediate response of Saudi Arabia to prevent a loss of market share was to slash prices on oil exports to America. The slightly costlier hydraulic

fracking procedures in the US require oil prices within the \$70-\$100/bbl range to remain profitable; a limitation Saudi Arabian producers were banking on. With the intention of outlasting US and Canadian shale oil producers at levels of reduced profitability, Saudi Arabia's strategy in combination with strong US and Russian oil production saw the Brent crude oil price slip to \$62/bbl and similarly with WTI crude oil at \$59/bbl in December. A particularly momentous political decision saw the 40-year ban on US oil exports lifted at the end of 2015. Ideally, this would have seen oil producers expanding their international supply chains after decades of restriction to lower prices of local refineries. However, the time-lag associated with legislative proceedings saw global oil prices slump, providing no initial incentives for US oil exports. From there, global oversupply carried low oil prices into the rest of 2016 until OPEC countries met to cut oil production. Thus, in the face of weak global demand and efficiency gains in US shale production, the plunge in oil prices from 2014-16 failed to significantly boost global economic growth.



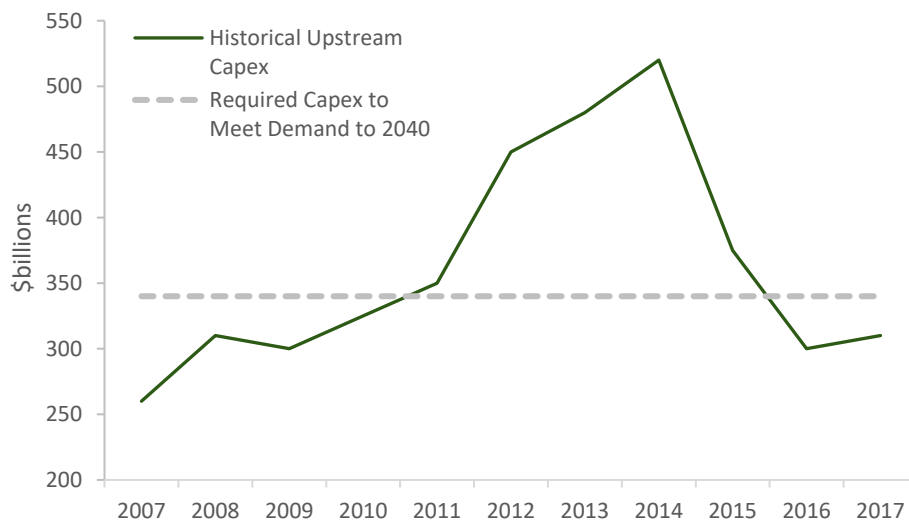
## Outlook for the Next Five Years: Summary

Over the next five years, there will most likely be a shortage of crude oil worldwide off the back of the collapse in upstream investment which was experienced after crude prices fell significantly. While OECD oil consumption is expected to stagnate and decline slightly by 0.6 million barrels per day (mb/d), virtually all growth in oil demand will come from non-OECD nations. Non-OECD nations are expected to consume an additional 7.5 mb/d as their economies rapidly grow. OPEC's future as an oil cartel is in jeopardy over the next five years as they lose market share to upcoming non-OPEC producers. OPEC is expected to expand production slightly by 0.5 mb/d as gains in the non-Saudi Middle East offset losses in Africa, and South America. The United States will be the largest contributor to supply growth, adding an additional

3.7 mb/d if all goes to plan, while Brazil, Canada, Norway and Russia add an additional 0.75 mb/d, 0.5 mb/d, 0.3 mb/d and 0.8 mb/d respectively. In aggregate global supply growth of 6.5 mb/d falls short of global demand growth of 6.9 mb/d leaving a shortage of crude of approximately 0.4 mb/d by 2023.

## Upstream Investment

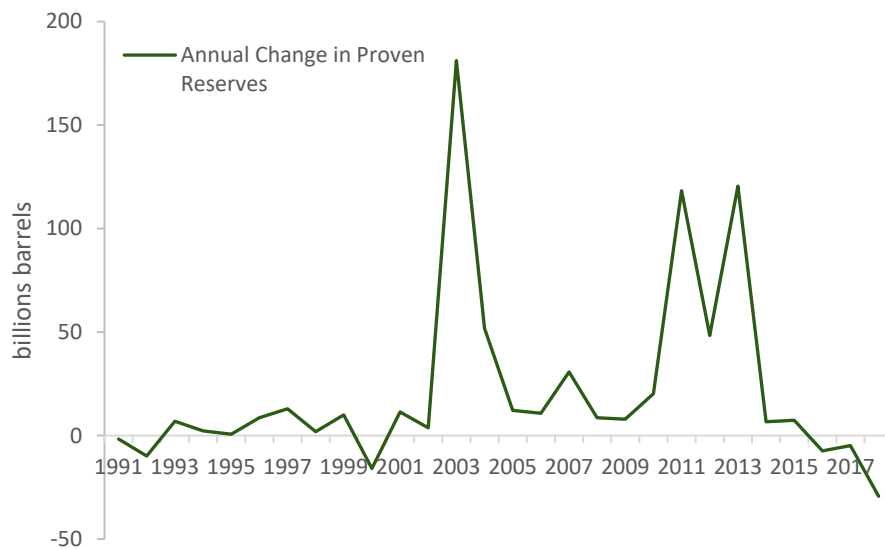
During the last oil bear market from 2014-2016 as oil fell from over \$100 barrel to below \$30 a barrel, global upstream capex in oil plunged by 25% in both 2015 and 2016. During 2017, investment levels were flat and have also only slightly risen so far in 2018 if first quarter results are annualised. The cut and lack of recovery in upstream investment poses the market for undersupply similar to the 1968-1982 and 1999-2014 periods as global suppliers struggle to offset natural field declines and meet rising demand growth. Currently the world needs to replace around 3 mb/d due to declines, which is the equivalent of replacing one North Sea per year. According to OPEC, the global oil industry needs to invest an approximately \$340 billion per year in upstream capex to meet supply needs to 2040. The world continues to underinvest throughout 2016, 2017 and most likely 2018 too.



Source: Rystad Energy, OPEC

The world continues to use more oil than it finds, as new discoveries of proven oil reserves hit an all-time low during 2017 according to the IEA at 4 billion barrels, or the equivalent of 9 days' worth of global oil consumption. IEA reported that spending on exploration and development remains at a fraction of its pre-2014 level, brewing up trouble for the future. Global proven reserves have been falling since 2015, from 1.615 trillion barrels of oil to 1.616 trillion barrels in 2017.

OPEC expects their upstream capex plans to continue declining into the foreseeable future. Expecting capex to fall from \$40 billion in 2017 to \$35 billion in 2018, this trend is expected to continue until 2021 to \$10 billion. According to OPEC, upstream activity continues to plunge with wells completed globally falling 44% from their 2013 high to 58,294, and active rigs falling 28% from 2014 to 3,807. According to the EIA, spare capacity, which is defined by the volume of oil that can be brought online within 30 days that can be sustained for at least 90 days, is approaching early 2000s lows at 1.3 mb/d in August 2018.



Source: EIA

## Supply: OPEC

### Saudi Arabia

The Kingdom of Saudi Arabia is a giant in the global oil market, often referred to as the world's 'swing producer' being able to single headedly influence oil prices at their discretion. In the past, and to some extent today, countries fear being held hostage to high oil prices by the Kingdom and their OPEC allies.

The Saudis reportedly have 266 billion barrels of proven oil crude reserves, the second largest in the world after Venezuela. The Kingdom's proven reserves haven't changed since 1998 but Saudi Arabia hasn't found any major new oil discoveries since the 1970s. As a result there is widespread scepticism regarding the true figure of Saudi Arabia's reserves.

The Kingdom's reserves have remained constant for the better part of 20 years despite consuming and exporting 94 billion barrels of oil. Assuming this data is correct, the Saudis have fortunately been able to replace each barrel of produced oil by new discoveries or recalculating recoverable oil from existing fields. However the discovery of the country's major oil fields were between the 1930s and 1970s. Conveniently, field production profiles and proven reserve estimates aren't accessible for external audits and are state secrets. Before the Saudi Arabian government took full control of the country's oil company (Saudi Aramco), it was owned jointly by four US oil companies who provided a public testimony regarding the nation's proven reserves to the US Senate's Subcommittee on International Economic Policy. In 1979, Aramco estimated proven reserves at 110 billion barrels and probable and possible reserves at 178 and 248 billion barrels respectively.

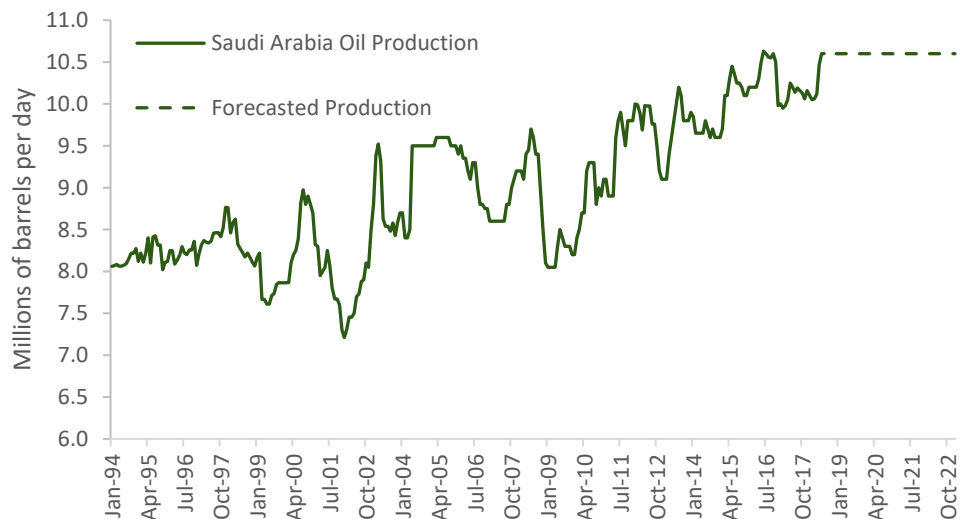
Since 1980, the Saudi government has had full control over Saudi Aramco and began reporting to OPEC with proven reserves of 170 billion barrels, a lot higher than the 110 billion reported by partners to the US Senate a few years back, but close to the 178 billion of reported probable reserves. Then in 1989 Saudi Arabia's reported proven reserves jumped to 260 billion barrels despite no new major discoveries of oil. However, this number is close to the 248 billion barrels of possible reserves reported in 1979 to the US Senate, which has led to scepticism that the Saudis have been inflating their reserve numbers. While producing more oil than initial reserve estimates due to higher understanding of the reservoir and new technology creating more oil recoverable is common, Saudi Arabia has unusually been reliant on this for reserve growth since the late 1980s.

The Kingdom currently produces around 10.6 mb/d and is reported to have around 2mb/d of spare capacity, which again is highly debated. Saudi Energy Minister, al-Falih stated in June that “It costs us between capital and opex tens of billions of dollars to keep 2 mb/d of spare capacity and we weigh very carefully whether it needs to increase or not”.

Gary Ross, head of global oil analytics at S&P Global argues that Saudi Arabia can barely increase production by 1mb/d in the short term, and that it would take time, possibly a year to bring an additional 2mb/d online. He believes that Saudi Arabia producing 11 mb/d would be running their system on stress levels and that to increase exports they would have to dig into inventories.

Over the long term, it’s also unclear whether the Kingdom can meaningfully increase production. A case has been made that Aramco has hit a production ceiling, as production on several main oil fields such as Ghawar has been running into issues. These include normal upstream problems such as black powder, corrosion, biological fouling and the misuse of seawater injections for decades now. Major pipelines have been seen blocked by corrosion and scaling, while other production has been hit by major sludging threats.

Additionally, there are other indicators that Aramco is struggling to keep existing production at their more mature fields, an estimated new 600,000-750,000 b/d of new output has to come online each year to offset depletion of existing fields. This is a major driver of the ongoing discussion within Aramco to speed up conventional field developments both on and offshore including in the Arab Gulf and the Red Sea. The development and drilling costs of these projects are much higher than conventional onshore sites, however the push is to maintain current production levels while still holding onto 2mb/d of spare capacity. According to BCA Research, the need for these projects would be much less than current investment shows. Active rigs are at lowest point since 2011 at 111, completed wells are 600 lowest level since 2015.



Source: EIA, SMIF Estimates

## Iran

Iran is the third biggest supplier of oil in OPEC. It has proven oil reserves of 157 billion barrels which has slowly depleted from 157.8 billion barrels in 2015. Iran has plans on increasing capacity by 700,000 b/d in the next three to four years to 4.7 mb/d. The nation says it might be able to increase capacity by 1 mb/d if it can reach deals on four of its oil fields with foreign companies, which at this point looks unlikely given the current political environment and sanctions which come in on full effect November 4.

President Trump took historic action to withdraw the United States from the JCPOA, the nuclear deal that was signed in 2015. The rial is tanking, unemployment in Iran is on the rise and there are widespread protests. The losses in oil exports could range from 1 mb/d to 2-2.5 mb/d if all countries comply. Despite political rhetoric by China and Europe to continue supporting Iran, private companies are cutting back on Iranian oil. European refiners have moved to sharply cut Iranian crude. China, India and Japan have all responded by dropping their Iranian oil imports in August by as much as 300,000 b/d, 400,000 b/d and 60,000 b/d respectively. India recently stated that they will be cutting their Iranian crude imports to zero by the November deadline.

Iran has threatened to take control of the Strait of Hormuz in retaliation to upcoming US sanctions. The Strait of Hormuz is a strip of water between Iran and the Arabia gulf where 30% of the world's oil supply transports through, which could potentially create disastrous effects to oil supply chains.

That being said, Iran is attempting to minimise the impact of US sanctions by measures such as secret oil shipments without trackers on tankers, bartered trades, discounts and commodity swaps. According to Bloomberg, Iran used secret shipments to export millions of barrels of oil during the last round of sanctions, or approximately 200,000 b/d being undisclosed. However it's reasonable to assume that the Trump administration will be a lot tougher on sanction than the previous administration.

Last time Iran was sanctioned about half of its oil exports ~2.4 mb/d were removed from market. The success of the sanctions is largely contingent on its major buyers in Asia receiving sanction waivers, it's also questionable whether China, Iran's biggest purchaser, will comply.

## **Iraq**

Iraq may be one of the only countries within OPEC that can meaningfully raise production over the next five years. Currently Iraq pumps 4.6 mb/d falling short of their claimed production capacity of 5 mb/d. The nation intends on raising production capacity to 6.5 mb/d by 2022. Iraq is also unique within OPEC, finding major discoveries growing their proven reserves from 115 billion barrels in 2011 to 148.7 billion barrels today. While Iraq has the fourth largest amount of proven reserves in the world, Oil Minister Jabar al-Luaibi said that actual reserves may be twice as large. If proven correct, it would make Iraq the most oil rich country the world, ahead of both Venezuela and Saudi Arabia with 300 billion and 260 billion barrels respectively.

While Iraq's oil future looks bright, there are some who aren't as optimistic. IHS Markit analyst Christopher Elsner argues that Iraq's capacity is around 7 mb/d however believes Iraq will only be able to produce 5 mb/d over the next decade and 6 mb/d by 2036. He states that the country's political and economic circumstances will drag on its ability to grow production significantly. Iraq is currently dealing with protests in the south motivated by issues ranging from access to drinking water to electricity and high unemployment. There are also oil industry specific issues, the connections between the oil fields and the storage farms in the south and the export points have been creating bottlenecks in Iraq.

Pipeline shortages and electricity shortages are among challenges that Iraq has to deal with in order to improve production capacity. The state run company responsible for oil projects in mid-stream has a spotty execution track record, there is legal uncertainty around contracts, security risks and unreliable water and electricity. Therefore Iraq will most likely be able to increase production by around 0.5 mb/d over the next five years.

## **Kuwait**

Kuwait has 101.5 billion barrels of proven oil reserves, and haven't found any major oil discoveries since 2005. Kuwait currently pumps 2.7 mb/d below its high of 3 mb/d during 2012. Since then upstream activity has dwindled, with 555 completed wells, the lowest since 2012 and producing wells has fallen to 1689, the lowest since 2011.

Kuwait claim a production capacity of 3.150 mb/d and is aiming to increase capacity to 4.75 mb/d by 2040. Over the short term, Kuwait have stated that they can produce 3.25 mb/d by March 2019 if the November 2016 OPEC+ agreement is winded down.

## **UAE**

The United Arab Emirates (UAE) produces 4.5% of the world's crude oil, and reportedly has 97.8 billion barrels of proven reserves, a figure that hasn't changed since 1999. Abu Dhabi has most of the country's reserves with 92 billion barrels, Dubai sitting on 4 billion barrels and the remaining at Sharjah. Most of the oil is located in the Zakum field which is the third largest in the Middle East with an estimated 66 billion barrels.

Abu Dhabi National Oil Company states that they can raise production by hundreds of thousands of barrels in the short term to meet supply shortfalls in needed. The company believes UAE's production capacity to be 3.3 mb/d and intends on reaching 3.5 mb/d by the end of 2018. Without any major new reserve findings, and a questionable reported reserve figure, it's unlikely the UAE will be able to meaningfully increase production over the next five years.

## **Angola**

Angola's oil industry has been suffering from decline since 2010, when the country was producing nearly 2 mb/d, now pumping 1.5 mb/d. Angolan President, Joao Lourenco has been trying to incentivise oil investment in the nation by halving tax rates on development of oil reserves less than 300 million barrels. The country's proven reserves are reportedly 9.5 billion barrels which have decreased from 10.5 billion barrels in 2013.

Angola's oil fields are maturing and are near depletion, active rigs have collapsed from 30 in 2015 to 7 in 2017 and completed wells have more than halved since 2013 to 43. Unless new investments are made soon, Angola's oil capacity will drop to 1.3 mb/d over the next five years according to the IEA, in contrast to its OPEC quota of 1.7 mb/d.

Three oil majors have invested in Angola in recent years, including Chevron, Eni and Total. Their discoveries have added to Angola's crude production and exports haven't be large enough to compensate depletion of maturing fields.

## **Libya**

Libya has the largest proven oil reserves in Africa at 48 billion barrels which has climbed from 41 billion barrels since 2007. During the 1970s under the rule of Muammar Gaddafi, the nation was producing over 3 mb/d. However, due to depletion of reserves and the overthrow of Gaddafi, by 2011 the country's production fell to 1.6 mb/d and now they are struggling to produce 1 mb/d.

According to Libya's state-owned National Oil Corporation (NOC), the country could produce 2.2 mb/d by 2023, but needs \$18 billion of investment to reach that production level. However, due to Libya's political instability it's unlikely any foreign investment is coming any time soon.

The overthrow of Gaddafi in 2011 has left a power vacuum in the country mainly between the east and west. Local groups have used oil facilities as bargaining chips to press financial and political demands, being fought over by various parties resulting in prolonged shutdowns. As Libya's oil revenue plummets, demands for salaries, local developments and jobs have feed into protests and blockades.

Islamic State militants attacked oilfields in 2015-2016 and their destruction of local infrastructure, including of storage tanks at Libya's two biggest terminals (Es Sider and Ras Lanuf) has yet to be repaired.

Political risks loom in the future, with factions in the east opposed to the current international recognised government. This is troublesome as this is where most of the country's oil deposits are located. They argue that the government hasn't distributed sufficient oil income to eastern regions, leading some groups to threaten to cut off oil production. However currently the Libyan National Army (LNA), which has good relations with the government in Tripoli, has been able to keep fields and ports open.

Security is still volatile in the country for oil producers. Last December an explosion on a pipeline in Eastern Libya caused a loss of 100,000 b/d, while international companies are operating offshore, and they have a limited presence onshore keeping exploration and development on hold due to political instability.

## **Venezuela**

Venezuela reportedly has the largest amount of proven reserves in the world at 302.8 billion barrels, constituting around 20% of total proven oil reserves in the world. Analysts are sceptical of these figures as a large proportion of Venezuelan reserves are expense to extract oil sands which may not be economical and therefore 'proven' at all.

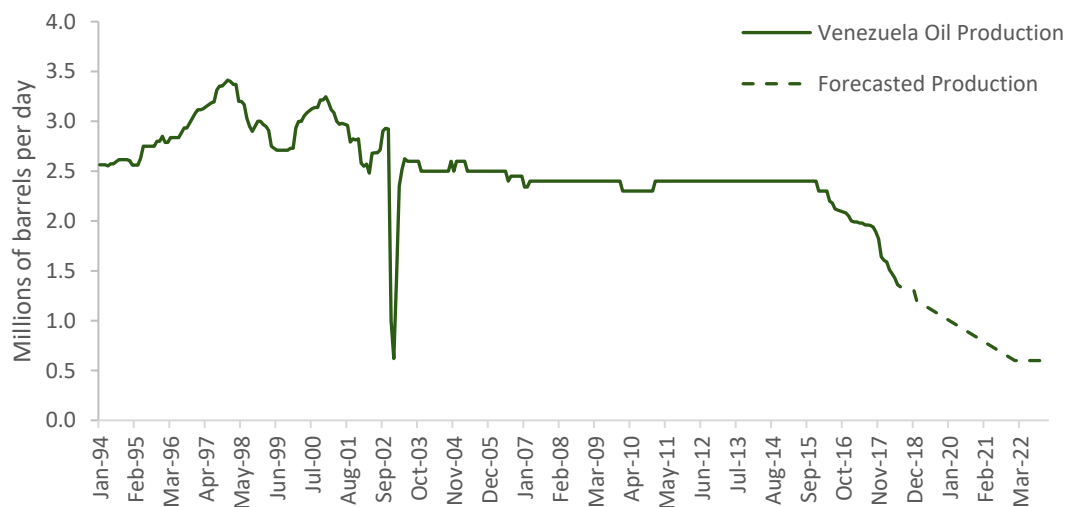
After the oil collapse in 2014, Venezuela whom relied on oil for 95% of its hard currency, found themselves in need of widespread sacrifices in order to pay for imports. Discontent with the government grew, responding with political repression to retain control. Venezuela has been experiencing an economic collapse and hyperinflation is forecasted to reach 1 million percent by the end of 2018, according to the IMF. In August, President Maduro devalued the Venezuelan Bolivar by 95% and many hundreds of thousands of citizens have fled to nearby countries to escape severe food and medicine shortages, violent crackdowns and unemployment.

The nation's previous President, Hugo Chavez deprived Venezuela's oil industry of reinvestment to fund socialist programs, now it has came back to bite Venezuela's production capacity. Insufficient investment as well as working capital and famished workers have become too weak for intensive labour. The US and European Union has imposed sanctions on the country for human-rights abuses and political repression.

Venezuela currently pumps 1.3 mb/d and production has slowly collapsed, this year alone falling by 300,000 b/d and by 700,000 b/d since the beginning of 2017. Completed wells have fallen from 1050 in 2011 to 478 in 2017 and producing wells have reduced from 14,915 in 2011 to 11,915 in 2017.

In September 2018, Venezuela agreed to hand over at least seven oil fields to small companies that will be compensated on the basis of increasing oil output. The issue is that these companies have no known experience operating oil fields and US and EU sanctions will most likely impede more experienced operators doing business with state run PDVSA. The contract viewed by Reuters offers the seven companies ownership of the fields for six years conditional on the companies shoring up required financing and equipment. According to Reuters the seven companies haven't confirmed plans with Venezuela. The President of the PDVSA announced that the plan would require \$430 million dollars of investment but

would increase production by 641,000 b/d. The companies would receive a fee for additional barrels produced and would be compensated for the initial capex. While this deal enables higher production, nothing has been confirmed and requires a significant amount of risk as stated above. As Venezuela's economy collapses it's reasonable to assume so too does its oil production.



Source: IEA, SMIF Estimates

## Supply: Non-OPEC

### Russia

Russia is currently the world's largest crude oil producer, pumping 11.2 mb/d, a post-Soviet high. The Russians have 80 billion barrels in proven reserves which jumped from 60 billion in 2012. Under the OPEC+ agreement in November 2016, Russia agreed to cut 300,000 b/d in efforts by OPEC and Non-OPEC members (mainly Russia) to rebalance the global oil market to diminish the glut which had caused crude to collapse from over \$100 a barrel to below \$30.

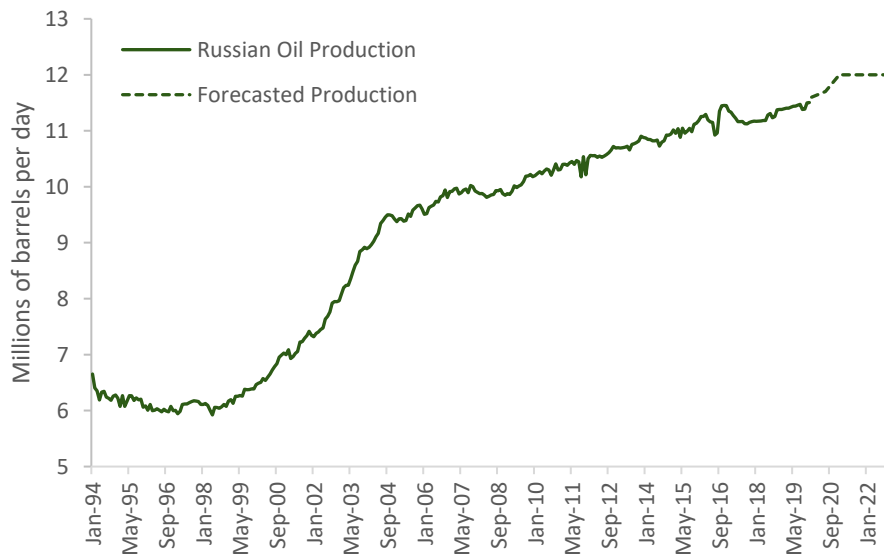
In June, OPEC+ agreed to increase output by 1 mb/d to help offset supply reductions from Iran, Venezuela and Libya, of which Russia was one of the main beneficiaries agreeing to increase production by 200,000 b/d nearly offsetting all their production cuts from two years ago. Now the question remains, how much spare capacity does the Russian Federation have to supply world markets going forward?

This is a topic of wide debate, given Russia's important position in the oil market. Alexander Novak, Russia's Minister of Energy recently stated in an interview with Bloomberg that Russia could bring on an additional couple of hundred of thousand barrels per day in the short term. BofA Merrill Lynch estimate that Russia will retain 360,000 b/d in swing capacity by the end of 2018 and accumulate an additional 140,000 b/d in spare capacity by the end of 2019, bringing their total spare capacity at around 500,000 b/d. Renaissance Capital believes that holds around 215,000 b/d of idle production that can be brought online.

Russia has deemed to be proactive. Anticipating the end of the production cuts, oil companies have continued to prepare major greenfield projects in preparation for full scale development, building up spare capacity, according to Novak. However, it is unclear whether Russian oil companies have been conducting investment to expand production, or simply offset decline rates.

Several new greenfield projects such as Messoyakha, Suzunskoye and Trebs & Titov fields as well as continued capex into brownfield have also been implemented to offset natural decline in the country's mature base. This is needed as the abundance of reserves in their Arctic and non-conventionals remain uneconomical. Intensive drilling in recent years has reportedly helped just to maintain production at some of the mature fields such as Rosneft's Yuganskneftegaz according to Citi Research.

The Russian government is conservative in their guidance, suggesting that Russian crude production won't grow but will be maintained at current levels of 11.2 mb/d till 2020-21 then slowly decline by 100,000 b/d by 2024. Citi is a lot more optimistic however, stating that Russia can pump 12 mb/d by the end 2020 due to these new large greenfield projects.



Source: IEA, SMIF Estimates

## USA

The United States has played an important role in the oil market in the past decade. The recent technological advancement of hydraulic fracturing, known as 'fracking' enabled the rise of shale oil. The United States' proven oil reserves were slowly depleting from 1970 from roughly 40 billion barrels to 20.5 billion barrels in 2009. However technological advancements in hydraulic fracturing enabled producers to tap into oil in shale rock formations which set off an unprecedented growth in crude production. Shale oil output grew from 450,000 b/d in 2008 to over 5 mb/d currently which now accounts for over half of USA's total oil production. Proven reserves rose by 75% from their 2009 low to 35 billion barrels in 2017 as a result.

The sudden growth in supply from shale oil in the U.S. contributed to the beginning of the last oil bear market from 2014-2016, leading the world from a shortage of -0.8 mb/d to a surplus of 0.6 mb/d in 2014. Shale oil wells, or unconventional wells are much more responsive to changes in oil prices or expected future oil prices. This is mainly due to the fact that the extraction process for unconventional wells, which involves stimulating the wells with water, sand and chemicals, can be done numerous times throughout the life of the well, unlike conventional wells.

This reversibility of extracting shale oil wells could arguably place the United States as the world's true 'swing producer' - removing large swings in the oil price as production closely follows prices. In fact, the United States is on its way to becoming the world largest producer of crude oil, pumping on average for the first three weeks of September 11 mb/d according to the EIA, closely lagging the Russian Federation

at 11.2 mb/d. Following the explosion of new proven oil reserves in the United States, the shale oil boom has justified some very rosy forecasts for the future of crude production coming out of the U.S.

The EIA expects another 700,000 b/d growth in oil production by the end of 2019 to reach 11.7 mb/d. Specific areas for shale oil growth are the Bakken Basin in North Dakota and the Permian Basin in Texas. Currently, the Permian is the largest shale oil producing region. If it lives up to expectations it will account for more than 50% of growth in crude oil production in 2019 according to EIA estimates, with IHS Markit analysts placing it at 60%. In the Permian basin alone, the EIA predicts growth from 3.3 million b/d in 2018 to 3.9 million b/d in 2019. However, even with nearly 41,000 new wells and \$308 billion in upstream spending during the period 2018-23, the actual output will be determined by pipeline capacity and supply chain bottlenecks. In particular, pumping capacity is highly restricted due to record levels of drilling activity, with the market for frac sand, a critical component in shale oil extraction, extremely tight. This has flow on repercussions in the wear and tear of road tarmac and demand for trucks to transport shale oil. This is further exacerbated with pipelines trending at full capacity, 3.078 mb/d.

The Bakken Shale Play is the next biggest oil producer in the US with production levels of 1.2 million bpd in April earlier this year. Despite the maturity of its wells and a reduction in Tier 1 geologic quality drilling locations, word on the street amongst shale CEO's remains optimistic as long as oil prices stay above \$60/bbl. Further, the Bakken's 60 active drilling rigs are much more sensitive to fluctuations in price. It has the narrowest breakeven price range of the three major oil plays at \$40-\$60/bbl. This is in contrast to the Permian Basin which boasts a significantly lower average breakeven price of \$47/bbl over a range of estimates from \$20-\$70/bbl.

Taking a more long term perspective, the International Energy Agency (IEA), estimates that the United States' growth in crude production will reach 3.8 mb/d by 2023, pumping a total of around 15 mb/d making the US the main driver surging oil production throughout the world.

The Post Carbon Institute argues that the EIA is over stating the potential of shale growth describing their forecast as 'highly to extremely optimistic'. Their report argues that shale oil possess major headwinds such as the short lived wells, shale oil wells typically deplete by 70-90% in the first three years of extraction while fields see production drops from 20-40% per year without new drilling. At the same time, not all shale wells are made equal, the 'sweet spots' usually make up 20% of a shale play, when drillers move beyond the core they tend to have less impressive production numbers. The majority of drilling that has occurred over the past decade, accompanying with exploding production growth, has occurred in these 'sweet spots'.

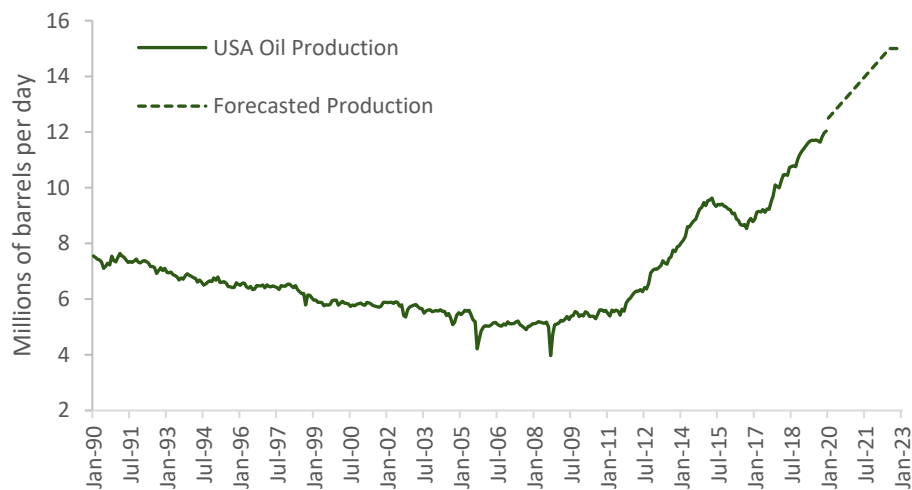
Improvements in drilling technology has more than compensated for natural depletion. Shale drillers today can access far more of a reservoir than they could a few years ago. The Post Carbon Institute says the EIA's assumption is that over the next decade all proven reserves will be produced combined with a high percentage of unproven reserves, in some cases over 100% by 2050.

The Bakken oil field for example is already shown signs of wear, "well productivity improvements have flat-lined or decreased in all by two counties, indicating available well locations are running out". The Eagle Ford field is also strained, as they argue that the EIA has overstated its potential by over 65% compared to the current prospective drilled area. The report argues that while drilling techniques may continue to improve, it just may be too expensive to produce as much crude oil as the EIA expects.

Another issue surrounding the future of shale oil growth is the capital intensity of the sector. Jim Chanos famously called shale oil, 'creatures of the capital markets' revolving through a value destroying cycle of burning cash and raising more capital. In July 2018 however, the EIA stated that shale oil producers were on their way to positive free cash flow for the first time ever by the end of the year due to higher prices and operational improvements. A month later a report from the Wall Street Journal reported that two-

thirds of U.S. oil producers stated negative free cash flow even with oil hovering at around \$70 a barrel. The report indicated that “collectively, 50 major US oil companies reported in their second-quarter results that they have spent more than \$2 billion than they took in, according to an analysis of free cash flow by FactSet.” The report also argues that efficiency gains in the industry have been largely tapped out. Costs for sand, water, drilling crews, equipment and other services are on the rise. Another threat to cost inflation lies in the future pickup in activity of drilled by uncompleted wells (DUC), where shale companies all try to get their DUCs reduced from 2019-2022.

While shale could turn the United States into a potential crude oil superpower, the future remains elusive with very optimistic forecasts, cost inflation, extremely high depletion rates and therefore potentially unsustainable capital structures.



Source: IEA, SMIF Estimates

## Nigeria

Nigeria has now fallen behind Angola to be Africa’s second largest oil producer supplying 1.48 mb/d and is sitting on top of 37.4 billion barrels of proven reserves which has slightly increased from 37.2 billion barrels in 2010. In 2016, Exxon Mobile announced a 500 million barrel deposit in the Owowo-2 and Owowo-3 oil fields.

Nigeria’s maximum capacity is 2.5 mb/d, however militant groups, such as the Niger Delta Avenger have been attacking infrastructure and producing facilities causing slowdowns in Nigeria’s oil industry. As a result, active rigs have fallen from 44 in 2012 to just 13, completed wells have fallen from 114 in 2013 to 76 and producing wells have dropped from 2168 to 1777.

Despite being oil rich, Nigeria’s political instability is impeding the country producing at their potential capacity of 2.5 mb/d, and the dangerous environment will most likely repel the required investment from foreign oil companies need to maintain or even grow production in the future.

## Norway

Norway’s proven oil reserves currently sit at 6.4 billion barrels which has increased recently from 5.4 billion in 2013. However Norway’s proven reserves have slowly declined from their peak in 1988 of 10 billion

barrels due to the slow depletion of the North Sea. Norway is the largest crude oil producer in Western Europe, pumping 1.6 mb/d albeit a lot lower than their peak oil production of 3.2 mb/d in 2000.

In 2010 a large oil field called Johan Sverdrup was discovered in the North Sea. The field has proven reserves estimated between 2.1 and 3.1 billion barrels and production is expected to come online in late 2019. The development is estimated to have a nameplate capacity of 660,000 b/d by 2022. John Castberg is Norway's largest field developed in the Barents Sea with 0.5 billion barrels of proven reserves and a nameplate capacity of 200,000 b/d by 2022.

The Norwegian Petroleum Directorate (NPD) expects that Johan Sverdrup and John Castberg will account for nearly half of Norway's oil production, as they believe these major developments will slightly offset natural decline rates in existing fields over the next five years to result in Norway pumping a total of 1.9 mb/d.

In 2017, the NPD re-calculated that the Barent Sea had double the amount of undiscovered reserves than initially thought. Norway therefore has 12.4 billion barrels of undiscovered reserves, two-thirds of which are located in the Barent Sea.

Major discoveries in the Barent have been a lot smaller than what Norway's drillers have familiar with in the North Sea consisting of billions of barrels. Major findings in the Barent, such as Johan Castberg and Goliat have turned out to have only hundreds of millions of barrels. There's also less interest from firms in the Barent Sea, in the latest shelf licensing only 11 companies applied for production licenses for 102 blocks (most of which were located in the Barent). In contrast, the last round in 2015 there were double the bids.

On average, discoveries and wells have been smaller than in the past. According to the Norwegian Petroleum Directorate, discoveries and wells drilled must be above average for the past decade if production is to be sustained.

Norway has been no exception to the dry up in upstream investment with active rigs sitting at a six-year low of 16 and exploration at its lowest level in a decade. Coupled with the depletion of the North Sea and troubles developing large discoveries in the Barent Sea limits the growth in Norway's crude production. Due to these headwinds, Norway may be able to increase supply by a couple of hundred of thousand barrels per day over the next five years.

## **Brazil**

Brazil is currently the biggest crude producer in South America pumping 3.8 mb/d with only 12.6 billion barrels of proven reserves, just a fraction of Venezuela's supposed 300 billion barrels. Brazil possess massive offshore pre-salt oil fields located in the Atlantic Ocean on their continental shelf. Estimates range on the amount of proven reserves in these fields, but the go up to 50 billion barrels.

While they have been difficult and costly to distract in the past, the National Petroleum Agency (ANP) believes that if effectively exploited, the pre salt area could double Brazil's proven reserves to around 26 billion barrels.

In 2017, offshore drilling and discoveries fell significantly associated with spending cutbacks with Petrobras while it was caught up in a corruption scandal. Petrobras was mandated as the sole operator in the pre-salt belt. High operating costs and regulations saw Brazil as unattractive location for foreign oil companies to invest, and active rigs have fallen from 86 in 2011 to just 14 in 2017.

However a combination of reforms, reduction in local content rules, formalised bidding process and the end of Petrobras' exclusive rights to the pre-salt fields have made Brazil much more appealing for foreign oil companies. These changes have lowered the breakeven cost of pre-salt to \$40 a barrel, \$5 a barrel lower than seven years ago.

Brazilian President Michel Temer's administration loosened the local content rules which stated that certain equipment and services for oil producers must be provided by domestic suppliers. These rules were placed to protect domestic industries which often lagged global competitors in technical expertise. Coupled with strong unions and regulations, this put oil companies in the position of facing large fines or waiting years more to get oil production online. The local content rules also amounted to an additional exploration and production tax, creating bottlenecks, according to Wood Mackenzie.

In 2017 and 2018, under Temer, fines have been rolled back from 40% to 75% depending on the category and local content requirements have also been matched to levels operators were able to achieve. As a result the world's largest oil companies have bid aggressively in recent auctions for Brazil's coveted offshore pre-salt play.

These change in rules and future investment however may be short-lived dependent on the outcome of the Brazilian election in October. The winner will be able to point a new director to ANP (Brazil's energy regulator) in 2020 with the power to shape energy policy.

Wood Mackenzie estimates Brazil will be able to produce ~4.5 mb/d by 2023 as around 20 FPSOs (Floating Production Storage Offloading vessels) come online to drill for pre-salt oil due to recent reforms in Brazil.

## **Canada**

Canada is sitting on top of the world's largest deposit of crude oil estimated to be 1.8 trillion barrels mainly in the state of Alberta. However, most of this oil is unrecoverable due to it being too costly to extract. Canada's proven reserves stand at around 171 billion barrels, 98% of which are oil sands.

Canada produces 4.7 mb/d making it the fourth largest oil producer in the world. 64% of Canadian production is of oil sands and 99% of Canada's oil exports go to the United States. Active rigs have fallen from their 2011 high of 429 to 205 in 2017.

The Canadian Association of Petroleum Producers (CAPP) expects Canada's oil production to rise to 5.6 mb/d by 2035 an increase of 0.9 mb/d in 2018. This growth is expected to come from Alberta's oil sands. Total oil sands production is expected to reach 4.2 mb/d from its current level of 2.65 mb/d.

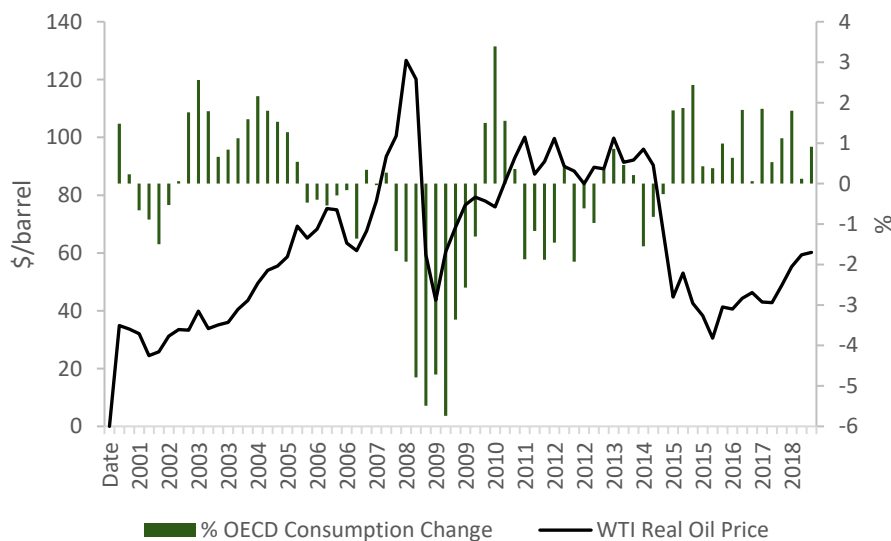
A wide range of measures have been implemented to ensure oil sands are economical to extract. Cenovus Energy Inc estimates its breakeven price is \$40 a barrel down from \$60 a barrel in 2014. Costs have been cut by reducing the amount of steel in well pad construction, downsizing workforces. New production techniques have driven down the amount of steam required to bring the bitumen to surface. These new productivity improvements are expected to enable Canada to ramp up oil production in the future of previously uneconomical oil sands deposits.

Oil sand capex has fallen in 2017 for a fourth consecutive year to \$45 billion. The greatest potential in Western Canada is located in Montney and Duvernay formations, expected to contribute 500,000 b/d by 2026. In Eastern Canada, oil production is expected to rise by 290,000 b/d by 2025 from major offshore projects including Hebron, Hibernia, Terra Nova and White Rose.

## OECD Demand

The Organisation of Economic Cooperation and Development (OECD) is a group of 36 of the comparatively most developed countries around the world, including Australia, Germany, USA and the UK. It's helpful to separate oil demand between OECD and non-OECD countries as different factors affect their consumption of crude oil.

The Norwegian financial services firm DNB has forecasted that world oil consumption to grow by 1.3 mb/d in 2018, however 1.2 mb/d of this will be from non-OECD countries. This is expected due to the higher price elasticity for oil in OECD countries as oil prices rise from their 2015-16 lows. The OECD's own forecasts are also estimating that their consumption for crude for their members will remain flat in 2018 and decline over the next five years from a current 47.4 mb/d to 46.8 mb/d in 2023.



Source: EIA

Demand for crude oil in OECD countries is typically driven more from the transport sector in comparison to less developed countries, especially through the use of personal motor vehicles. Most OECD governments implement higher fuel taxes in order to encourage improved fuel economy of vehicles and the use of alternative power for vehicles such as electricity. Currently the effect on oil consumption from higher prices is notable. OECD governments are already making plans to eradicate the use of petrol and diesel powered vehicles with the UK and France expecting to introduce bans by 2040, Germany and the Netherlands in time for 2030 and Norway by 2025. Car manufacturers are also doing their part in helping consumers switch with some of the largest manufacturers such as Volvo, Ford and Volkswagen all introducing plans to increase their range of electric vehicles as well as invest in research for the development of new vehicles. However, currently the electric vehicle market is a drop in the ocean compared to the conventional car market. The world currently consumes around 100 mb/d and the global car fleet accounts for approximately 20 mb/d or one fifth of total oil consumption. BP's energy Outlook 2035 forecasts that the number of electric vehicles will increase from 1.2 million to around 300 million in 2040. While this is a significant increase, BP also estimates that the global car fleet will double, meaning adding another billion cars to reach nearly 2 billion cars on the world's roads. This will contribute 5 mb/d growth in oil consumption by 2035, according to BP, so electric vehicles most likely won't have a significant impact on the demand for oil. Fuel efficiency however will have a larger impact on oil demand according to BP. In BP's Energy Outlook 2018, they expect fuel efficiency to grow at 2-3% pa to 2040, driven by tighter regulations and government targets. In the EU in 2040, cars on the road will be 70% more efficient

than in 2000, with an internal combustion engine consuming 3 litres per 100km in 2040, compared to 7 litres in 2000 and 5 litres today.

Another reason for slower growth in oil consumption in OECD countries is due to the structure of their economies. In contrast to non-OECD countries, the OECD economies have a higher composition of services rather than manufacturing sectors. The service sector in general requires less oil products to function than manufacturing. This means that even when OECD countries experience stronger economic growth, there isn't as equally strong surge in demand for oil in these economies.

New rules from the International Marine Organisation (IMO) will ban ships using fuel with a sulphur content higher than 0.5% compared to the 3.5% employed currently, unless ships are equipped to clean up its sulphur emissions, which will come into effect in 2020. The global refining industry will need another 2.5 mb/d of crude oil to make distillates for cleaner fuel for the new regulations, according to Robert Herman refining executive at Phillip66. The easiest way for refiners to produce fuel with less sulphur, is to buy and produce crude with less sulphur. This could change demand dynamics for different grades. Lighter 'sweet' crude with less sulphur such as North Sea Brent, which is the benchmark for three quarters of the world's crude will be favoured more than more 'sour' crude with more sulphur from countries such as Venezuela, Mexico and Ecuador.

## Non-OECD Demand

Virtually all growth in oil consumption over the next five years will come from non-OECD countries. Developing countries experience rapid economic growth and accompanying this is higher consumption of oil. Commercial and personal transportation activities requires a lot of oil and are influenced heavily by economic activity in emerging markets. Manufacturing consumes oil as fuel - developing countries have more energy intensive industries such as manufacturing or use it as feedstock, and in some non-OECD countries oil remains as the fuel for power generation.

The IEA expects global oil consumption to rise by 6.9 mb/d by 2023, with around half of that growth expected to come from China and India alone. Globally, transportation constitutes around 60% of oil demand and as developing economies expand, they have a greater need to transport people and goods. Vehicle ownership per 1000 people in emerging markets is a fraction in comparison to developed markets, providing tailwinds for future oil consumption as incomes rise in emerging markets. China is now the second largest oil consumer in the world, with its rising oil consumption being a major contributor to incremental growth in worldwide oil consumption.

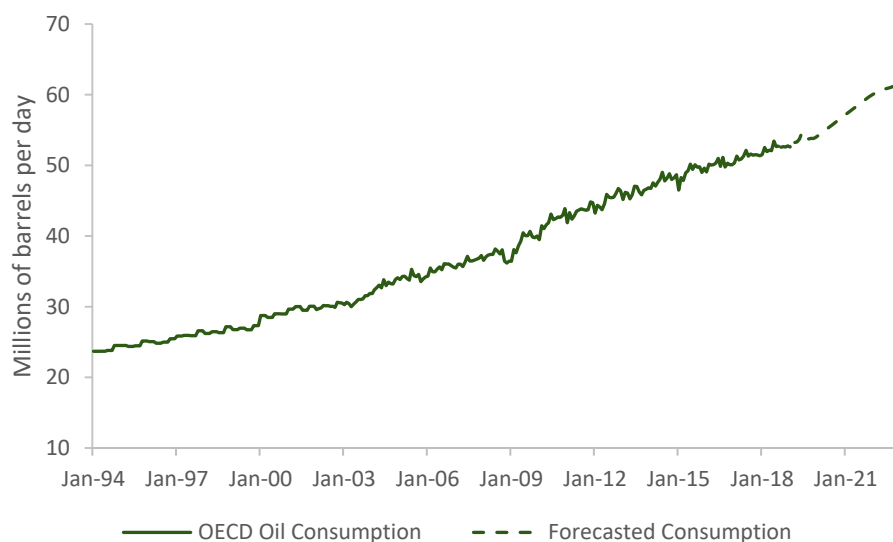
Based on estimates from the EIA, much of the future growth in world energy consumption will occur in Asia outside the nations of the OECD. Although China and India account for most of the area's current energy consumption, the EIA estimates growth in other Southeast Asian nations including Indonesia, Thailand and Malaysia. These countries collectively account for 7% of the world's primary energy consumption in 2015 which is expected to rise to 10% by 2040 according to the EIA. These countries' gross domestic product is projected to nearly triple in this time period outpacing population growth of 30%. Demographic and economic trends lead to a strong increase in average income per household, from around \$5000 in real 2010 dollars, to more than \$12,000 by 2040.

The nations of other non-OECD Asia share similar structural characteristics of China and India, such as low cost of labour, favourable cultures for economic growth, rising personal income and plenty of productive capacity. The agricultural sectors in these nations are expected to decline as a share of the total economy, to be replaced with construction industries to accommodate rising urbanisation. Energy-intensive manufacturing, motor vehicles and chemical production are also expected to grow rapidly, all needing crude oil. In aggregate, industrial energy consumption in other non-OECD Asia excluding China and India is projected to increase by 60% between 2015 and 2040.

Urbanisation and rising standards of living are key components to rising oil use in transportation and in buildings in other non-OECD Asian economies. The EIA forecasts that passenger travel to more than triple between 2015 and 2040. In 2015, about 30% of travel in these nations was in automobiles and by 2040 the EIA expects this to reach 50%. The growing market share of travel from automobiles is expected to come from the decline of two and three wheel vehicles and mass transit which are relatively more fuel efficient than automobiles. As these economies grow rapidly, other forms of travel will increase. Freight travel and air travel which are oil intensive increases as a result of higher manufacturing activity, improving infrastructure and rising personal incomes.

Low vehicle penetration in emerging markets, poses non-OECD thirst for oil in the future. China currently has 83 vehicles per 1,000 inhabitants, just a fraction of 797 vehicles per 1,000 people in the United States. India's passenger vehicle density is set to double by 2020 on the back of low current vehicle penetration and a population in which 66% of people are below to age of 35, according to EY. Their report says that the number of passenger vehicles will grow from 29 million in 2015 to more than 48 million by 2020. The IEA expects car ownership in India to grow by 775% over the next 24 years. The report adds that the number of vehicles will grow from the current 20 per 1,000 people to 175 by 2040 and for overall road passenger vehicle activity to increase by more than six times. It's worth noting however, that BP estimates that the impact on fuel demand will be largely offset by fuel efficiency gains. BP forecasts litres per 100km in China to fall substantially from 7 litres to around 2.5 in 2040.

Non-combusted use of fuels (feedstocks for petrochemicals, lubricants and bitumen) will most likely become an important component of demand growth for oil. There is a more limited scope for efficiency gains when oil is used as a feedstock rather than as an energy source. Oil accounts for nearly two-thirds of the growth in non-combusted use of energy to 2040 according to BP. Petrochemicals will be the fastest source of oil demand, especially from China, according to the IEA. The IEA expects 1.7mb/d of demand growth coming from ethane and naphtha alone. Economic growth lifting people into the middle class from non-OECD countries will result in higher demand for goods and services. A lot of these needing chemicals derived from oil, including personal care items, food preservatives, fertilisers, furnishings, paints and lubricants for automotive and industrial purposes, all tailwinds for non-OECD oil consumption growth.



## Demand and Supply Schedules

	2010	Change	2011	Change	2012	Change	2013	Change	2014	Change	2015	Change	2016	Change	2017	Change	2018
OECD Demand	47.1	-0.6	46.5	-0.5	46	0.1	46.1	-0.3	45.8	0.7	46.5	0.4	46.9	0.4	47.3	0.3	47.6
Non-OECD Demand	41.5	1.2	42.7	1.6	44.3	1.6	45.9	1.4	47.3	1.2	48.5	0.9	49.4	1.1	50.5	2.0	52.5
<b>Total Demand</b>	<b>88.6</b>	<b>0.6</b>	<b>89.2</b>	<b>1.1</b>	<b>90.3</b>	<b>1.7</b>	<b>92</b>	<b>1.1</b>	<b>93.1</b>	<b>1.9</b>	<b>95</b>	<b>1.3</b>	<b>96.3</b>	<b>1.5</b>	<b>97.8</b>	<b>2.3</b>	<b>100.05</b>
Non-OPEC Supply	50.1	0	50.1	0.6	50.7	1.4	52.1	2.3	54.4	1.4	55.8	-0.7	55.1	0.5	55.6	5.07	60.7
OPEC NGL's & non conventional oil	5.5	0.4	5.9	0.3	6.2	0	6.2	0.2	6.4	0.2	6.6	0.2	6.8	0.1	6.9	-0.6	6.3
Global Biofuels	1.8	0	1.8	0.1	1.9	0.2	2.1	0.1	2.2	0.1	2.3	0	2.3	0.1	2.4	-2.4	
<b>Total Non-OPEC Supply</b>	<b>57.4</b>	<b>0.4</b>	<b>57.8</b>	<b>1</b>	<b>58.8</b>	<b>1.6</b>	<b>60.4</b>	<b>2.6</b>	<b>63</b>	<b>1.7</b>	<b>64.7</b>	<b>-0.5</b>	<b>64.2</b>	<b>0.7</b>	<b>64.9</b>	<b>2.07</b>	<b>67.0</b>
<b>Call on OPEC Crude &amp; Stocks</b>	<b>31.2</b>	0.2	<b>31.4</b>	0.1	<b>31.5</b>	0.1	<b>31.6</b>	-1.5	<b>30.1</b>	0.2	<b>30.3</b>	1.8	<b>32.1</b>	0.8	<b>32.9</b>	0.2	<b>33.1</b>
OPEC Supply	29.7	0.5	30.2	1.5	31.7	-0.9	30.8	-0.1	30.7	1.1	31.8	1	32.8	-0.4	32.4	-0.3	32.1
<b>Implied World Oil Stock Change</b>	<b>-1.5</b>		<b>-1.20</b>		<b>0.20</b>		<b>-0.80</b>		<b>0.60</b>		<b>1.50</b>		<b>0.70</b>		<b>-0.50</b>		<b>-1.0</b>
<b>Total Supply</b>	<b>87.1</b>	<b>0.9</b>	<b>88</b>	<b>2.5</b>	<b>90.5</b>	<b>0.7</b>	<b>91.2</b>	<b>2.5</b>	<b>93.7</b>	<b>2.8</b>	<b>96.5</b>	<b>0.5</b>	<b>97</b>	<b>0.3</b>	<b>97.3</b>	<b>1.8</b>	<b>99.1</b>

<b>5 Year Forecast</b>	2023
OECD Demand	46.8
Non-OECD Demand	59.2
<b>Total Demand</b>	<b>106</b>
Non-OPEC Supply	72.7
OPEC Supply	32.9
<b>Total Supply</b>	<b>105.6</b>
<b>Implied Shortage (-)/ Surplus (+)</b>	<b>-0.4</b>