SECOND QUARTER 2020

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Natural Resource Market Commentary

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ON THE VERGE OF AN ENERGY CRISIS

Table of Contents

The oil market has never been more tumultuous than over the last four months. Fears over the COVID-19 pandemic combined with a OPEC market share war left investors worried that storage capacity would be exhausted in May. A huge wave of panic selling into the expiration of the May 2020 WTI contract on April 20th drive oil prices to nearly -$40 per barrel.

We have now completed a full investment cycle in energy that began forty years ago. In 1980, investors worried the world was running out of oil. Only one year earlier, millions of Americans waited in gas lines. Three years earlier, President Carter had interrupted broadcast television to inform the American people they were running out of natural gas. Oil prices climbed higher and higher, making energy related stocks the most popular investments by far. By the end of 1980, six out of the top ten companies by market capitalization were energy related as was one third of the S&P 500. Schlumberger was the quintessential "must own" stock of the cycle, and for those that are interested we have written an essay dedicated to its investment odyssey at the end of this letter.

GOEHRING & ROZENCWAJG
Natural Resource Investors

Things today could not be more different. By the end of March, the energy component of the S&P 500 hit 2.8% -- by far the lowest on record. Instead of peak oil supply, investors now worry about peak oil demand. Even though prices quickly recovered and stand at $40 today, the conventional wisdom says that curtailed production will come rushing back, driving prices lower yet again. The average investor believes the age of oil, which started when Colonel Drake drilled his first well in western Pennsylvania, is over.

We do not agree. Instead, our models tell us that we on the verge of an energy crisis that could last for many years to come.

To our long-time readers, we surely sound like a broken record. We first turned bullish on oil in the first quarter of 2016 after prices collapsed to $26 per barrel. We have largely remained bullish ever since. On the surface, this appears to have been a very bad call. Where have we been right and where have we been wrong?

Oil prices bottomed on February 11, 2016 at $26 per barrel and today trades for $40. Even after the incredible turmoil of the first five months of 2020, oil is over 50% higher today. How does this compare with other commodities? Gold, the most popular commodity at present, bottomed at $1,050 per ounce on December 2015 and today approaches $1,975 for an 85% return. Copper has also been popular given its association with electric vehicles and renewable power. It bottomed on January 17, 2016 at $1.95 per pound and today trades at $2.85 per pound, a return of 45%.

Just looking at the commodity prices, one would expect producers of all three commodities to have done well over the last four years, with gold producers leading the pack followed by oil and then copper. This has certainly not been the case. While gold and copper stocks have been strong performers, energy related investments have been terrible. Since bottoming in early 2016, gold equities (as measured by the GDX ETF) have advanced 180% and copper equites (as measured by the COPX ETF) are now up 100%. Exploration and production companies (as measured by the XOP ETF) fell by 44%. Even more conservative energy investments such as the integrated producers, refiners, and pipeline stocks are down 15% (as measured by the XLE ETF).

We have been right in our assessment of the energy markets, but that has not translated into equity performance. What explains this seeming paradox? Our mistake has been in severely underestimating the volatility in oil prices. Our bullish view on oil markets has always been based on the idea that the shales were maturing faster than expected. Since US shale has been the only bright spot in the non-OPEC world over the last decade, we concluded the market would quickly tighten once its growth slowed.

Over the last five years this is exactly what has happened. One way to measure physical tightness in oil markets is through the contango – or how the future price compares to the spot price. Somewhat counterintuitively, a well-supplied market actually has a large contango (futures prices are higher than spot) while a tight physical market has a negative contango known as a backwardation (futures prices are lower than spot). As this chart clearly points out, the oil market became much tighter between 2016 and 2019 as measured by the contango.

FIGURE 1 12 Month WTI Contango (% of Spot)

Source: Bloomberg

This physical tightness has done little to change investors' bearish psychology. Concerns about EVs and shale growth have dominated the headlines. Any time there has been the slightest short-term surplus in crude markets over the last five years, energy shares have crashed. In the subsequent period of market tightness, they have rallied back but never by enough to offset the selloff. Equity prices have drifted lower and lower as a result.

Consider, for example the sell-off in the fourth quarter of 2018. President Trump convinced Saudi Arabia and OPEC to aggressively expand production to offset lost volumes from the pending Iranian oil sanctions. Once they agreed, Trump surprised the market by not implementing the oil sanctions at all. This led to a short-term crude imbalance that was quickly addressed by Saudi Arabia and the rest of OPEC. Nevertheless, oil and oil-related stocks pulled back by an impressive 40% during the fourth quarter of 2018. While oil rallied back over the next few months, the related stocks lagged. In the second quarter of 2019, oil prices again pulled back in response to concerns over President Trump's trade war with China. From April to June, oil prices pulled back 22% while the related stocks fell by 25%. Once again, oil prices rallied back nearly 20% over the rest of the year while the related equities fell another 5%.

Most recently, the oil market dealt with large-scale demand disruption caused by the coronavirus that resulted in the bizarre experience of negative oil prices. Even though the negative WTI contract price received all the attention, we should point out the Brent oil contract, which can cash settle, never traded below $27 per barrel.

After each of these sell-offs, investors have become more and more bearish. Even though oil prices have bounced back quickly after each episode (a testament to how tight the physical market is), the stocks have not. Since 2016, oil has nearly kept up with gold and yet oil related investments are nearly 50% lower while gold stocks advanced by 200%.

Everyone is convinced that the shales will keep global oil markets in perpetual surplus, but instead we would argue the "age of shale" is largely passed.

The overwhelming bearishness around demand is about to change as well. Oil demand has only fallen a fraction of what was originally feared by most oil market watchers a few months ago. Furthermore, there is more and more evidence emerging that a steep "V-shaped" recovery is now taking place in energy demand.

Because of the huge investment importance of what is happening in global energy markets today, the bulk of this letter is dedicated to energy. We remain bullish on gold, uranium, copper, and agriculture, but feel that the most topical issues today surround energy. Please do not think our views on other natural resource investments have changed just because we have not written about them this quarter.

Energy related investments have been poor performers since 2016, despite relatively tight fundamentals. We believe this is about to change and energy related equities will deliver very strong returns going forward. Please read on.

The Coming Oil Crisis

"WE ARE ON THE CUSP OF A GLOBAL ENERGY CRISIS."

We are on the cusp of a global energy crisis. Like most crises, the fundamental causes have been brewing for several years, but have lacked a catalyst to bring them to the attention of the public or to the average investor. This one is rooted in the underlying depletion of the US shales along with the chronic disappointments in non-OPEC supply in the rest of the world. The catalyst is the coronavirus.

Global efforts to contain the coronavirus resulted in widespread quarantines and travel restrictions. Crude stockpiles rose sharply and seemed likely to reach maximum capacity within a matter of weeks. In April, OPEC+ announced the largest emergency production cuts ever totaling 8 mm b/d. Collapsing prices forced production in the non-OPEC+ world to be shut-in as well and together helped moderate the inventory builds. In our last letter, we argued that once inventories approached full levels, the oil market would be forced into balance more quickly than anyone believed possible. In retrospect, this is exactly what happened. Traders realized the physical market had balanced and prices rose quickly. Less than two months after WTI reached -$37 per barrel it normalized to $40.

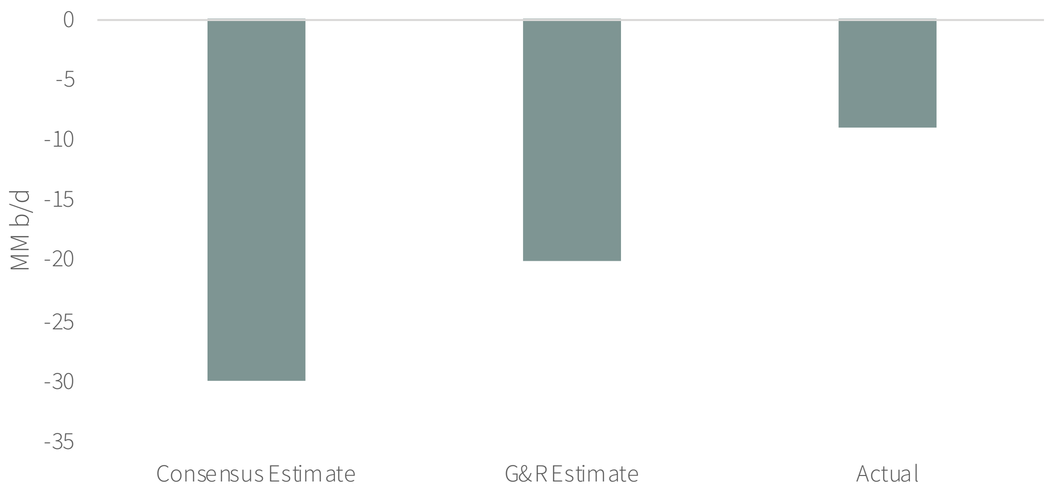
The oil market is currently enjoying a momentary period of calm. Our models tell us this calm will be short lived. Global energy markets in general and oil markets in particular are slipping into a structural deficit as we speak. We believe that energy will be the most important investment theme of the next several years and the biggest unintended consequence of the coronavirus.

Given the complexity of today's oil markets, we will first summarize where demand and supply currently stand before going into each driver in greater detail.

"DEMAND WAS NOT IMPACTED NEARLY AS MUCH AS ORIGINALLY FEARED"

In retrospect, demand was not impacted nearly as much as originally feared. Most energy analysts warned global oil demand would fall by 30% (or 30 mm b/d) in April and May. We felt these estimates were far too severe and wrote that demand would likely fall by 23 mm b/d. Our models (which are very different than consensus and will be discussed in a moment) now suggest that demand fell by 8 mm b/d in April and May and less than 10 mm b/d for the second quarter as a whole. While this still represents the largest demand slump in history, it is nearly 70% less than originally feared by most analysts.

FIGURE 2 Global Demand Y/Y Change



Source: International Energy Agency, GR Models, Analyst estimates.

Not only was the decline much less than expected, but the recovery has been much faster as well. Core petroleum demand in the US has now regained 70% of its total peak-to-trough decline in less than five months. Preliminary Chinese customs data suggests that second quarter petroleum demand was up 10% year-on-year – the strongest reading ever. Despite air travel being the slowest to recover, it is beginning to normalize as well. Cornerstone Analytics reports global daily air traffic is only 10% lower than the start of the year compared with 65% lower in April.

On the other hand, supply contracted materially in response to the coronavirus. OPEC+ announced an 8 m b/d production cut that took effect in May and so far compliance has been high. Non-OPEC+ production fell dramatically as concerns surrounding full storage and record low prices led producers to actively shut-in wells. The IEA reports non-OPEC+ production fell by nearly 5 mm b/d between April and June led mostly by the US and Canada -- very much in line with our predictions from the last letter.

The sharp decrease in supply along with better than expected demand kept inventories from hitting maximum capacity in May. As investors and traders realized the acute phase of the dislocation had passed, WTI rose steadily from a low of -$37 per barrel on April 20th to $40 by June 30th.

Investors' focus has now shifted to how supply can be brought back to meet recovering demand. While most investors believe production will be easily restored, our models tell us something vastly different. While OPEC+ production will likely rebound, non-OPEC+ supply will be extremely challenged. Instead of recovering, our models tell us that non-OPEC+ production is about to decline dramatically from today's already low levels.

"THUS FAR, THE SLOW-DOWN IN NON-OPEC+ PRODUCTION HAS COME ENTIRELY FROM PROACTIVELY SHUTTING IN EXISTING PRODUCTION. "

Thus far, the slowdown in non-OPEC+ production has come entirely from proactively shutting in existing production. These wells were mostly old and only marginally economic before prices collapsed. Going forward, production will be impacted by a different and longer-lasting force. Low prices led producers to curtail nearly all new drilling activity. As recently as March 13th, there were 680 rigs drilling for oil in the United States. In less than four months, the US oil directed rig count fell by 75% to 180 – the lowest level on record. There is at least a two-month lag between drilling a well and first production, suggesting

"LOW PRICES LED PRODUCERS TO CURTAIL NEARLY ALL NEW DRILLING ACTIVITY."

hardly any of the drilling slowdown impact has shown up in production data yet. That is about to change.

Shale wells enjoy strong initial production rates but suffer from sharp subsequent declines. Basin production falls quickly unless new wells are constantly drilled and completed to offset the base declines. Considering US shale production was already falling sequentially back in November when the rig count was above 700, today's 180 rigs all but guarantee production will collapse going forward. Nevertheless, the IEA predicts US production will grow by 500,000 b/d from the June lows to the end of the year, presumably driven by shut-in production being brought back online. Our models tell us this simply cannot happen. Instead of growing, US production will fall materially from here. As we go to print, the EIA just released its monthly report with data through May showing production fell by another 2 m b/d sequentially. This is the largest monthly production drop on record and nearly twice as much as originally expected by most analysts. Our models tell us more surprises like this are forthcoming.

"CONSIDERING US SHALE PRODUCTION WAS ALREADY FALLING SEQUENTIALLY BACK IN NOVEMBER WHEN THE RIG COUNT WAS ABOVE 700, TODAY'S 180 RIGS ALL BUT GUARANTEE PRODUCTION WILL COLLAPSE GOING FORWARD."

Low prices have led to a sharp drilling slowdown in the rest of the world as well. Between February and June, the non-US rig count fell by 40% to 800 – also the lowest on record. We have often written about the depletion problem facing the non-OPEC+ world outside of the US shales. Over the last decade, this group has seen production decline slowly and steadily as a dearth of new large projects has not been enough to offset legacy field depletion. By laying down half their rigs, this group has also ensured that future production will be materially impacted.

"ANALYSTS CONTINUE TO FOCUS THEIR ATTENTION ON WHAT HAS ALREADY HAPPENED (SHUT-IN OF EXISTING PRODUCTION) INSTEAD OF LOOKING AT WHAT IS YET TO COME."

Analysts continue to focus their attention on what has already happened (shut-in of existing production) instead of looking at what is yet to come. The unprecedented drilling slowdown over the last three months is only now starting to impact production. Going forward, supply will plummet leaving the market in an extreme deficit starting now.

Investors are complacent because inventory levels remain high and are expected to buffer any future imbalance. This is no different than the peak of the last cycle in July 2016— an especially important fact no energy analysts have commented on. In 2016, OECD inventories were 450 mm bbl above long-term seasonal averages and wisdom dictated it would take years (if ever) to work off the overhang. On July 31st 2016, with oil at $40 per barrel, analysts expected prices to remain lower for longer. In fact, it only took 18 months to work off the overhang. By the summer of 2018, inventories were back to near long-term averages and prices had rallied to $87 per barrel.

"COLLAPSING SUPPLY THIS CYCLE WILL DRAW INVENTORIES DOWN MUCH FASTER THAN IN 2016-2018, A PERIOD THAT ENJOYED ROBUST SHALE GROWTH. INSTEAD OF WORKING OFF THE INVENTORY OVERHANG IN 18 MONTHS, OUR MODELS SUGGEST THIS COULD HAPPEN AS SOON AS THE END OF THE YEAR ."

Despite the unprecedented disruptions caused by the coronavirus, June OECD inventories stood only 400 mm bbl above long-term average levels – less than the 2016 high point. Collapsing supply this cycle will draw inventories down much faster than in 2016-2018, a period that enjoyed robust shale growth. Instead of working off the inventory overhang in 18 months, our models suggest this could happen as soon as the end of the year or the first half of 2021.

Our outlook is vastly different than most investors. The consensus opinion holds that demand will take years to recover to pre-pandemic levels while production will once again surge as soon as oil reaches $50 per barrel. To understand where we diverge from the consensus, we would like to go into greater detail around each driver.

Global Demand

The impact of the coronavirus on global oil demand was drastically less than originally feared. Many oil analysts expected quarantines and travel bans to impact demand by as much as 30 mm b/d during the second quarter. Instead, our models suggest that the impact on demand was nearly 70% less and instead of falling by 30 m b/d only fell by 10 mm b/d during the quarter.

The difference between our estimates and the consensus opinion once again revolves around the so-called "missing barrels," which have reemerged as a key issue over the past three months. In May, the IEA released its monthly Oil Market Report in which it estimated second quarter demand would fall by 20 m b/d year-on-year to 79.3 m b/d. Such a drop would be consistent with a single-month drop of 30 mm b/d year-on-year for May – the prevailing bear case at the time.

As the quarter progressed, however, it became clear that OECD inventories were not building as expected. According to the IEA's figures, OECD inventories should have grown by 645 million barrels in April. Instead, they only built by 145 million barrels, resulting in a massive 500 million "missing" barrels.

Similarly, May OECD inventories should have built by 6.5 mm b/d or 200 mm bbl total. Instead, inventories built by less than half that amount. While we only have preliminary inventory data for June, it suggests that OECD stocks did not build as much as the IEA's supply and demand data suggest either.

Long time readers of our letters know that we believe "missing barrels" reflect understated demand. Over the past decade, there has been a chronic bias in the IEA estimates for non-OECD demand, and we believe this time is no different. Our models suggest that emerging market oil demand has held up much better than widely appreciated.

Emerging markets have been critical to global energy markets for many years. However, it is helpful to think back to a period before their ascendency to understand how much things have changed. In the late 1970s high prices and weak economic conditions led to a 10% drop in oil demand between 1979 and 1982. The developed world made up two-thirds of all oil demand and fell 15% while the emerging markets made up the remaining one-third and grew slightly. The developing world was clearly the growth engine, but it only represented a small fraction of total demand. As a result, it took a decade before global oil demand surpassed its old 1979 high.

Conditions during the Global Financial Crisis were radically different. By 2007 half of global oil demand was coming from the emerging markets. Despite a ten-fold increase in oil prices and the worst financial panic since the Depression, global demand only fell by 2% from 2007 to 2009. Instead of taking a decade to recover, demand surpassed the old highs within 18 months. One decade later, global oil demand is now 15% higher than in 2007. The growth engine for global oil demand (the emerging markets) had become considerably bigger.

Last year, emerging markets exceeded 60% of global oil demand – an all-time high. It is no surprise that global demand is therefore coming in much stronger than expected during this downturn as well.

Adjusting for the "missing barrels," we believe second quarter demand fell by 10 m b/d to average 89.5 mb/d. The IEA expects demand to rebound to within 4 m b/d of normal by the end of the year, but this figure is likely dramatically understated as welI. Instead, we believe fourth quarter demand will be within 1 m b/d of normal and could exceed 100 m b/d. For 2021, our models suggest demand will average at least 100 m b/d – nearly 2.5 mm b/d higher than the IEA is currently projecting.

Consensus opinion believes it will take until the end of 2021 for demand to reach normal pre-coronavirus levels. We would argue we are much closer to normal levels to begin with and demand will soon exceed prior highs.

Non-OPEC+ Supply

Record low prices and fears of filling inventories led to the sharpest drop in non-OPEC+ production in history. Between April and June, non-OPEC+ production collapsed by nearly 5 mm b/d or 10%. While most investors expect production to rebound from here, our models tell us supply declines are set to accelerate materially. To date, all the production slowdown has come from actively curtailing existing production. At the same time, low prices have led drillers to lay down most of their rigs. The impact of this drilling slowdown has not yet been felt but going forward will be the most important driver of global oil markets. While some of the curtailed production may be brought back online, it is not nearly enough to make up for the slowdown in future drilling needed to offset base declines.

US Production

To understand why, consider the situation in the US. Between April and June, production declined by 2.8 m b/d, representing half the total non-OPEC+ slowdown. We estimate that 1.4 m b/d came from legacy stripper wells and Gulf of Mexico offshore production. We believe most of this production will not be brought back online. The remaining 1.4 m b/d came from a combination of shutting in newer shale wells and from normal shale basin declines. We were able to use our neural network to estimate how much of the decline was attributable to each source. By comparing how existing shale wells ought to have produced under normal conditions with how they actually flowed, we conclude that 650,000 b/d of shale production was proactively shut in between April and June. The remaining 750,000 b/d decline was the result of not having drilled enough new wells to offset basin depletion.

It takes two months from when a well is drilled and completed until it reaches maximum production. Therefore, shale production in the April-June period was the result of wells drilled between February and April. Approximately 850 wells were completed per month during that time, which was not enough to offset the 40% base decline rate of the shale basins.

Although seldom mentioned, shale production began falling sequentially in December 2019 – months before the coronavirus. At that point, the shale industry was completing 1,000 wells per month and yet production still fell by 50,000 b/d. Therefore, it is not surprising that production declines accelerated to 250,000 b/d per month for the three months ending April, as the number of completed monthly wells fell from 1,000 to 850.

Investors are under the impression that low prices in April temporarily impacted produc-

"AFTER HAVING COMPLETED 850 WELLS MONTHLY BETWEEN FEBRUARY AND APRIL, THE SHALE INDUSTRY COMPLETED ONLY 280 WELLS PER MONTH IN MAY AND JUNE."

tion and that the industry is about to begin normalizing. What the market does not appreciate, however, is how sharply production is about to fall from here. After having completed 850 wells monthly between February and April, the shale industry completed only 280 wells per month in May and June – a reduction of nearly 70%. There are only 10 rigs currently drilling in the Bakken shale compared with 50 at the start of 2020 and 200 in 2014. In the Eagle Ford, the rig count has gone from 70 earlier this year to 11 today. Even in the Permian, the rig count has fallen from over 400 to less than 120 today. Since these slowdowns work with a two-month lag, they will only begin to impact production in the July and August figures.

Our neural network tells us that US production will fall by as much as 2 mm b/d during the second half of 2020 and by as much as 1.5 mm b/d in 2021 unless much higher prices encourage a substantial drilling rebound (something we do not believe will happen). The IEA expects US production to rebound from the June lows by 500,000 b/d by the end of year. This is simply not possible.

The only US volumes that can potentially be brought back online are the more recent shale wells that were actively shut in over the last two months. As we discussed, these amount to 650,000 b/d and are not nearly enough to offset the 2 m b/d of incremental declines we expect over the coming six months. Instead of growing by 500,000 b/d, we believe US production could easily fall by another 1.5 m b/d from here, even after bringing back on shut-in production.

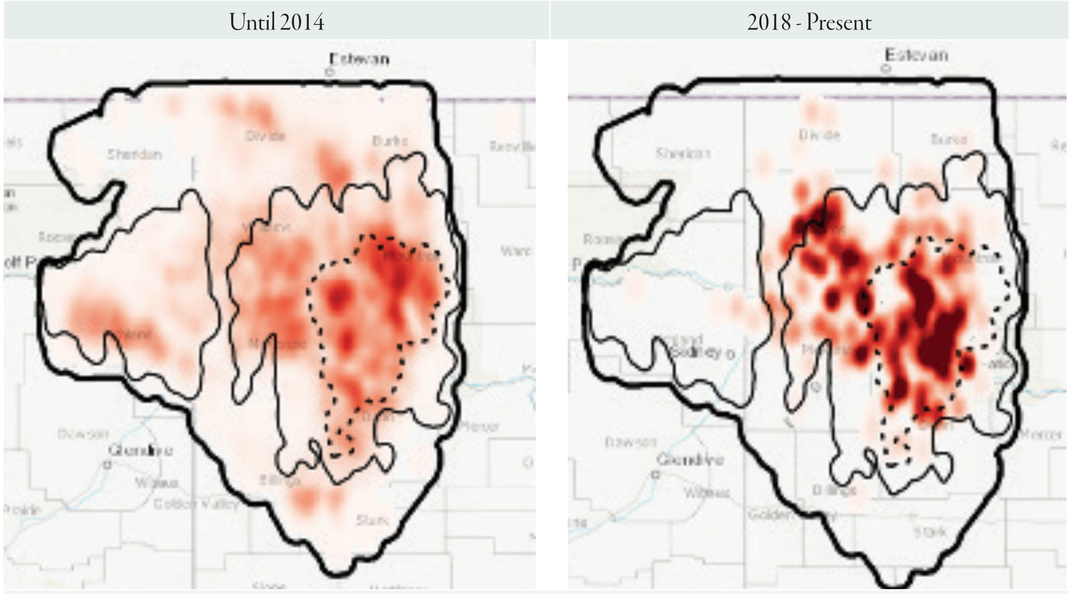
Investors believe that 2021 will bring a repeat of 2017-2018 in terms of surging shale production. As a reminder, after the 2014-2016 OPEC price war, both prices and shale activity started to rebound in 2017. By the beginning of 2018, shale production was growing faster than ever before, despite the fact the US oil rig count was still 50% below 2014 levels. Investors today are worried that any uptick in the US rig count will once again bring about a surge in shale production. Our neural network tells us this is not possible because the inventory of high-quality drilling prospects has been exhausted.

Using the Bakken as an example, let us examine what happened between 2014 and 2018. Throughout 2014, the average new Bakken well had a peak production rate of 400 barrels of oil per day. Existing wells declined by 60,000 b/d each month in aggregate in 2014. Therefore, 144 completions were needed per month to offset the base declines compared with the 206 wells that were actually brought online; production grew by 25,000 b/d per month.

Prices collapsed in 2015 and drilling activity followed. Over the next two years, monthly completions were cut in half from 200 per month to 100. The average completed well become slightly more productive going from 400 barrels of oil to 420 barrels on average. As a result, 120 new completions were needed each month to offset the 52,000 b/d of monthly declines from existing wells compared with 100 wells that actually completed. As expected, production declined consistently over this period.

By 2017, Bakken operators undertook a massive high-grading effort in which they focused exclusively on their Tier 1 acreage. Our neural network shows us that Tier 1 drilling went from 50% of all wells drilled in 2014 to 75% of all wells drilled in 2018. The migration away from Tier 2 areas towards Tier 1 is clear when looking at the following map.

FIGURE 3 Bakken Drilling Intensity by Area



Thick line represents basin boundary. Thin line represents Core Area. Dotted Line represents Best Tier 1.

Source: G&R Neural Network

Since Tier 1 wells are dramatically more productive than Tier 2 wells, the average well productivity increased by over 50% from 420 barrels of oil in 2015-2016 to 655 barrels in 2017-2018. The number of wells needed to hold production flat fell from 120 per month to less than 70 per month while the actual number of monthly completions rose only slightly from 93 to 100 over the period. Therefore, despite only a 5% increase in activity, Bakken production was able to shift from sustained declines to robust growth of over 240,000 b/d per year.

This high grading abated somewhat throughout 2019 but picked up again at the start of 2020. Our neural network estimates that by the first quarter of 2020 Tier 1 wells again made up nearly 80% of all completions in the Bakken. As a result, the average Bakken well produced 740 barrels per day in its peak month. At the same time, two years of strong production growth had increased the base decline as well, which moved from 45 to 80,000 b/d per month. As a result, we estimate that 110 monthly completions were necessary to hold production flat compared with 70 in the 2017-2018 period. Instead only 90 wells were completed per month, leaving production to fall throughout the first quarter.

"GIVEN THE FACT THAT NEARLY FOUR OUT OF FIVE BAKKEN WELLS WERE TIER 1 TO BEGIN WITH, PRODUCERS' ABILITY TO HIGH-GRADE FURTHER IS LIMITED."

Following the dislocation in April and May, only 13 wells were completed in June, compared with 90 that are needed to hold production flat. Clearly production is set to decline dramatically from here. However, given the fact that nearly four out of five Bakken wells were Tier 1 to begin with, producers' ability to high-grade further is limited. The industry is not in a position to repeat the 2017-2018 experience when a small increase in activity combined with a strong increase in high-grading quickly resulted in robust growth.

"WHILE INVESTORS DEBATE HOW QUICKLY THE 650,000 B/D OF SHUT-IN SHALE PRODUCTION CAN RETURN, THEY ARE COMPLETELY IGNORING THE UPCOMING IMPACT OF COLLAPSING ACTIVITY."

While investors debate how quickly the 650,000 b/d of shut-in shale production can return, they are completely ignoring the upcoming impact of collapsing activity. The only source of non-OPEC+ growth over the past decade has been the US shales. Unfortunately, that growth is now over; the shales will likely never regain their November 2019 highs. These trends would likely have emerged naturally over time as a dearth of Tier 1 drilling locations would have become clear. Instead COVID-19 was likely the catalyst that brought these trends to the fore.

Non-OPEC+ ex US

Outside of the US, non-OPEC+ production fell by 2 mm b/d between April and June. Most of this decline came from Canada where 1.1 m b/d of high-cost steam-assisted gravity drainage (SAGD) and legacy production was shut-in. Like the US, some of this curtailed production can be brought back online while the rest is gone forever. Recently, Canadian producers have announced their intention to bring back approximately 20% (or 200,000 b/d) of curtailed supply, but there has been no announcement about the remainder.

We have long argued that non-OPEC+ production outside of the US would disappoint over the next several years. As with the shales, COVID-19 has accelerated the timeline dramatically. Even before the recent asset impairments and reserve write-offs, Goldman Sachs estimated that non-OPEC major project reserve lives had fallen by 20 years since 2016. Given the record-setting $92 bn in oil related write-downs in the first quarter alone, the figure is likely understated.

In our letter published in mid-2018, we explained how a dearth of new major projects would lead to a decline of 500,000 b/d per year in non-OPEC+ production outside the US between 2019 and 202. We estimated new projects had added approximately 1.4 mm b/d per year which helped offset base declines and left non-OPEC+ production outside the US basically flat between 2015 and 2020. We warned that contributions from new projects would slow dramatically starting in 2020 and that production would begin to decline materially. The start-up of Johan Sverdrup in Norway and Lula field expansions in Brazil pushed our assessment out by one year but did not fundamentally change our outlook.

When we first published our results, no one agreed with us. However, in the most recent edition of their Major Projects report, Goldman Sachs acknowledges that non-OPEC major projects are set to slow dramatically. In their report, Goldman estimates that contributions from major projects are set to slow from 1-1.5 m b/d per annum over the past several years to as low as 300,000 b/d per annum going forward. In total, they are estimating nearly 8 mm b/d of "lost" new project production by 2025.

Considering that 1.4 m b/d of annual gross project additions has translated into basically no net growth (after accounting for base depletion) over the last decade, a shift to 300,000 b/d of new contributions suggests non-OPEC+ production growth will turn sharply negative starting in 2020 and continuing long into the decade.

Between now and the end of 2021, the IEA expects non-OPEC+ production outside of the US to grow by 1.4 m b/d, led mostly by a rebound in Canadian production. Instead, according to our analysis, non-OPEC+ production outside the US could decline by as much as 500,000 b/d next year before collapsing further as we progress through the decade. Goldman Sachs's latest paper agrees with our assessment. They state, "We have entered a structural phase of no non-OPEC growth." The result will be a much larger call on OPEC crude and higher prices. If anything, we believe that our original estimates that we published in the middle of 2018 were too optimistic and the actual declines going forward will be even greater.

"LOOKING AT BOTH SUPPLY AND DEMAND, WE BELIEVE WE ARE ENTERING A FULL-BLOWN ENERGY CRISIS THAT WILL TAKE MANY YEARS TO RESOLVE – A SITUATION NOT UNLIKE THE 1970S. "

Balances

Looking at both supply and demand, we believe we are entering a full-blown energy crisis that will take many years to resolve – a situation not unlike the 1970s. Instead of non-OPEC+ production averaging 51 m b/d in the second half of 2020, we believe it will likely be 49.5 mm b/d. Assuming the "missing barrels" are understated demand (which we believe is the case), then the projections for the second half oil demand are far too low. Instead of averaging 95.7 mm b/d per the IEA, we believe demand will approach near-normal levels by the end of the year. Our estimate for the second half is 98 m b/d. That would leave the call on OPEC+ at 48.6 mm b/d. Total OPEC+ is only producing 35.7 b/d as of June. According to the most recent OPEC+ agreement, the emergency cuts will begin to phase out starting in July. If OPEC+ adheres to its phased approach, production in the second half will only reach 38.2 mm b/d, leaving the market in deficit by over 10 mm b/d for two full quarters and drawing down inventories by an unfathomable 1.8 bn bbl. This level of deficit would take inventories to all-time low levels by the end of December. We should point out that even if we took all of the IEA estimates at face-value and made no adjustments for missing barrels or non-OPEC+ production, inventories will likely draw by over 6 mm b/d in the second half or 1 bn bbl – completely working off all of the current inventory overhang.

Looking into 2021, instead of loosening, we see the market getting much tighter. The IEA is overstating non-OPEC+ production. Instead of averaging 52.5 m b/d we believe it will only manage 49 m b/d based on continuing declines in the US shales. Demand will likely return to normal and could average 100 mm b/d for the full year. This would leave the call on OPEC+ at 51 mm b/d – a massive 4.5 mm b/d above their "base line" production levels from last fall. This would reduce inventories by another 1.7 bn bbl – effectively wiping out the entirety of OECD stocks.

While we do not believe it is feasible to eliminate OECD stockpiles altogether, this math shows just how dramatic the looming deficits will become. Consider yourself forewarned.

Gas Supply is Falling

North American natural gas has been in a vicious bear market for 15 years. Surging supply brought about by the shale gas revolution has resulted in a persistent surplus. Although demand has also surged over the same period, it has not been able to keep up with the unrelenting growth in production.

This is all changing as we speak.

Supply has now begun to contract, and the North American natural gas market is about to swing from long term structural surplus to deficit.

One barrel of oil contains the same energy content as six thousand cubic feet of natural gas and historically this has anchored together the price of the two fuels. From 2000 to 2005, the price of oil averaged 7.5 times the price of natural gas -- not far from the energy equivalency. The relentless supply surge beginning in 2006, combined with the environment regulations that curtailed a utility's ability to burn residual fuel oil (the most competitive fuel for natural gas), caused the energy link between natural gas and oil to break down. After the warm winter of 2011-2012, natural gas price fell below $2 per mmcf. With oil priced at

$103, the oil-natural gas ratio hit 53:1, -- almost 9 times its energy equivalent. In the 40 years of data that we keep, this is by far the highest (i.e., most bearish) oil-natural gas ratio ever.

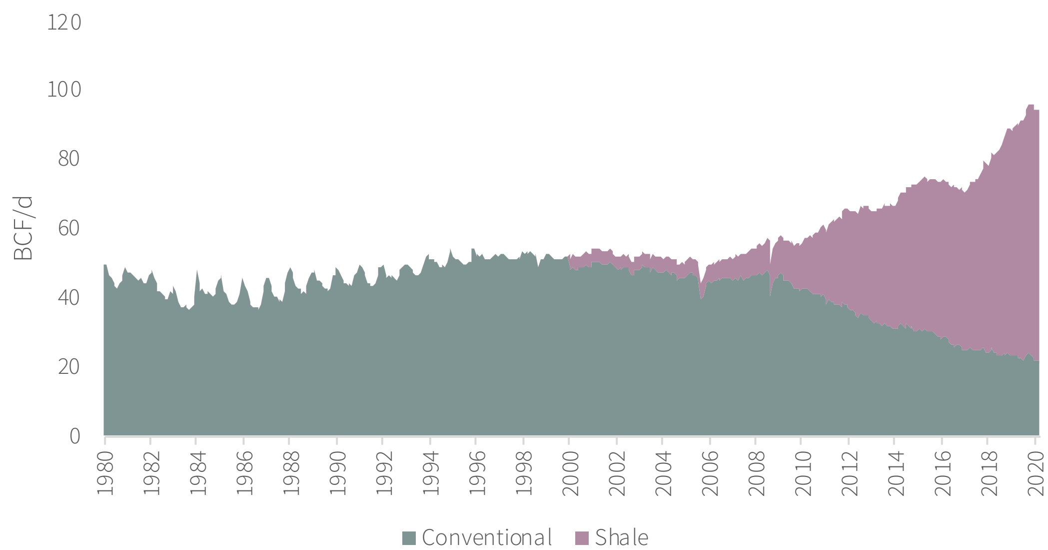
Over the last twelve months, the oil-natural gas ratio has averaged approximately 25:1 – still far below its energy-equivalency. If our research is correct, we will see the ratio fall dramatically and may even see it return to its historical six to eight-times ratio. Excess production is what caused the link to break and we are now entering into a period of declining supply.

"THE PRICE OF NATURAL GAS PEAKED IN 2005 AT OVER $15 PER MMCF, AND TODAY STANDS AT $1.65 -- ALMOST 90% BELOW THE PEAK. THE FUNDAMENTAL REASON FOR THE BEAR MARKET HAS BEEN SIMPLE: US NATURAL GAS SUPPLY SURGED DUE TO THE SHALES. "

The price of natural gas peaked in 2005 at over $15 per mmcf, and today stands at $1.65 -- almost 90% below the peak. The fundamental reason for the bear market has been simple: US natural gas supply surged due to the shales. The initial successes in the Barnett by Mitchell Energy in the early 2000s was followed by the discovery of the Fayetteville by Southwestern Energy in 2005, the Haynesville by Chesapeake Energy in 2007, and then the massive Marcellus field by Range Resources soon after.

After having declined consistently over the previous 10 years, natural gas production eventually bottomed in 2005 at 49 bcf day. By 2019 US dry gas supply had nearly doubled to 92 bcf per day -- a stunning increase of 4.6% per year. Shale dramatically changed the composition of the US natural gas supply between 2005 and 2019 as you can see in this chart.

FIGURE 4 US Dry Natural Gas Production



Source: Energy Information Agency

It was not only shale production from the gas fields that contributed to the growth. Led by surging production from the Permian and Eagle Ford oil shales, so-called associated natural gas (by-product gas produced from oil wells) grew to be 16% of US gas supply.

By 2019, primary gas production from the Marcellus and Haynesville, along with associated gas production from the Permian, had grown to almost 45% of US gas production and over 100% of total natural gas production growth.

Because the shale fields have been such prolific drivers of supply growth, many analysts do not appreciate that they eventually succumb to the same geological forces affecting conventional gas and oil fields. Production ramps up following an initial discovery, plateaus once drilling productivity begins to falter, and ultimately declines once the drilling productivity can no longer overcome the underlying depletion rate of the field.

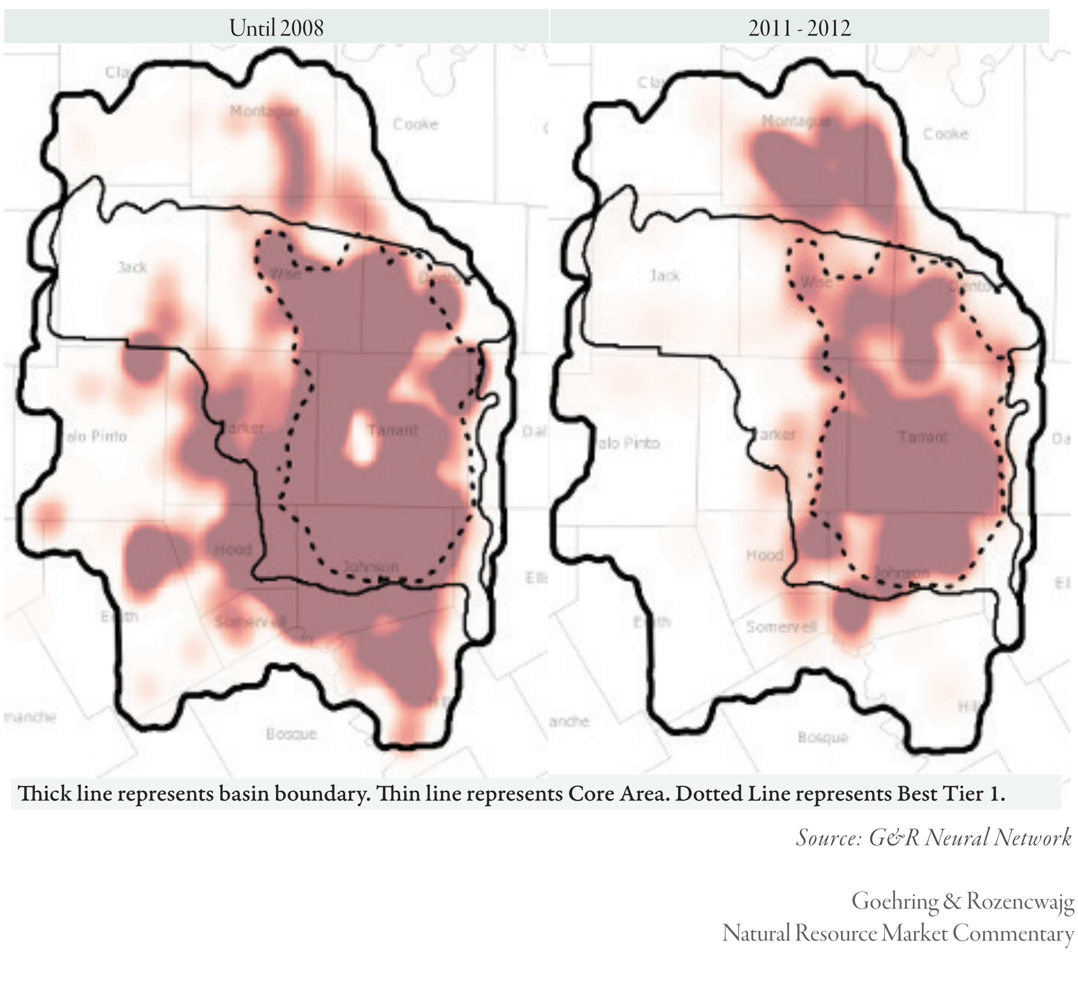
The first two shale fields put into production (the Barnett in East Texas and the Fayetteville in Arkansas) have already ramped up, peaked, and declined in the same sequence of events experienced by conventional fields. The Barnett ramped up production starting in 2001 while the Fayetteville began its steep ramp up in 2007.

The Barnett and Fayetteville both ultimately peaked in 2012 at 5.2 and 2.9 bcf/d respectively. Since then, both fields have declined by 60% and 65%, respectively, from their peak levels and production has entered into terminal decline. Today, neither field has a single rig drilling for gas.

We used our neural network to analyze both fields and we identified two important data points that coincided with the beginning of declines in both fields. First, production declined in both fields once 60% of their total "Tier 1" acreage (as defined by our neural network) had been drilled up. This coincided with the moment when 50% of the fields' total recoverable reserves had been produced.

Below is a map that shows the density of Barnett wells drilled through 2007. We have outlined what our neural network identified as the best Tier 1 acreage. As you can see, early drilling in the basin was widely scattered; operators were only just learning where the best areas were located. Eight years later, things were very different. By 2012, drillers knew exactly where the best acreage was located and were rapidly drilling it out.

FIGURE 5 Barnett Drilling Intensity by Area

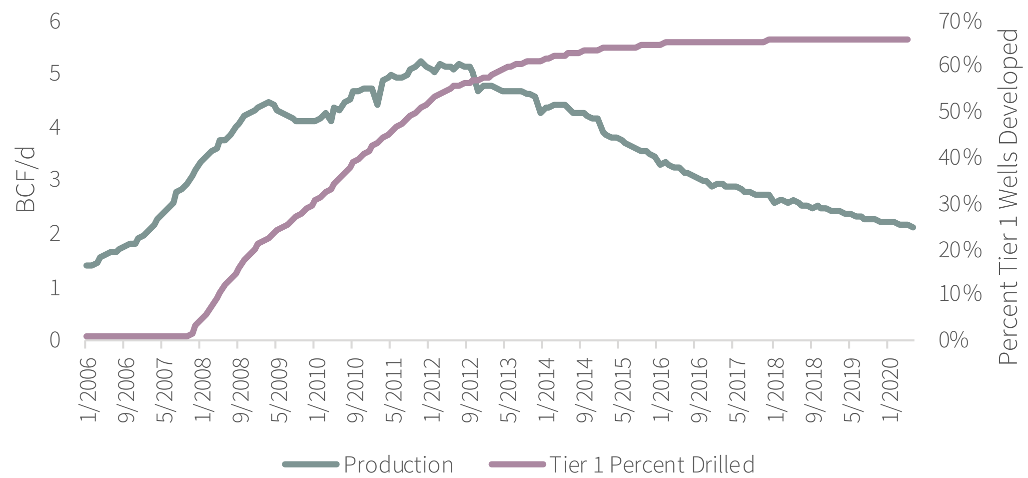


Thick line represents basin boundary. Thin line represents Core Area. Dotted Line represents Best Tier 1.

Source: G&R Neural Network

Our neural network suggests that by 2012, nearly 60% of all the best Tier 1 locations in the Barnett had already been drilled. It now seems that this 60% Tier 1 development threshold coincides with a stagnation in overall drilling productivity Once 40% of the best wells are drilled drilling productivity plateaus and begins to slow and once 60% of the best wells have been developed overall production begins to fall.

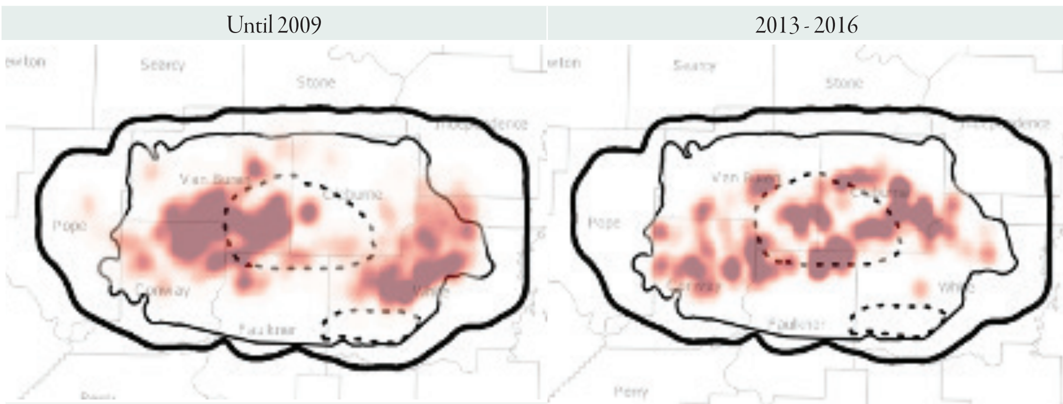
FIGURE 6 Barnett



Source: G&R Neural Network

The same phenomenon occurred in the Fayetteville shale as well. This map shows all the Fayetteville wells drilled through 2009 along with our neural network's estimates of Tier 1 locations. On the right is the same map with wells drilled in 2013. Although it is less pronounced than the Barnett, the drillers had focused in our the best part of the cores here as well.

FIGURE 7 Fayetteville Drilling Intensity by Area

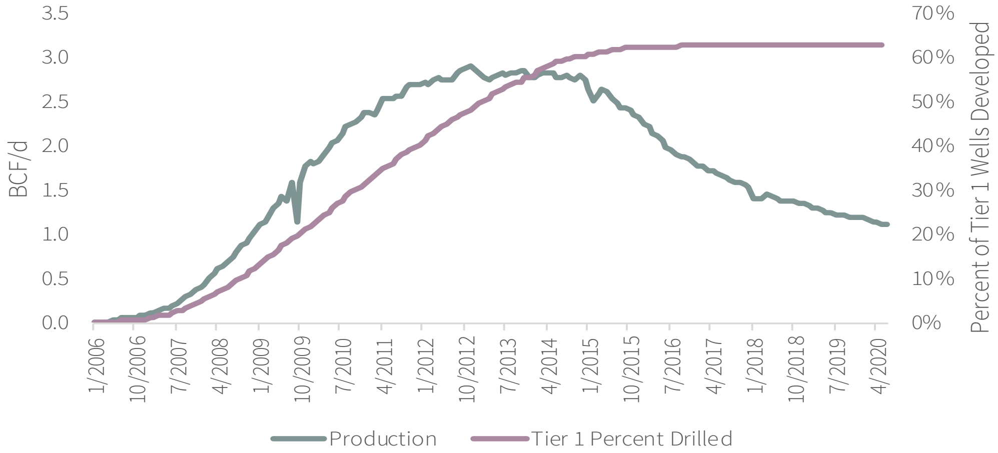


Thick line represents basin boundary. Thin line represents Core Area. Dotted Line represents Best Tier 1.

Source: G&R Neural Network

As you can see, producers zeroed in on the best Tier 1 areas of the Fayetteville, just like in the Barnett, and production plateaued once 40% of the Tier 1 wells were developed and declined once 60% had been drilled.

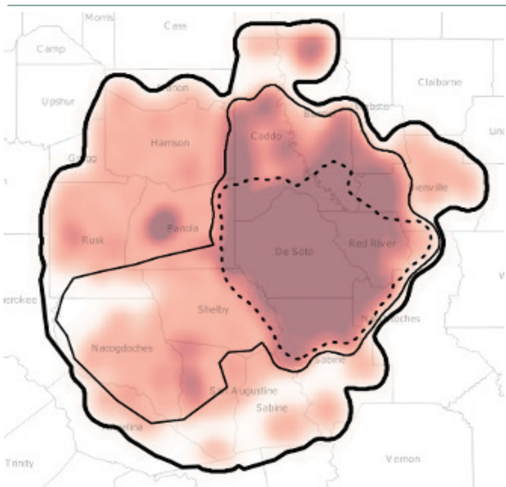
FIGURE 8 Fayetteville



Source: G&R Neural Network

The two main sources of recent growth have been the Marcellus and Haynesville, but our models tell us they are going through the same phenomenon. The following maps show how concentrated drilling has become in the best areas of both basins in 2018 and 2019. We estimate that over the last five years, Marcellus producers have concentrated their drilling in Tier 1 areas from 45% of all wells to 60%. In the Haynesville drillers have gone from 53% to 67%.

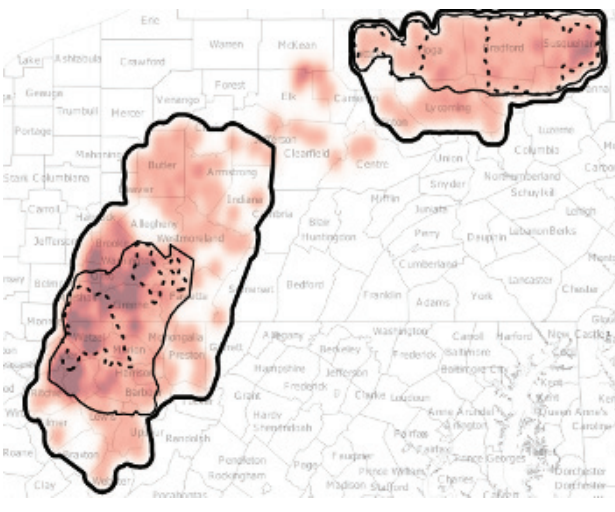
FIGURE 9 Total Haynesville Drilling



Thick line represents basin boundary. Thin line represents Core Area. Dotted Line represents Best Tier 1.

Source: G&R Neural Network

FIGURE 10 Total Marcellus Drilling

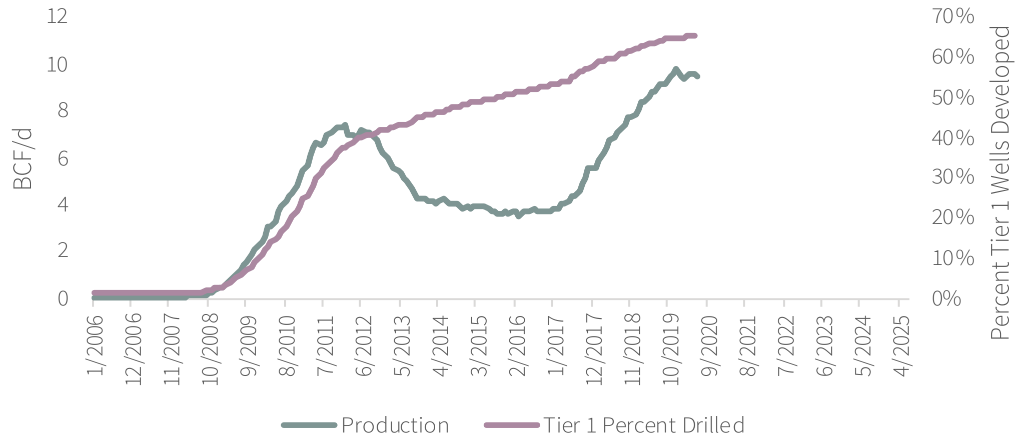


Thick line represents basin boundary. Thin line represents Core Area. Dotted Line represents Best Tier 1.

Source: G&R Neural Network

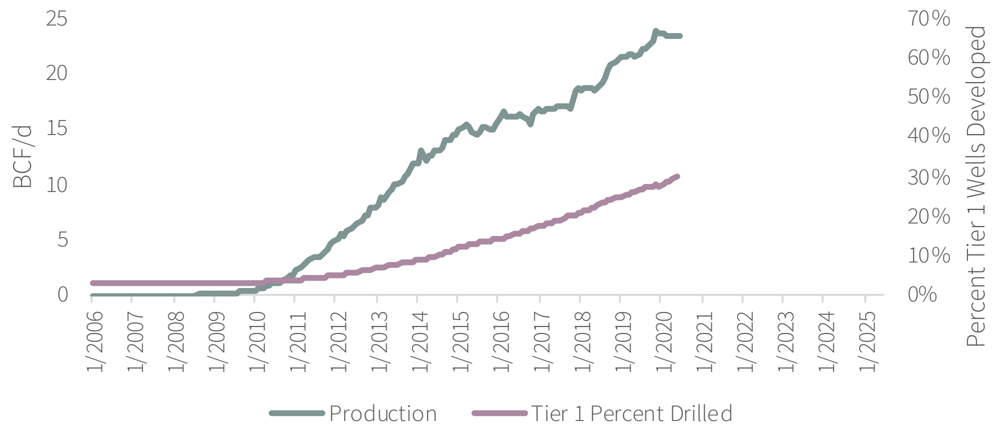
Our neural networks suggests that 60% of Tier 1 wells have been developed in the Haynesville and 40% have been developed in the Marcellus. If these plays follow the same path as the Barnett and Fayetteville, then the Haynesville has entered terminal decline while the Marcellus is in the process of plateauing. Since the end of 2019, gas production from the Marcellus has declined by almost 1 bcf per day while Haynesville production has declined by 400 mmcf/day.

FIGURE 11 Haynesville



Source: G&R Neural Network

FIGURE 12 Marcellus



Source: G&R Neural Network

The only other field that is likely to continue growing over the next several years is the Utica in eastern Ohio and western Pennsylvania. The Utica was developed much later than any other play: production did not start growing materially until 2014. Using the most recent drilling data, our neural network estimates that only 22% of its Tier 1 locations have been drilled to date. Given that significant Tier 1 inventory remains, our models suggest production could still rise by 50% over the next several years.

In our 3Q2019 letter, we also established the relationship between total recoverable reserves and peak production. We showed how a shale gas field's peak production has occurred once half of its total recoverable reserves have been produced. This relationship is very well established in conventional basins, but we showed how it held true with the Barnett and Fayetteville as well. According to this our analysis, the Haynesville has likely produced more than half its total reserves and as a result has likely peaked. The Marcellus is not far behind. The Utica once again is the only basin that shows signs of potential growth.

Production of associated gas from the shale oil fields will be challenged as well. Please see our oil section for an in-depth discussion of the challenges going forward. In the short term, associated gas is almost guaranteed to decline as drilling in the Permian has fallen by 70% in only three months.

In total, we believe that shale production will decline by 1.5 bdf/d per year over the next five years after having averaged an incredibly 4 bcf/d of growth each year over the past decade.

We have long argued that gas fundamentals have been weak because of surging supply. Demand has actually been very robust and we believe will continue to be going forward. The key issue is supply which is finally in the process of rolling over and entering a period of sustained declines. If we are correct, then we are on the verge of a new bull market in North American natural gas.

US Natural Gas Demand by Source

	2005		2019		Change	
	BCF/D	% Total	BCF/D	% Total	BCF/D	% Increase
Lease & Plant	3.1	5.0%	5.1	5.2%	2.0	64.5%
Pipeline Compression	1.6	2.6%	2.4	2.4%	0.8	50.0%
Residential	13.2	21.3%	13.7	13.8%	0.5	3.8%
Commercial	8.2	13.2%	9.7	9.8%	1.5	18.3%
Industrial	18.1	29.2%	22.9	23.1%	4.8	26.5%
Electricity Generation	16.1	26.0%	31.0	31.3%	14.9	92.5%
Total Domestic Consumption	60.3	97.4%	84.8	85.7%	24.5	40.6%
Pipeline exports to Canada	1.0	1.6%	2.7	2.7%	1.7	170.0%
Pipeline exports to Mexico	0.8	1.3%	5.1	5.2%	4.3	537.5%
LNG Exports	--	0.0%	5.1	5.2%	5.1	N/A
Storage Demand	(0.2)	-0.3%	1.3	1.3%	1.5	N/A
Total Demand	61.9	100.0%	99.0	100.0%	37.1	59.9%

Over the last three months there has been some concern around weak demand and rising inventory levels. Weather in the early summer months was milder than historical averages which dampened cooling demand. At the same time, export demand for US LNG, fell from an all-time high of almost 10 bcf/d in March to only 4 bcf /d because of coronavirus related dislocations. As a result, US inventories ended July at 3.2 tcf – 15% above seasonal averages. Nevertheless, we estimate that if weather is normal from here through the end of the cooling season in October and LNG demand continues its path to normalization, inventories could end near average levels. Barring a much milder-than-average winter, we expect inventories to dip well below seasonal averages going into 2021. In our next letter, we will discuss the demand components for US natural gas and what prices will be needed to squeeze this demand from the system as supply continues to contract.

We will be watching this sector closely, but believe we have now entered into a new sustained bull market that will see natural gas move back towards its energy equivalency with oil. Remember, if oil returns to $75 per barrel, even an oil-to-gas ratio of 10 yields a $7.50 mcf gas price, over four times higher than today.

Q2 2020 Natural Resource Market Commentary

Most commodities and their related equities bottomed at the end of the first quarter in a spasm of panic selling and then staged strong rallies. The S&P 500 also bottomed in the last week in March before advancing a strong 20% in the second quarter. Given their significant underperformance in the first quarter, natural resource stocks enjoyed a strong rebound. The S&P North American Natural Resource Stock Index (heavily weighted to large cap energy equities) rose almost 28% while the S&P Global Natural Resource Index (which has more mining and agriculture exposure) rose 20% -- in line with the broad market.

Oil had by far its most volatile quarter ever. After starting at a little over $20 per barrel, oil drifted lower over the next 20 days before crashing on April 20th -- the day before the May WTI crude oil futures expired. After the May contract expired at -$37 per barrel (a negative price caused by insufficient storage capability by NYMEX futures participants), oil proceeded to regain all its lost ground, finishing the month exactly where it started at $20 per barrel. Oil's rally continued into May and June with oil ultimately advancing by 90% for the quarter. The Brent futures contract, which mandates cash settlement as opposed to the requirement that WTI contracts be physically settled, experienced far less volatility. It started the quarter at $23 per barrel, fell to only $19 per barrel and finished at $41 per barrel, up 78%.

Oil related equities also rallied significantly. The S&P E&P index (as measured by the XOP ETF), rallied a strong 60% while oil service stocks (as measured by the VanEck Oil Service Index) rose 50%. Large cap energy names, pipelines, and refiners (as measured by the XLE ETF) rose 35%.

"IN PREVIOUS LETTERS WE EXPLAINED OUR SWITCH FROM NATURAL GAS BEARS TO BULLS BASED ON OUR ANALYSIS THAT THE RELENTLESS GROWTH IN US NATURAL GAS SUPPLY WAS COMING TO AN END."

The energy price rebound surprised most investors. First, oil demand did not collapse nearly as much as projected by agencies like the IEA. Original projections for second quarter demand estimated collapses of anywhere between 25 to 30 mm barrel per day. Now that the data is in, it looks like demand only the collapsed by less than half these original projections. One of the chronic mistakes oil market analysts have made over the last 15 years is to severely underestimate oil demand in the non-OECD world. Although oil demand in the OECD world did experience severe weakness (although not as bad as predicted), it looks as though non-OECD oil demand fell far less. Second, supply cutbacks from OPEC combined with collapsing non-OPEC oil supply, left production falling much faster than anyone thought.

Stronger than expected demand coupled with very weak supply resulted in three extremely important consequences. First, it now looks like we were not as close to filling global storage as originally feared. Even on the day when the May WTI futures contract expired, there was plenty of storage available at the Cushing settlement point. The dislocation was the result of those parties that controlled the storage and who, in a panic, chose not to lease it out. Second, global inventories have already begun to draw – much sooner than anyone thought possible. Third, it now looks like global oil inventories peaked at levels far below the worst case projections made just three months ago. In fact, global oil inventories likely did not even hit the levels reached at their last peak in the first quarter of 2016.

Although everyone remains incredibly bearish on oil prices, we believe that 2021 will experience a series of oil price shocks. Even with all the OPEC+ cuts being reversed, global oil markets now have structural deficits embedded for the foreseeable future. Oil prices will have to rise significantly over the next several years for this structural gap to be closed. The energy component of the S&P 500 hit 2.5% in the second quarter from a high of almost 35% back in 1980 and now stands at the lowest reading ever. Investors hardly have any exposure to energy; a group with all the fundamental characteristics to make it one of the best performing asset classes of this upcoming decade.

Natural gas prices rose almost 7%. In previous letters we explained our switch from natural gas bears to bulls based on our analysis that the relentless growth in US natural gas supply was coming to an end. US natural gas supply indeed peaked last December at 96 bcf per day and in just five months has fallen by 8.4 bcf per day. US gas supply did grow an incredible 12% in 2018 and 10% in 2019, led by continued growth in the Marcellus and surging production in the Permian, but those huge production gains are done. US gas production is now down year-on-year by 2.4 bcf/d – the largest contraction in four years.

The recent weakness in natural gas production can be partially attributed to weakness in the gas rig count. After peaking at 200 gas-directed rigs in the first quarter of 2019, the rig count has collapsed to only 71. There are other longer-term bullish trends that are emerging in North American natural gas supply as well. Nearly half of US natural gas supply now comes from three fields: the Marcellus (25%), the Haynesville (10%) and associated gas from the Permian (10%).

Since 2010, these three fields have increased production by 37 bcf per day, representing well over 100% of US supply growth. Our analysis tells us that all three of these fields are on the verge of decline. Since the shale revolution, US natural gas production has nearly doubled, but we think going forward the gas supply will begin to shrink. Future growth will be extremely difficult unless gas prices move much higher. We recommend a significant weighting to natural gas equities, which have been terrible performers over the last decade, and offer great value.

Turning to precious metals, gold advanced 13% and silver rebounded a strong 34% in the second quarter. Platinum advanced 13% and palladium fell 18%. For the year to date, gold is now up almost 26% while silver has regained all its first quarter losses and is up 3%; platinum is down 14% and palladium is flat. Reflecting the strength in the metals, both gold and silver equites surged. Gold stocks (as measured by the GDX ETF) rose almost 60% and silver stocks (as measured by the SIL ETF), rose 56%. For the year, gold stocks are rivalling the performance of the FANG and large cap tech technology sectors of the markets.

As of July 31st, 2020, gold has surpassed $1,950 per ounce and has established several new all-time daily highs. The previous high occurred on September 5, 2011. Although the gold price today is exactly where it was 9 years ago, the financial world has completely changed.

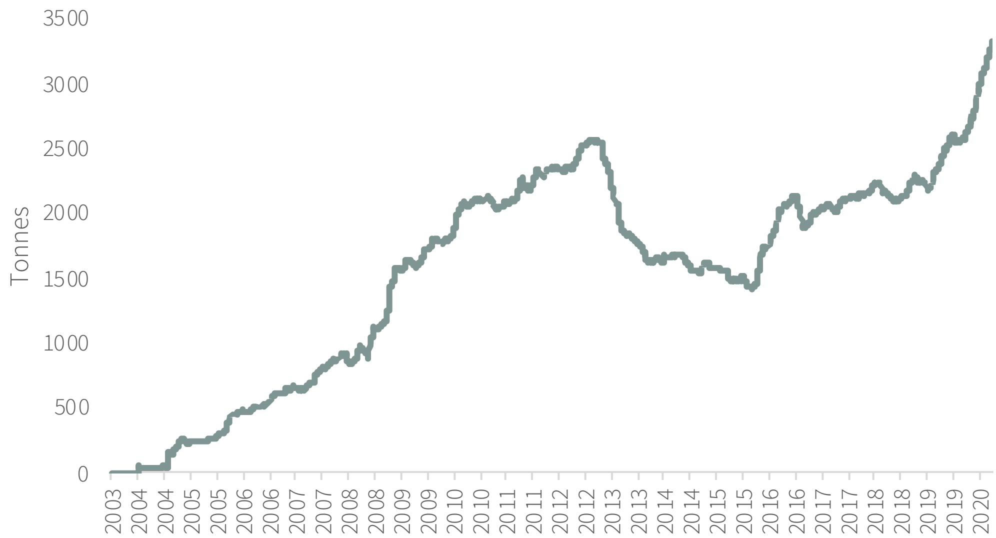
Over that time, the Fed's balance sheet has advanced 137% to total nearly $7 tr. The European Central Bank's (ECB) balance sheet has grown 145% to reach E4.6 tr. The Japan Central Bank's (JCB) balance sheet growth leads the pack, having advanced 365% to reach 640 trillion yen.

There is an historical relationship between the size of a central bank's balance sheet and the price of gold going back to the Federal Reserve's establishment in 1913. Even adjusting the Fed's balance sheet for excess reserves (a debate in and of itself), we believe today's balance sheet justifies a gold price in excess of $15,000 per ounce on the low side or $25,000 per ounce on the high end. For a complete discussion of the relationship between the size of the Fed's balance sheet and the price of gold, please consult our 2Q2018 letter.

We have written how the current gold bull market will be driven by Western investors, compared with its first leg which started in 1999 and ended in September 2011and was dominated by Eastern buyers, particularly from India and China. We also explained how the upcoming bull market would have a huge speculative element to it – again quite different from the first leg of the bull market that was mostly orderly and driven by value-conscious Eastern investors.

The second quarter provided more evidence the Western buyer has returned. Accumulation of metal through the physical gold and silver ETFs (a proxy for Western buying) continues to surge. For the first quarter of 2020, the 17 physical gold ETFs we follow accumulated 228 tonnes and this continued into the second quarter.

FIGURE 13 ETF Gold Holdings



Source: Bloomberg

Second quarter gold ETF accumulation totaled 395 tonnes. Through the first three weeks of July, they have added another 120 tonnes. Year to date, gold ETFs have accumulated over 730 tonnes, already more than doubling the 360 tonnes accumulated in 2019. Given that gold continues to gain both momentum and investment popularity, strong Western gold support should continue.

After trading sideways for the last four years, silver finally broke out of its trading range over the last few weeks. Just like the gold ETFs, the seven physical silver ETFs we follow saw a surge in accumulation. Year to date, the ETFs have added 7,842 tonnes of silver – more than three times the 2,573 tonnes accumulated in 2019.

The breakout in silver, is further conformation the bull market in gold is now well underway. Although we continue to prefer oil and oil related investments to gold here, (please see our essay: "The Gold-Oil Ratio Revisited" in our 1Q2020 letter), we continue to think precious metals have entered into a large sustained bull market. If we see a significant pullback in precious metals — for example if a COVID-19 vaccine is introduced -- we would use the weakness to add further to our investments. Precious metals have entered into a huge bull market that will eventually take gold significantly past $10,000 per ounce later this decade.

Base metal prices also recovered in the second quarter: copper by almost 22%, nickel by 12% zinc by 8%, and aluminum by 6%. Copper equities also rebounded sharply during the quarter. The COPX (Global X Copper Miners EFT) rose a strong 50% during the quarter. Base metal equities, as measured by the XBM (the TSX Global Base Metal Index ETF), rose 38%.

Copper remains our favorite metal because its underlying fundamentals remain the best in the base metal complex. Reflecting the positive supply and demand fundamentals, copper prices today have retraced all their losses experienced in the first quarter and are up 3% for the year. Nickel and zinc prices remain down 4% and aluminum prices are down 7%. Copper equities have also recovered all their losses, and today are flat for the year, whereas most base metal equities, as measured by the XBM ETF, are down 7%.

According to World Bureau of Metal Statistics (WBMS), global copper markets have turned into steep deficit. On the supply side, total mine supply for the first five months of 2020 is now down about 1% versus 2019. The only significant supply additions for 2020 occurred in China which mined 175 more tonnes of copper in the first five months in 2020 versus 2019. Outside of China, it now looks as if total world mine supply has been impacted by about 3% by COVID-19 related shutdowns.

The real shock has come on the demand side. As we mentioned in our last letter, stories of extremely strong copper demand coming from China kept circulating and strong copper scrap metal prices confirmed that China demand was rebounding strongly. This is now confirmed by the WBMS data which shows, for the first five months of 2020, total Chinese copper demand surged 10% so far this year versus last year. Outside of China, it looks like total world demand has now fallen modestly.

Copper exchange inventory levels confirm the emerging deficit in the global copper market. Combined copper warehouse inventories of the London Metal Exchange, Shanghai, and COMEX peaked at 680 mm tonnes at the end of March and now stand at 380 mm tonnes, a drop of 250 tonnes. The inventory build we saw in the first three months of 2020 has now been completely reversed and exchange listed inventories have retreated to pre-COVID-19 levels.

Continued strong Chinese demand, the emergence of strong Indian demand, and the copper intensity needed to make renewable electricity from wind and solar sources give copper the best demand profile of any base metal.

On the supply side, we believe copper will achieve little in the way of mine supply growth in the next five years. On July 2 2020, Rio Tinto Group, the operator of the Oyu Tolgoi mine which is projected to produce 500,000 tonnes of copper annually, announced full production has now been pushed out until at least 2022 and future development costs are expected to be $1.3 to $1.8 billion greater than original estimates. Other than the ramp up in production from First Quantum's new Cobre Panama mine, taking place right now, Oyu Tolgoi is one of only two new large mines scheduled to come on line between now and 2025. We visited the Oyu Tolgoi mine site back in 2002 and again in 2010 once extensive underground development had already taken place. We have said before that future production delays were probable as underground mining conditions will remain extremely challenging since they have developed part of the mine in unstable rock conditions (i.e., a fault zone).

In addition to the problems at Oyu Tolgoi, future copper mine disappointment is developing at the world's largest copper producer, Codelco. Because of low copper prices and COVID-19 related concerns, Codelco has suspended project development at both its Chuquicamata underground mine development and its largest mine, El Teniente. These two structural projects were set to contribute more than half of Codelco's output by the end of this decade. Without completion of these two projects, Coldelco's production should begin to see sustained declines starting as early as 2022 and could offset any positive production gain coming from the start of the high-grade Kamoa-Kakula project in the Democratic Republic of Congo which is slated to ramp up production in 2022.

We recommend investors maintain significant exposure to copper related equities.

Agricultural markets remained quiet during the second quarter. Corn fell 5% while soybean rose 1% and wheat fell 13%. Year to date, corn is now down 13% while soybeans are down 6%, and wheat is down 12%. Grain investors seemed to shrug off several bullish announcements during the quarter. On June 30th, the USDA announced that farmers had only planted 92 mm acres of corn this year, far below planting expectations of 97 mm acres. Earlier this year, because of weak feed demand and a severe drop in ethanol consumption, the USDA had boosted its estimates of 2020-21 corn ending stocks to 3.3 bn bushels – the highest level since 1987-88. This estimate had been based on planted acres rising by 7.3 mm acres compared with last year.

Due to much lower than expected planted acres, the USDA reduced its estimates for corn production by 1 bn bushels in their June 30th report. This was offset by a further downward revision to corn demand by 325 mm bushels. Taken together, the USDA reduced their carryout to 2.6 bn bushels, some 350 mm bushels above the four-year average but much lower than originally expected. Although inventories are expected to remain high, the 2020 planting report puts corn in a much less bearish position. Soybean planting and carryout estimates were little changed since last quarter.

The other big corn announcement took place on July 10th, when the US announced that China had purchased 1.7 mm tonnes of corn. This purchase followed a 686 mm tonne purchase in May.

Although the press attributed the sale of US corn to China as a fulfillment of "Stage 1" of the China-US trade accord, we will carefully monitor China's actions in the future. Back in our second quarter 2018 letter we wrote: "Given the large drawdown now taking place in Chinese corn inventories, we believe China will be forced to become a large corn importer in the next several years." China's domestic corn consumption reached 275 mm tonnes while production is estimated to be only 250 mm tonnes, leaving a gap of almost 25 mm tonnes. Over the last several years any such gaps have been filled through government sales.

In 2018, we estimated that Chinese corn inventories were between 80 and 140 mm tonnes. If these number are anywhere near correct (which we cannot say for certain), the overhang of China's large corn inventories might be drawing to a close.

China has been almost completely absent as an international corn buyer since 2015 when they began to liquidate their internal inventories. Could recent purchases signal their re-entry into global seaborne markets? If China became an importer once again, it would add significant upward pressure to corn prices.

With the 2020 crop now fully planted in North America, the focus turns to weather and its impact on crop condition and yields. So far, growing conditions across most of the US remain extremely good. We believe that global weather conditions will be become much more challenging as the decade unfolds and we enter another period of low sunspot activity (please see our 1Q2019 letter). We remain bullish on grain prices. Extremely strong grain demand (driven by increased protein consumption in the emerging market world) coupled with weather-related yield disappointments lead us to maintain our investments in agricultural equities.

"ITS CULT STATUS AMONG INVESTORS WAS RIVALED ONLY BY RADIO CORPORATION OF AMERICA DURING THE 1920S."

Uranium was strong during the second quarter and continues to be a bright spot in global commodity markets. After a strong first quarter, spot uranium rallied by 20% in the second quarter. Year to date, uranium is up 32% on a spot basis. Uranium equities performed even better, advancing between 20 and 35% in the second quarter after a weak first quarter. Year to date, bellwether uranium equities have rallied between 7-15%. There were no major fundamental developments in uranium markets during the quarter. Instead, we believe the strong performance comes from the longer-term supply and demand fundamentals we have outlined in past letters.

The coronavirus has had limited impact on uranium demand so far this year, given how difficult it is to ramp down nuclear power facilities. Ideally, a nuclear plant operates at a very steady dispatch rate. This characteristic makes it ideal for baseload power generation and means it should be the last source of power to be scaled up or down during periods of dislocations. It is far easier to reduce electricity production from a natural gas fired plant than from a nuclear facility and that has helped uranium's demand profile during the acute phases of the lockdowns. However, the coronavirus continues to severely impact uranium supply. In February, Cameco announced it would close its remaining flagship mine at Cigar Lake due to concerns around COVID-19. The operation is the world's highest-grade uranium mine and was expected to produce 18 million pounds of uranium in 2020, or 12% of global mine supply. While most analysts expected the shutdown to last several weeks at most, Cameco has just announced that production will not resume before September at the earliest. Long term fuel buyers have been playing a dangerous game with producers, waiting to renew expiring contracts on the hopes of lower prices. Now that uranium prices have moved materially higher for a full twelve months, and Cameco continues to shutter both its flagship mines, many fuel buyers are likely feeling pressure to renew contracts or risk supply interruptions. We expect this will lead to much higher contract prices which in turn will help support the uranium rally.

The 40-Year Odyssey of Schlumberger

The FANG stocks are today's investment craze. For comparison's sake, consider Schlumberger's odyssey from 1962-1980. From its initial public offering on the NYSE in 1962 to its peak in 1980, Schlumberger appreciated 50-fold. Its cult status among investors was rivaled only by Radio Corporation of America during the 1920s. Adding to its mystique, Schlumberger was the only member of the Nifty Fifty growth stock craze of the late 1960s and early 1970s to emerge unscathed from the 1974-75 bear market. Unlike its peers, Schlumberger actually emerged from the carnage some five times higher. An investor that bought Schlumberger at its average price in 1962 enjoyed a 25% compounded return over the next eighteen years. Instead of slowing, by the end of the 1970s, Schlumberger's revenue and earning's growth were accelerating. An investor who bought the stock in 1971 compounded their money at 37% over the next nine years. An investor in the Dow Jones Industrial Average, by comparison, experienced a compounded return of only 3%.On a split-adjusted basis, Schlumberger peaked in 1980 at $19.73; forty years later (2020), the stock ended the second quarter at $18.39. The Dow Jones has rallied from 900 to 26,000 over the same period.

Market lore maintains that Schlumberger became the largest company in the world based on market capitalization in 1980, but this is not true. With nearly 191 mm shares outstanding, its $25 bn of market capitalization placed it fourth behind AT&T (pre-breakup), IBM, and Exxon, each worth approximately $40 bn.

What was impressive was Schlumberger's capitalization when adjusted for the size of its asset base. AT&T's book value was $125 bn while Exxon and IBM had $50 and $30 bn of book value, respectively. Schlumberger, on the other hand, was almost tiny. It had only $5 bn of invested capital – between six and thirty times less than its closest market capitalization rivals.

"ITS NEARLY 60-YEAR HISTORY AS A PUBLIC COMPANY ON THE NYSE IS AN ODYSSEY OF BOOMS AND BUSTS, BULL AND BEAR MARKETS, AND THE IMPACTS OF INFLATION AND DEFLATION."

The company provided the most advanced exploration, drilling, and production services to a global oil and gas industry that was rapidly expanding. Oil prices had started the decade at $3.50 per barrel and by 1980 had rallied more than ten-fold to surpass $35. Oil and gas producers found themselves awash in cash that needed to be reinvested.

Investors believed the world's oil supply faced continued disruptions and production disappointments. Prices were high and were expected to move much higher. Energy company budgets exploded in response to ever-rising oil prices and this explosion in upstream capital spending directly lifted Schlumberger's top and bottom line. Between 1970 and 1980, Schlumberger compounded its revenues by 28% per annum while its earnings grew by 36% annually. I began my investment career in the early 1980s in the trust department of a prominent Wall Street bank and vividly recall how nearly every trust and investment account held the stock.

Given its popularity, it is not surprising that Schlumberger sported an expensive valuation. At its peak in late 1980, Schlumberger was priced at 25 times its earnings and nearly eight times its book value, while its enterprise value was five times its sales. Although these multiples seem quaint to those without gray hair, it is important to realize how cheap the rest of the market was in 1980. With the Dow Jones Industrial average at 900, the market was priced at par with its book value and only seven times its earnings. Its dividend yield was over 6%.

Today the market trades at over four times its book value and over 30 times its earnings. (Please see the February 7, 2020 issue of *Grant's Interest Rate Observer* for an interesting discussion of the true P/E of today's market.) The Dow yields just 1.7%. Schlumberger was the fourth largest company in 1980 with a market capitalization of $25 bn. Today's fourth largest company is Google, which sports a $1 tr valuation – forty times greater than Schlumberger in 1980.

Founded in 1926, Schlumberger did not make its debut on the New York Stock exchange until 1962. Its nearly 60-year history as a public company on the NYSE is an odyssey of booms and busts, bull and bear markets, and the impacts of inflation and deflation. Most important, it is a story of market psychology, a study of how an investment belief can become universally accepted, the related stocks can become "must own," and their valuations can become radically stretched. Then something strange almost inevitably happens. Unexpected shifts in the economic and business landscape emerge and gather strength. The universally accepted investment belief is then completely undermined. The result: stock prices and valuations collapse.

As compared to today, the economic and financial backdrop in 1980 could not be more different. Inflation had become an intractable problem, commodities were in short supply, oil was running out, and precious metals were by far the most popular asset class. Well-known business magazines were calling for the death of equities, arguing that financial assets would never again offer strong returns. Stocks and bonds were extremely unpopular asset classes. The only exceptions were those companies that could realize pricing power from the underlying inflation. Enter commodity stocks. Of the 10 largest companies by market capitalization in 1980, six were oil stocks. In total, one third of the S&P 500's market value was energy related and Schlumberger was the most popular of the bunch.

Just when investors became universally convinced that oil prices could only move higher, exactly the opposite happened. The bull market of the 1970s spurred a massive upstream investment boom and supply surged. Instead of running out of oil, the world was on the verge of developing the largest new fields in a generation. Oil prices peaked in the first quarter of 1981 and entered a grinding bear market that would last 20 years.

Although Schlumberger again became a market leader during the energy bull market of last decade, it never regained the ground it lost on a relative basis. For example, the stock reached an all-time high of $118 in the summer of 2014 with oil prices at $110 per barrel. Investors who had bought the stock at the peak back in 1980 had finally gotten their money back and then some, but the return was far less than the broad market. An investment in Schlumberger between 1980 and 2014 rose 10-fold compared with 47-fold for the Dow.

We believe today's investment landscape represents the mirror image of what occurred forty years ago. Stocks and bonds are both extremely popular asset classes. Bonds are so popular that $15 trillion of sovereign issues trade with negative yields – a first in 4,000 years of financial history. Instead of worrying about inflation, most investors are convinced deflation is here to stay.

When interest rates peaked in the summer of 1980, 10-year US Treasury bonds were priced to yield 16% and energy stocks made up one third of the S&P 500 – both record highs. Today, 10-year US Treasury bonds are priced to yield 0.66% and energy stocks make up 2.5% of the S&P 500 – both record lows.

In 1980, Schlumberger traded at eight times book value and 25 times earnings compared with the broad market that traded at book value and seven times earnings. Today, the broad market trades at four times book value and 30 times earnings. Schlumberger, on the other hand, got as low as $12.50 during the depths of the first quarter. Even after its $21 bn of COVID-19 related write-offs, Schlumberger still only traded at book value and eight times trailing operating earnings. In the 50 years of operational and valuation data we keep on hand for Schlumberger, these are the cheapest levels ever reached.

Today, Schlumberger's share price trades below where it traded four decades ago while the broad market now trade thirty times higher. Investors today are concerned about runaway deflation and, instead of worrying about peak oil supply, they are worried about peak oil demand. Many investors believe energy stocks cannot be owned at any price with many arguing for "negative" values given ESG concerns and contingent liabilities (if bond yields can trade negative and oil prices can trade negative perhaps common equity can as well?).

The investment landscape has completely flipped in forty years. This is true of inflationary expectations, bond yields, energy prices, commodity stock valuations, and broad equity prices. Four technology companies each sport a market capitalization greater than $1 tr and $14 tr of fixed income securities trade with negative yields. You can certainly argue that both stocks and bonds have never been more popular.

Few investors saw the seismic shift about to take place in 1980 and even fewer were positioned accordingly. We have argued for some time now that another unforeseen reversal is imminent. The fundamental events that undid Schlumberger's meteoric success four decades ago is about to be repeated but this time in reverse. The prevailing wisdom that helped push stocks like Amazon to 20 times book value and 125 times earnings will somehow fail to come to fruition. Similarly, the near-universal bearishness that grips energy names like Schlumberger will end up being false.

A massive reversal in investment capital flows is about to take place. Back in 1980 no one could possibly envision that Schlumberger would ever trade below its 1980 price in the years to come—but 40 years later it does. The FANG stocks today are in the same position as Schlumberger in 1980. History is about to repeat itself and few investors are positioned to profit from it.