What is Happening to the U.S. Shale Production?

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What's happening to US shale production? After growing by a torrid 145,000 b/d per month in 2018, shale production growth has ground to a screeching halt. Since December, shale oil production has grown by only 50,000 b/d per month–a collapse of almost 65% versus 2018's phenomenal rates. Despite this slowdown, most energy analysts are still hoping for strong shale production growth both this year and next. For example, Rystad Energy, the Norwegian-based energy consulting firm, still believes total US liquids production will surge by another 1.8 mm b/d in 2020. However, our research suggests these optimistic projections will be difficult if not impossible to achieve.

In past letters, we defined what we believe are the factors that drove improved shale productivity growth over the last five years, and we explained why robust US shale oil production growth of the past decade was rapidly nearing an inflection point. Conventional wisdom held that productivity gains were the result of operators drilling and completing larger and better wells (longer laterals, larger proppant loadings, and greater fluid volumes). However, our research pointed us in an entirely different direction. We believe the surge in drilling productivity over the last five years is largely the result of where operators drilled them. In particular, we believe the improved drilling productivity was the result of a practice known as "high-grading." High-grading is an age-old practice used in both the oil and gas industry as well as the mining industry which simply consists of selecting and drilling your most productive prospects first. Over the last five years, the E&P industry has shifted significantly away from drilling their less productive Tier 2 acreage in favor of drilling their more productive Tier 1 acreage. Since drilling a Tier 1 well is nearly 100% more productive than a Tier 2 well, the industry has created the illusion of ever-improving productivity growth by narrowing their focus to only their best prospects. If our research is correct, then future increases in shale drilling productivity will be more a function of continued "high-grading" and less a function of ever-changing drilling and completion techniques.

In our last letter, we detailed the proprietary artificial neural network we built to analyze the acreage quality of the US shales. We concluded that both the Eagle Ford and Bakken shales were quickly running out of Tier 1 acreage and that production growth from these plays was set to significantly disappoint in the coming years. We also concluded that while the Permian basin had more remaining Tier 1 inventory than the other two, it would also begin to experience the first signs of exhaustion sooner than most people expected. Now that the US shales have started slowing dramatically, we have turned to our artificial neural network to help shed light on the reasons why.

Our neural network has accomplished two things. First, we were able to pinpoint the factors leading to this year's dramatic slowdown and second, we can see these same factors will only become more severe in the next several years. For the first eight months of 2019 shale production grew by 57,000 b/d per month on average. This represented a slow-down of 60% compared with the eight months ending August 2018, during which production grew by 132,000 b/d per month on average. Remarkably, this slowdown occurred even though the industry completed 10% more wells during the first eight months of 2019 than in the same period last year. In aggregate, production from all new wells actually accelerated between the two periods--from 571,000 b/d per month to 640,000 b/d per month due mainly to the higher number of wells completed. However, drilling productivity, although still growing slightly, has now slowed dramatically. For the eight months ending August 2018, a new well flowed 460 barrels of oil on average during its first full month of production compared with 470 barrels this year—a rise of only 2% and a dramatic slowdown from the 10% drilling productivity growth experienced in the first eight months of 2018 versus the first eight months of 2017.

Also strongly contributing to the slowdown has been the dramatic increase in the underlying base declines. For the eight-month period ending August 2018, production from existing wells declined by 440,000 b/d per month on average. By August 2019, this figure had accelerated to 590,000 b/d per month – an increase of 150,000 b/d. The acceleration in the base decline overwhelmed all other factors and net production growth ground to a halt. Two factors explain the acceleration in base declines: a larger production base and a higher decline rate. Total production increased by 20% between the two periods. Therefore, even with a constant decline rate, the total barrels of depletion would have increased materially. However, base decline rates accelerated from 54% annualized for the eight months ending August 2018 to 58% by August 2019. The reason: new wells have much higher declines than old wells and the surge in new wells drilled and completed in 2018 significantly increased the overall decline rate in the production base.

We also considered another interesting comparative period: the eight months ending July 2017. This period marked the last time average monthly production growth was comparable to today (50 k b/d per month). Remarkably, two years ago the oil industry turned 650 rigs to reach this level of growth whereas 810 rigs are required today. Furthermore, drilling times have collapsed over the last two years resulting in more completions per well operating. In total, we estimate that nearly 60% more wells were completed in the eight months ending August 2019 than in the period ending July 2017. Moreover, today's average well is 11% more productive than in 2017 (for those that are interested, our neural network predicts this modest productivity boost was a function of both improved drilling techniques and high-grading). The combination of 60% more completions and 11% more productive wells doubled new well production from 370,000 b/d per month in 2017 to 640,000 b/d per month today. While the contribution from new wells increased massively over the last two years so did the base declines. In fact, base declines accelerated by nearly 270,000 b/d between the two periods, offsetting the entire increase in new production. In other words, the shale industry now needs 60% more wells, each of which is 11% more productive, to reach the same level of growth as it did two years ago.

Production growth is set to slow even more now that the oil rig count has fallen materially. After peaking at 890 rigs in November 2018, the rig count has fallen 20% to reach 713 rigs at present with the bulk of this decline occurring in the last four months. There tends to be a two-month lag between rig count and first production and so we believe the impact of this dramatic slowdown will be felt as we progress through Q4. In past shale cycles, a slowing rig count has always been offset by an increase in per-well productivity. The reason is simple: rigs drilling the least productive wells are laid down first. During the 2009 slowdown, the major three shale oil basins (Eagle Ford, Bakken and Permian) lost 60% of their rigs. However, per-well productivity increased by 75% on average. Production from new wells drilled thereby decreased by only 33%--far less than the decline of the rig count itself. In 2013, the three basins lost ~15% of their rigs but drilling productivity increased by 60% allowing production from new wells to actually accelerate by 35% despite a falling rig count. In 2016, the three basins lost 80% of their rigs while productivity increased nearly 200% resulting in production from new wells to slow by half despite losing 80% of all rigs.

Our models tell us something very different is happening this time. While this year's rig slowdown is comparable with the 2013 experience (both 15%), the increase in per-well productivity has been much more muted. Per-well productivity increased by 60% in 2013 while our models suggest the improvement so far this year has been less than 15%. The sample size is fairly small, and the data is preliminary and subject to revision, however we now believe the high-grading effect may be responsible. In 2013, 45% of the wells drilled in the three major shale basins were Tier 1. As operators dropped rigs, they were able to select and drop their worst locations and high-grade their inventory, increasing their per-well productivity in the process. By 2018, operators had high-graded to the point where nearly 70% of all wells were Tier 1. As the rig count comes down this time, our models suggest there will be much less of an opportunity to high-grade compared with 2013. We don't expect the per-well productivity to be able to offset the slowdown, as it did in past cycles.

In our view, the next twelve months will be a critical test of the US oil shales. Our models tell us the remaining inventory of prime Tier 1 drilling locations is much less than widely believed. While many analysts believe the shales are capable of producing a near-limitless volume of crude, we know this is not the case. The shales must now contend with a large base of existing legacy production that relentlessly declines and must be replaced. We have seen how sensitive net shale production growth can be: a slight slowdown in productivity gains combined with a slight uptick in the base decline rate can very quickly take production growth from record rates to near-flat production in a matter of months. None of these pressures show any signs of letting up and now the rig count has started to materially decline. We expect production growth to slow even more from here as a result.

We want to once again emphasize how important the US shales are to global oil balances. We first published exhibit 1 in our Q2 2018 letter. The table in the exhibit clearly shows that conventional non-OPEC oil production outside of the US and Canada has declined by almost 130,000 b/d each year over the past decade. The fact that conventional non-OPEC oil production has rolled over is a huge problem that has received little attention by oil analysts. To put this in perspective, conventional non-OPEC oil production still represents 45% of global oil production and now appears to be in sustained decline. Furthermore, if you include other sources of non-OPEC production, such as Canadian Oil Sands (which is not considered "conventional"), biofuels, refinery gains, and OPEC NGLs (which are not part of the OPEC quota systems), the US shales still represent an enormous 75% of the total non-OPEC liquids growth over the last decade. Now that the Bakken and Eagle Ford are facing exhaustion issues that are readily becoming apparent, nearly all of non-OPEC's production growth will have to come from just one play in West Texas– the Permian. Never before has the global oil industry been so dependent on one field in such a concentrated geographic area for all of its future growth. What happens in the dozen counties that make up the Permian will make or break the global oil market over the next 10 years.

Global oil demand has surged by over 13 mm b/d over the last eight years alone. As a result, even with the surge in US shale oil production OPEC has needed to add nearly 3 mm b/d of new supply to keep the market balanced. With conventional production growth turning negative outside of the US and Canada, it is easy to see how dependent the world has become on the growth of the US shales in general, and the Permian basin in particular. Any faltering in shale production growth should result in a rapid market tightening. In this situation, robust oil demand will need to be rationed by price – a situation not unlike what occurred between 2000 and 2008—a period that eventually saw oil prices exceed $140 per barrel.

	2010	2018	Change
Conventional Oil Production	47.2	45.9	(1.3)
US Oil Shale	0.7	6.5	5.8
US Shale NGL	0.3	2.6	2.3
Canadian Oil Sands	1.5	3.0	1.5
Bio Fuels	1.8	2.6	0.8
Refining Gains	2.1	2.3	0.2
OPEC NGL's	4.4	5.5	1.1
Total Non-OPEC Liquids Production	58.0	68.4	10.4
OPEC Crude Production	29.1	32.2	3.1
Total World Liquids Production	87.1	100.6	13.5
IEA Global Demand Estimates	88.2	99.3	11.1
(+/-) IEA's "Missing Barrels"	(1.0)	1.0	2.0
G&R Demand Estimate	87.2	100.3	13.1

Exhibit 1: Non-OPEC Supply 2010-2018 (Millions of Barrels per Day

Source: IEA, BP, G&R Models.

Notes: Pro-Forma For OPEC Additions Gabon (2016), Equatorial Guinea (2017)

In our last letter, we laid out our projections for shale oil growth for the next several years. We explained how 2019 would likely be the last year the shales grew in excess of 500,000 b/d and that average annual growth over the coming decade would slow 70% from 1 mm b/d in both 2017 and 2018 to 325,000 b/d. We also said that 2019 might actually see fairly robust growth of ~700,000 b/d from January 1 to December 31. In retrospect, we may have been too optimistic. For the first eight months of the year, total shale production grew by only 400,000 b/d and we now expect that January 1 to December 31 growth will likely come in closer to 600,000 b/d or even below. The slowing of shale production growth is occurring as we speak.

In our oil section we will discuss how these dynamics play into the supply and demand balances for the remainder of the year and into 2020. We will also discuss what strategies we are using to take advantage of these developments. The only material source of growth in the non-OPEC world over the past decade is now showing signs of exhaustion and nobody seems to notice. The implications could be tremendous.

Q3 Natural Resource Market Commentary

Worries about a looming global recession and fears that global trade wars will continue to expand produced weakness in almost all commodity markets in Q3. "Risk-on" investments, which included most natural resources, were the poorest performers during the quarter, whereas "risk-off" investment strategies flourished. Demonstrating the extent of investors' fear and their desire to pile into "risk-off" assets, US Treasuries soared in price and yields plummeted. The 30-year US Treasury yield hit an all-time low of 1.97% in August. Also, the dollar amount of sovereign bonds sporting negative yields surged to $17 trillion, up from $10 trillion earlier this year. The US stock market actually rose slightly during the quarter—a little over 1%--but resource related equities were weak. For example, the S&P North American Natural Resource Sector Index (an index heavily weighted to the North American energy sector) fell 7.5%, and the S&P Global Natural Resource Index, which has a much heavier weighting in metals and agriculture, fell 6.7%. The only bright spots in global resource markets occurred in nickel and precious metal prices. Indonesia pushed forward its ban on nickel concentrate exports from 2022 to 2019 which caused nickel prices to surge 35% during the quarter. Nickel is a necessary metal in the production of lithium-ion batteries and Indonesia is trying to force nickel users, primarily China, to build a nickel smelting and processing industry within Indonesia. Precious metal prices were strong during the quarter. Weakening economic activity, combined with two interest rate cuts by the US Federal Reserve, with increasing talk of more interest rate cuts to come, put a firm bid under the precious metal complex.

But by far the most serious event to shake global resource markets in Q3 was the drone attack and partial destruction of the Khurais oil field and the Abquiq processing facilities in Saudi Arabia over the week of September 14. Approximately 5 mm b/d of production and processing capacity was knocked out. Although the news coming from Saudi Aramco indicated that a significant amount of this lost capacity has been brought back on line, our sources tell us that 2 to 3 mm b/d of processing capacity remains off line. Oil prices surged 15% on the Monday following the attack, but since then oil prices had given back all their gains. Even with the September price spike, oil prices for Q3 fell 7%. Oil-related equites were even weaker. E&P stocks, as measured by the XOP ETF, fell almost 18% and oil service stocks, as measured by the OIH ETF, fell over 20%. Since bottoming in Q1 of 2016, oil prices are now up over 120% off their lows. In one of the biggest divergences we have ever seen, oil stocks are now down 10% and oil service stocks are now down over 40% over the same period. As we have repeatedly pointed out, energy-related equities have never been priced cheaper relative to underlying value and we believe that huge profits will be made by investing in the energy stocks today. We know we sound like a broken record on the subject of oil-related investments, but our research continues to point us in a very bullish direction.

As we discussed in the at the beginning, the production slowdown experienced by the US oil shales in the last nine months is the inflection point we have long discussed. Our research tells us that the robust growth exhibited by the shale plays in the US will be near impossible to repeat as we progress into the coming decade. At the same time the shales are slowing, non-OPEC conventional oil production outside of the US has turned negative and our analysis tells us that large disappointments loom in this still critical and underappreciated sector of the oil market. Everyone thought that 2019 would see a year of strong non-OPEC growth outside of the US. For example, the International Energy Agency (IEA) originally estimated that non-OPEC/non-US supply would grow by 600,000 b/d. However, the IEA has severely revised downward these optimistic estimates to only 100,000 b/d and we believe these numbers will be revised negative before 2019 is over. For 2020 the IEA is again projecting strong non-OPEC production outside of the US—up 800,000 b/d. Again, we believe this number is far too optimistic. Please read the oil section of this letter in which we talk about the reasons why the IEA's 2019 projection of for non-OPEC ex the US was far too hopeful, and why their 2020 projection will be far too optimistic as well. Although it has received no attention, global inventories for the first six months of 2019 should have built by over 160 mm b/d according to IEA numbers; however, actual OECD inventory builds, according to the IEA have only built by 60 mm barrels. The 100-mm-barrel discrepancy between the IEA's projected builds versus actually builds represents "missing" barrels—barrels that are supposed to be in inventory according to the IEA figures, but aren't. The IEA has spent most of 2019 revising down its estimates for demand, but the slowdown is not manifesting itself in inventory behavior. For the first six months of 2019, the IEA has reduced its estimates of demand to only 500,000 b/d, but if we are right, and these 600,000 barrels per day (b/d) of "missing barrels" represent demand underestimation, then oil demand is far stronger than generally portrayed. For a further discussion of all the missing barrels please make sure to read the oil section of this letter.

Regarding the bombings in Saudi Aramco and the October 11, 2019 news that an Iranian oil tanker was struck by two missiles in the Red Sea: historically, from 1970 to 2010, most analysts believed some sort of risk premium should be incorporated into oil prices to reflect the inherent instability in the Middle East. The Iran-Iraq war lasted nine years and constantly threatened Gulf oil supply. The Iraq invasion of Kuwait, resulting in the partial destruction of Kuwait's oil fields, completely curtailed Kuwait's oil supply (3% of world supply) for almost six months which took years to recover. Because of Middle East instability, oil prices traded significantly above their theoretical prices, based upon global inventory levels during this period. However, over the last several years, as investor bearishness towards energy has surged and US shale oil production has soared, not only has the Middle East risk premium disappeared, but you can make the case that a "negative" risk premium has crept into the market. This "negative" risk premium refuses to dissipate even after 50% of Saudi Arabia's production was curtailed after the drone attack. Our models show that oil prices should be $10 higher, given today's global inventory levels. Back in 1980, we calculated that the five Gulf state producers (Saudi Arabia, Kuwait, Iraq, Iran, and the UAE) represented 30% of world pumping capability. Today, even after surging production from the US shales, these same Gulf state producers still represent 24% of the world pumping capability. To think that a sustained supply disruption from the Gulf States will not have a significant impact on global oil supply-demand balances goes to show how out-of-whack and bearish investor psychology has become.

The natural gas bear market continues to grind on. Prices continued to drift downward during the first half of the quarter, bottoming at $2.10 in early August—a new low for the year—and then rallying in September. Continued weakness in natural gas continues to revolve around a simple issue---surging supply. For the three-month period ending in July, the Energy Information Agency (EIA) reported that US dry gas supply surged over 9% from the same period a year ago. Continued production growth from the Marcellus shale in Pennsylvania and West Virginia, the Utica shale in Ohio, and continued surging growth of gas production from the Permian basin shales, primarily the Delaware side, were the biggest contributors to a huge gain in supply.

After peaking at almost $14 per thousand cubic feet back in the summer of 2008, natural gas prices have declined by almost 90% and are about to enter the eleventh year of their bear market. As most of you know, we love to get involved in long, drawn-out bear markets. The more bearish investors become, the more we like to roll up our sleeves and do the research to uncover important trends in supply and demand before they become recognized by the general investment public.

As the natural gas bear market dragged on and on, we have made repeated attempts to get bullish on North American natural gas prices. Each time, we quickly realized our mistake and retreated to the sidelines. Extremely strong demand was continually overwhelmed by surging supply. Today, fundamentals in North America natural gas markets look as bleak as they have ever been--the surge in gas supply seems endless. However, our research has picked out a potentially emerging data point that could have hugely bullish implications for North American natural gas markets. By far the biggest contributor to surging gas supply over the last 10 years has been the Marcellus shale. From almost zero production pre-2010, production of gas from the Marcellus shale in Pennsylvania and West Virginia has reached almost 23 bcf/day which today represents almost 25 % of total gas supply. Although investors often believe that production growth from such fields as the Marcellus is endless, this is not the case. Although they receive little attention today, the first two gas fields to be put into production, the Barnett and Fayetteville both rolled over and currently only produce half of their peak reached several years ago. In an interesting similarity, production from each field peaked once half of their ultimately recoverable reserves were depleted. In the case of the Marcellus, we do not have a good idea of what total recoverable gas reserves are, so trying to pick peak production in the field from both a standpoint of amount and time is extremely difficult to do. Over the years, we have made several attempts to estimate what the Marcellus's ultimate recoverable reserves might be, but we haven't been satisfied with our results. Using our self-teaching deep neural network, we have decided to try to again. Our initial findings are extremely important and produce a potentially bullish point. Given surging by-product gas production from the Permian, especially from the Delaware side, we are still neutral on the North American natural gas market. However, our neural network is telling us that we might be much closer to a peak in Marcellus (and Haynesville) gas production than we originally thought. If we are right, then the end stages of the great natural gas bear market might be playing out right in front of us.

Precious metals are one of the few sectors in the global resource markets to exhibit positive returns. Gold prices rose by over 7%, silver prices rose by almost 12%, and platinum and palladium prices rose by 6% and 9%, respectively. Gold- and silver- related equities were also strong. Gold stocks, as measured by the GDX ETF, and silver stocks, as measured by the SIL ETF, both rose by almost 5%. In last quarter's letter, we put forward our belief that the great bull market in precious metals has begun. The first leg of the gold bull market, which started back in 1999 and peaked out in 2012, was dominated by Asian buyers, both Chinese and Indian. We believe this leg of the gold bull market will be dominated by Western investors. As precious metal prices advance, we believe huge levels of speculation will emerge in various precious metal markets. We remain extremely bullish on gold and we continue to recommend investors carry full positions in both physical metals and precious metal-related equities. Rumors continue to circulate about an upcoming significant trade deal between the United States and China. If such a trade deal were to be agreed to, we believe we could see a significant short-term pullback in the gold price. If this happens, we would see the weakness as another great buying opportunity for precious metal investors.

Grain prices had a weak bias during Q3, as Trump continued to escalate his trade war rhetoric. During the quarter, corn and wheat prices both fell approximately 7% and soybeans actually eked out a small gain. Possibly signaling a desire to return to trade talks, the Chinese purchased 600,000 tonnes of soybeans in September, their largest purchase in over a year. Continuing a trend that started this spring, North American agricultural markets continue to be buffeted by extreme weather. This spring's record flooding in the Midwest, combined with an early onslaught of winter in the upper Midwest at the beginning of October, demonstrate how precarious global weather conditions have become over the last nine months. We have extensively discussed our belief that we are now entering a cooling period in global weather--a condition that will produce more unfavorable global growing conditions as we progress into the coming decade. Global temperatures have steadily risen over the last 70 years and consensus opinion believes this global warming will be massively disruptive to agriculture. We believe just the opposite. The warming trend experienced over the last 70 years has produced long stretches of incredibly good growing conditions for crops. For example, over the last 15 years, except for the North American drought year in 2012, most grain-growing basins have experienced an unprecedented stretch of excellent global conditions. Thus, global grain supplies have swelled even in the face of extremely strong global grain demand.

We believe we are entering into an extended period of global cooling, brought about by a long period of declining sunspot activity. (Please see our 1st quarter 2019 letter where we discuss at length this very controversial subject.) If we are correct, the world will experience an ever-increasing number of disruptive weather events that will negatively impact crops and their growing cycles. Although it's impossible to make a causal link, we are intrigued by the two very disruptive (and record-breaking) weather events that occurred this spring and in early October. In previous letters, we discussed how warmer weather had significantly boosted crop yields by extending the Northern Hemisphere's growing season: late spring and early fall frosts occurred with decreasing regularity. If we are right in our cooling trend thesis, we should see more disruptive weather events occur, especially during both spring and fall periods. The record-breaking rains experienced this spring and the near record-breaking blizzard of October 10th —a coincidence? We don't know, but we will continue to monitor global weather conditions closely.

We believe the weather disruptions experienced in 2019 have a high probability of being repeated in some form as we progress into the 2020 planting season. We believe we have entered into the first stages of a huge global agricultural boom and we recommend significant exposure to agriculture-related investments.

Uranium markets were quiet again in Q3. Spot prices increased by $1 over the last three months while contract prices were flat. Uranium-related equities fared worse with the majors down 9% on average during the quarter. In our last letter, we explained how the pending Section 232 ruling had resulted in fuel buyers waiting on the sidelines before renegotiating their expiring long-term contracts. As a reminder, the proposed ruling would have mandated a quota for domestic uranium far in excess of current US production. The administration struck down this proposal in July, but uranium buyers have been slow to reenter the market. We expect this will change in Q4 and could result in a uranium rally similar to what occurred in 2018.

While the market was largely quiet during the quarter, there were several bullish developments that went largely unreported. First, Kazatomprom extended their production cuts until at least 2021. Second, we believe Cameco is about to enter the spot market in a dramatic way during Q4 and this could have a material impact on price. Ever since Cameco curtailed production last year from their world-class McArthur River mine, they have stated their mine production would not be enough to meet their commitments. As a result, they would meet their obligations through a combination of purchased material and sales from their inventory. We estimate that Cameco's inventory has already declined from 20 mm pounds as recently as June 30, 2018 to 12 mm pounds today and so more and more material will need to come from the spot market to meet commitments going forward. While uranium bears believe there is an abundance of excess material around the world, something very strange happened when Cameco tendered for spot pounds earlier this year. Instead of being inundated with many offers, Cameco was only able to secure a small fraction of the material it tendered for. Nor did price seem to be the issue. Instead, the sellers all were willing to offer material for delivery many months away. This suggests that easily mobilized uranium inventories are much lower around the world than widely believed. Furthermore, the long lead time suggested the material would be sourced from small mining operations that would use the tender as a backstop to increase or restart production. We expect to see prices respond strongly over the next few months as several of these fundamental trends begin to be better appreciated by the market.

Except for a surge in nickel prices (up 34% during the quarter), most base metal markets were weak. For example, both zinc and aluminum prices fell 4.5% and copper prices fell 5%. Copper remains by far our favorite base metal. After a strong 2018, both copper and the related stocks have been lackluster performers so far in 2019. While investors remain concerned about Trump-related trade wars, they risk missing several critical bullish developments now showing up in the data. In September, the World Bureau of Metals Statistics (WBMS) made several revisions to an historical dataset that dramatically tightens copper's supply and demand balances. Demand was revised higher in both South Korea and Russia by 100,000 tonnes in a market that has grown on average 500,000 tonnes per year over the past several years. More dramatically still, mine supply was revised lower by an incredible 500,000 tonnes in 2018 due to revisions in Zambia, Kazakhstan, and Indonesia. Looking forward, we predict disappointments in mine output will continue. Several major projects suffered delays or postponements including Rosemont in Arizona and most notably Oyu Tolgoi in Mongolia. Oyu Tolgoi, one of the most anticipated new mining projects in the world, announced major geotechnical problems in the development of its underground block cave operation. While it remains to be seen what ultimate impact this will have on the project, it has certainly resulted in a multi-year delay. Complicating matters further, political turmoil in Chile has resulted in widespread labor disputes there that will impact production. We believe the net result is a copper market that has already slipped into deficit and will continue. We are maintaining our copper investments, confident it has one of the best supply and demand outlooks of any commodity.

Oil: A Market Divorced from Reality

In the thirty years we have been investing in global natural resource markets, we cannot remember seeing greater value than we do today in the global oil markets. With both crude and oil-related securities, the price action appears to have completely divorced itself from underlying fundamentals.

By any measure, oil and oil-related securities are radically undervalued. Over the last 120 years, we estimate it took 17 barrels of oil on average to buy one unit of the S&P 500. Today it requires over 53 barrels. The only time it has taken more was during the parabolic dotcom blow off–incidentally an excellent time to become an oil investor. At the same time, energy-related equities now make up a mere 4% of the S&P 500 by weight. Not only does this represent the lowest level in at least 20 years (when our records begin), 75% below the peak levels reached in 2008 at which point energy stocks made up 16% of the S&P 500.

In particular, the bear market in oil exploration and production companies has created value that can hardly be believed. We analyzed the universe of all US-listed E&P companies with market capitalizations over $100 mm and proved reserves that are at least 50% oil. We then compared the current stock price to the net-debt adjusted SEC PV-10 measure from their 2018 10Ks. As you may recall, a company's PV-10 measures the discounted cash flow of all proved reserves at the prevailing oil and gas prices. Under normal market conditions, E&P stocks trade at a premium to their SEC PV-10, reflecting the expected value of any future reserves not yet "booked" in the reserve statement. However, due to the overwhelming bearishness among energy investors, the average company now trades at a 12% discount to its net-debt adjusted SEC PV-10 per share value. While we have seen individual companies trade at a discount, we cannot recall a time when the industry average was less than its SEC PV-10 value. We should point out that the price used in most companies' SEC PV-10 analysis for 2018 was $55 per barrel, not materially higher than today's price.

We also computed the discounted value of the companies' proved developed producing reserves (PDPs). This represents the most conservative possible measure of value: a company's discounted cash flow from currently producing wells only. As you might imagine, it is very unusual for an E&P company to trade at a discount to this most conservative measure. Today, we estimate that twelve of the twenty-nine companies in the universe are trading at a discount to their PV-10 value using only their PDP reserves. Furthermore, the average premium to PDP PV-10 value across the entire industry is now only 7%. Once again, we have never seen anything remotely like this before. Investors often act irrationally at the bottom of long, drawn-out bear markets and we believe that is what we are witnessing today.

While the market can famously stay irrational longer than most investors can stay solvent, what we are experiencing today is truly extreme. An entire industry is nearly priced as though it will simply run off its existing assets. How can this be? We believe there are simply no buyers left. In past cycles, as energy prices fell and E&P stocks sold off, two groups of investors would begin to accumulate positions: natural resource specialists and value investors. Our analysis tells us that natural resource funds continue to suffer material redemptions as investors look to reallocate capital away from the industry. We estimate that nearly 25% of the industry's assets under management are flowing out through redemptions each year and this figure shows no sign of abating. As a result, resource fund managers are constantly forced to sell positions to meet redemptions, instead of stepping in to take advantage of the deep value. Value managers are also suffering net redemptions. After a difficult ten-year period, growth continues to outperform value and investors continue to chase the momentum of the former by selling the latter. In past cycles, value investors could be counted on to buy during extreme bear markets. but today they are either on the sidelines or liquidating positions to meet redemptions as well. In fact, active managers in general are seeing capital being allocated away into passively managed index funds. As we mentioned earlier, energy now makes up its lowest ever weighting in all the major indices. Therefore, as capital gets redirected from actively managed funds towards passive index funds, energy shares end up being liquidated.

There are no natural buyers for natural resource stocks in general and energy stocks in particular. This has allowed the sell-off to be more severe than past cycles and resulted in unprecedented value for those able to invest in this most contrarian space.

Often at the bottom of intense, grinding bear markets or the top of bull markets, investors will create a narrative to help explain the extreme price action. The prevailing consensus view is that oil market fundamentals are bad today and getting worse. Most analysts believe the market is currently in surplus and that this surplus will accelerate as weak demand is met by ever-growing shale production. At the same time, the EV threat looms and is expected to leave oil worthless within several years. This outlook appears to be corroborated by the sell-off in E&P stocks, reinforcing the negative feedback loop.

Unfortunately, the story investors have created to help explain today's energy bear market is fundamentally incorrect. While it may be counter-intuitive, the oil market is in deficit today and has been for nearly three years. After peaking at nearly 450 mm bbl above average, OECD inventories have repaired themselves by 75%. In the US (by far the largest source of OECD inventories), core inventories drew relative during the first nine months of 2019 by 40 mm bbl during a period that normally sees them build by 1.4 mm bbl. This implies the market was undersupplied by 150,000 b/d. While the data for the OECD as a whole came in slightly weaker, it still suggested a balanced market for the first nine months of the year based upon preliminary data. We should point out that the IEA has been revising its most recent inventory data and so we will have to wait to see if the most recent data ends up being revised down from here. Both WTI and Brent markets remain firmly "backwardized," confirming the market is indeed tight.

Investors remain very concerned about the impact of slowing economic growth on global oil demand. While Q2 did show some softening, there have been several very bullish developments that most investors seem to ignore. For example, analysts focused all of their attention on the IEA's recent downward revision of 2020 global demand projections by 100,000 b/d over the course of the last three months. However, at the same time the IEA quietly revised historical demand higher by 190,000 b/d in 2017 and 110,000 b/d in 2018–a fact that few people wrote about. Notably, Q4 of 2018 was revised higher by a very large 300,000 b/d.

Our models tell us that more revisions are forthcoming. As always, our analysis revolves around the "missing" barrels. For example, the IEA still claims after its latest set of historical revisions that global demand for all of 2018 equaled 99.3 mm b/d while total supply equaled 100.3 mm b/d. This suggests that inventories should have grown by 1 mm b/d or 365 mm b for the full year. Instead, the IEA reports that inventories were unchanged for the year. We refer to the "missing" barrels as oil that was produced but neither consumed nor put in storage. We have long argued that "missing barrels" are a clear indicator that the IEA will revise higher its demand figures and once again that has been correct. The IEA has a long history of demand underestimation. In 8 of the last 9 years, they have been forced to revise global demand higher by 1.1 m b/d on average (a number that is creeping higher). Despite this chronic underestimation and the continued presence of "missing barrels," investors continue to ignore the warning signs of stronger than expected demand. For example, all of the headlines we've read focused on the small downward revisions to future demand projections (by an agency that systematically underestimates demand) while none have focused on the larger positive revision to actual historical data. If we are right and the majority of the "missing" barrels are eventually included in global demand, then 2018 demand likely averaged 100.4 m b/d or an incredible 2.2 m b/d higher than 2017. That is the largest annual growth in eight years.

In our introduction, we discussed how US shale growth has rapidly slowed. As a result, total US crude production (both shale and conventional) was flat from January 1 to June 30. Compare that to nearly 700,000 b/d of growth for the first half of last year. Even adding in natural gas liquids, total US liquids production only grew by 300,000 b/d for the first six months of the year compared with 1 mm b/d for the first half of last year. Given that US oil rig counts have now fallen by 15% and that drilling productivity seems to have stagnated, we expect these trends will only get worse from here. Investors have become far too complacent about global oil supply. For example, the IEA still expects US liquids production to grow by a very robust 1.6 mm b/d year-on-year in 2019. For this to occur, US liquids production would have to surge by 1.0 m b/d between June 30 and December 31, completely bucking the trend of the first half. Given the falling rig count this simply is not feasible. Furthermore, the IEA expects this growth to continue into 2020. Their latest report projects the US will grow production by another 1.3 m b/d which implies growth of 1 m b/d from January 1 to December 31–again, something we think is not possible without a material increase in drilling.

Adding to the supply issue, conventional non-OPEC production outside of the US continues to disappoint. We first addressed this issue in our 3Q2016 letter and have revisited it several times since then as we believe it remains the most ignored driver of global oil balances going forward. Last year marked the worst year ever for conventional oil discoveries and caps nearly two decades of lackluster results. We estimate that conventional non-OPEC production has exceeded discoveries by a staggering 170 bn bbl over the past six years. Conventional non-OPEC reserves are being hollowed out and we have long made the case that you are actually starting to see this in the production numbers. When the IEA first released estimates for 2019 last summer, it expected total non-OPEC supply outside of the US and Russia (we are excluding Russia because their production is actively being curtailed today) would grow by 350,000 b/d including biofuels and refinery processing gains. We have long argued this would be impossible based upon the dearth of new projects coming online. In their latest report, the IEA has now revised this growth down to zero. Even including OPEC NGLs (not part of the OPEC quotas), non-OPEC supply outside the US and Russia is only expected to grow by 100,000 b/d in 2019. However, our models tell us more revisions are needed. For example, while the IEA revised down their growth assumptions for Norway and Brazil for the first half of 2019, they actually increased their estimates for the second half and for 2020. The IEA now expects 2020 non-OPEC growth outside of the US and Russia to reach a robust 1 m b/d including OPEC NGLs. Once again, these figures are far too high and will need to be revised down.

Analysts point to new production from the Brazilian Lula and Búzios pre-salt fields (expected to reach 400,000 b/d) and the Johan Sverdrup project in Norway (expected to reach 440,000 b/d) when justifying 2020's expected growth. While these projects are indeed large, our models tell us they simply will not be enough to reach the IEA's overly optimistic growth assumptions. While this may sound outlandish, consider that every year major projects contribute to new non-OPEC production and every year this is offset by a certain amount of base decline. We model all major non-OPEC projects and can compare the gross additions expected in 2020 with those of the past years. Focusing on non-OPEC conventional production outside the US and Russia, we estimate that new projects have added 1.2 m b/d of new production each year between 2012 and 2018. In 2019 we estimate this figure accelerated to 1.5 m b/d of production. At the same time, we estimate that production from this group has not grown since 2012 suggesting that base declines have been roughly 1.2-1.4 m b/d. Our same models suggest that even with the new projects in Brazil and Norway, total major projects will only add at most 1.7 m b/d of production next year. Given 1.5 m b/d of new production from major projects in 2019 has so far led to no net growth, it seems unlikely that 1.7 m b/d of production from new projects will result in 1 m b/d of new net growth in 2020. Instead, we think that the IEA will be forced to revise down its projections materially, much the same as it did in 2018 and 2019.

As a result of stronger than expected demand, slowing shale growth, and modest non-OPEC growth outside the US, we expect global oil markets will remain in deficit as we move through the remainder of 2019 and into 2020. For the second half of 2019, the IEA estimates global demand will average 101.3 m b/d while total non-OPEC supply will average 65.4 m b/d. Assuming OPEC NGLs average 5.5 m b/d that leaves the call on OPEC at 30.4 mm b/d while production in Q3 averaged 29.4 m b/d. These balances imply a market in deficit by 1 m b/d as we progress through the rest of the year.

Turning to 2020, the IEA expects global demand to average 101.5 m b/d, but we believe this figure will need to be revised higher. The "missing" barrels averaged 450,000 b/d during the first half of 2019, and we expect demand will ultimately need to be revised higher by a comparable amount for both 2019 and 2020. If our models are right (and they have been so far to date) then demand could reach 102 m b/d in 2020. Non-OPEC supply is expected to grow by a very strong 2.2 m b/d next year, but as we have discussed we believe this is not possible. The IEA still expects the US can grow by 1.3 m b/d next year, but we think this figure is overstated by at least 300,000 b/d under the most lenient assumptions. Non-OPEC production outside the US (including OPEC NGLs) is expected to grow by 1 m b/d but as we discussed earlier this seems unlikely. Instead, we think this group will be lucky to see growth of 400,000 b/d. As a result, we expect non-OPEC production outside the US to average 53.6 m b/d in 2020. These balances would leave the call on OPEC at 30.3 m b/d – or nearly 1 m b/d more than OPEC's recent levels.

Global oil markets remain tight despite investor concerns regarding global growth, shale production, and the EV. At the same time, we think it will become more challenging to find high-quality E&P investment opportunities with ample remaining drilling inventory. This is where we continue to focus all of our attention as we move forward. We are now turning our neural network to individual companies to better analyze their asset bases and the results thus far have been very interesting. In our next letter, we will write extensively about our results and hopefully put to bed the notion that all shale companies are chronic value destroyers.

Natural Gas: A Potential Turning Point in a Decade's Long Bear Market?

The shale gas revolution began in earnest in 2005. Even though the shales were being aggressively developed, shale gas production in 2010 still represented only 20% of US supply. Of the 21 trillion cubic feet (tcf) of dry gas produced in 2010 (or 58 billion cubic feet per day [bcf/d]), 80% was still produced from conventional reserves. Shale gas production in 2010 remained concentrated in two basins: 40% of total shale production came from the Barnett; 30% came from Haynesville.

Today, US dry gas production has surged to over 90 bcf/d and the contributions from shales and conventional sources have flipped. The shales now represent almost 80% of total US dry gas production (70 bcf /day) while conventional gas production represents just a little over 20%. The contributions from various basins have also shifted significantly over the last nine years. The Barnett and Haynesville have gone from representing 65% of US natural shale gas production in 2010 to only 12% today. The largest source of gas supply growth by far over the last nine years has come from the Marcellus shale. Today the Marcellus produces 22.5 bcf/d, representing almost 25% of total US dry gas supply, making it the largest basin in the country by a wide margin. You cannot overstate the importance of the Marcellus to the US gas market.

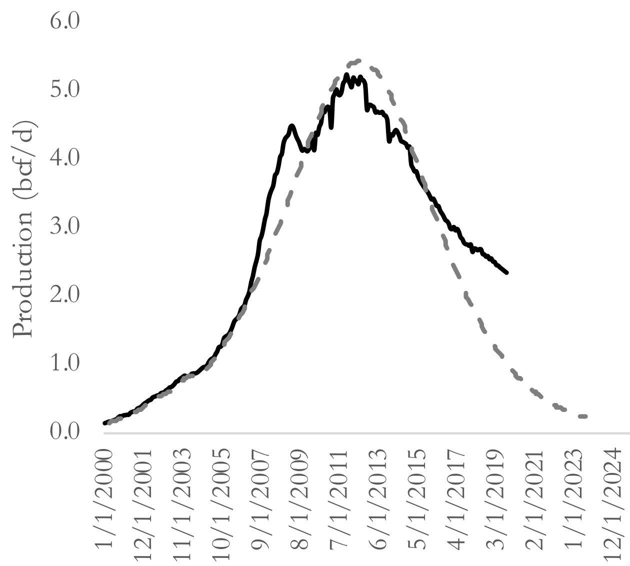
As we mentioned in the Q 3 Natural Resource Market commentary of this letter, we have spent much time over the last five years trying to better understand when the grinding North American natural gas bear market might end. We are seeing an extremely interesting data point emerge in the Marcellus shale (as well as the Hayneville, the second largest gas field in the US) that could provide an answer. While we do not believe the natural gas bear market is gas is yet over, this potentially bullish trend must be closely monitored. These trends may provide investors the signal that the great gas bear market is now entering its final innings.

Back in November 2016, I was the luncheon speaker at the Doyle Trading Consultants' annual fall conference. Although the event was a coal conference, I spoke on the future of North American natural gas and whether there was any hope that the bear market, then in its ninth year, might be drawing to a close. Absent a short-term weather-related spike, we offered little evidence that the bear market was nearing an end. We explained how supply growth would continue to exceed demand growth even given the coming build-out of US LNG export facilities.

However, we did mention at the very end of our presentation that any bullish long-term thesis would need to revolve around one issue that few investors were discussing. A shale field (whether it be gas or oil) has many of the same characteristics as a conventional field. In conventional oil and gas fields, production typically peaks and then declines once half of the recoverable reserves have been produced. This principle was first put forward by the famous and controversial geologist King Hubbert in the 1940s. Although petroleum geologists and engineers debate the underlying drivers, the empirical evidence is hard to refute, and the principal is largely accepted as fact today. For those trying to pick the end of the natural gas bear market, one had to determine when the Marcellus gas field would peak and then decline.

The difficulty in applying Hubbert's theories revolves around estimating a field's total recoverable reserves. The relentless advancement of technology has pushed recovery factors constantly higher across almost all oil and gas fields. This in turn has led to rising recoverable reserve estimates. In our previous letters, we used Hubbert's theories to make several predictions, some of which have been right and some of which have been wrong. For example, we correctly estimated when the giant Saudi Ghawar field would roll over. However, we were too early in claiming that the Bakken and Eagle Ford had peaked. Our Q3 2016 letter, discusses Hubbert and his theories, including all the drawbacks and limitations.

Hubbert's theories are controversial, but natural gas production from two of the three oldest gas shales, the Barnett and the Fayetteville, has long since rolled-over, and the production profiles from both fields are now tracing out near-perfect "Hubbert Curves."



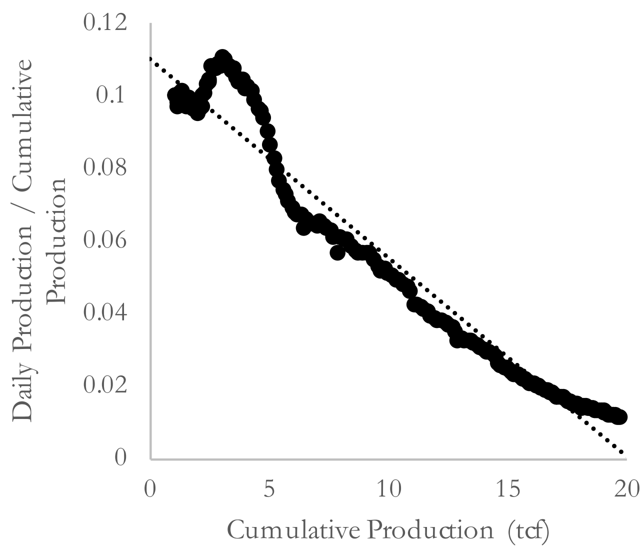
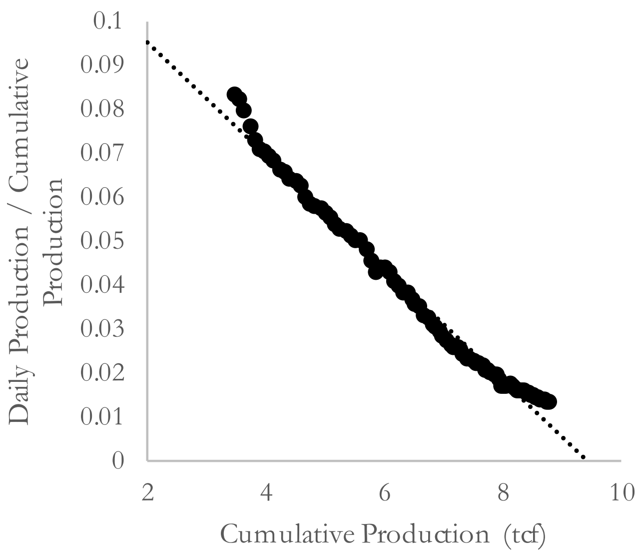


Exhibit 2: Barnett Production Profile & Hubbert Linearization
Source: EIA, G&B Models.



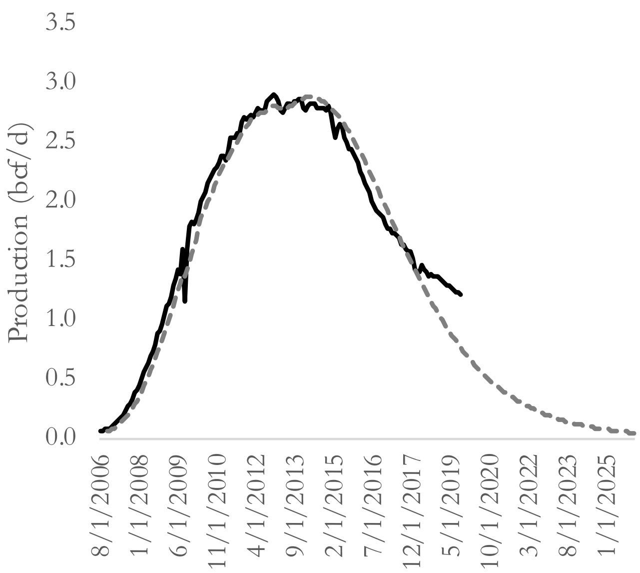


Exhibit 3: Fayetteville Production Profile & Hubber Linearization
Source: EIA, G&B Models.

The third field, the Haynesville, highlights one of the major problems with Hubbert's theories. The Haynesville first produced significant quantities of gas in 2009. By 2012, production had surged to over 7 bcf /day and represented 10% of total US supply. Production peaked unexpectedly and by early 2016 had fallen by half as the economic parts of the field were drilled up. Many natural gas investors (including ourselves), thought the Haynesville would continue to decline. However, by 2016 Haynesville operators had significantly increased both the lateral lengths and proppant loadings of their wells with tremendous positive results. By 2017 production once again started to strongly grow. Today, production has reached new highs at nearly 9 bcf/d. The productivity improvements associated with longer laterals, larger proppant loadings, and more frac stages significantly increased the ultimate recovery of the field.

With the Marcellus, if we can predict when gas production from the field peaks, it could be extremely important data in determining when the gas bear market might end. However, our previous attempts to estimate total recoverable gas from Marcellus have proved frustrating. But now we can ask our newly designed neural network to make that estimate and be more confident about when the Marcellus's production will peak.

We have become more motivated to undertake this project after meeting with multiple Marcellus operators. We always ask managements how much Tier 1 drilling acreage remains in their inventory. In the past, Marcellus operators would respond that they had decades and decades of Tier 1 acreage left to drill. However, the responses from these same companies' have recently become more somber with some operators even suggesting their Tier 1 drilling inventories might be less than 10 years.

Before we discuss the Marcellus, let's step back and analyze the production history of both the Barnett and Fayetteville fields -- the first two gas shales to be developed. Both fields have peaked, and production has clearly rolled over. As you can see from the two charts below, both the Barnett and the Fayetteville have traced out near-perfect "Hubbert Curves." The "Hubbert Linearization" suggests the Fayetteville will ultimately recover 9 tcf while the Barnett will recover 20 tcf. We compared the Hubbert Linearization with the recoverable reserve estimation made by our neural network, and the results were remarkable. Our neural network identified 17,000 possible Barnett wells of which 15,000 have been drilled and completed. Total expected reserves from these 17,000 wells is expected to total 23 tcf of natural gas of which 20 tcf (or 85%) have already been produced. Unlike the Hubbert Linearization, our neural network identifies each individual well location making it very much a direct or "bottoms up" estimate. Remarkably, the neural network predicted that total recoverable reserves would be within 15% of the Hubbert Linearization. Moreover, according to the neural network, production from the Barnett peaked and rolled over within a few months of when half the recoverable reserves were produced.

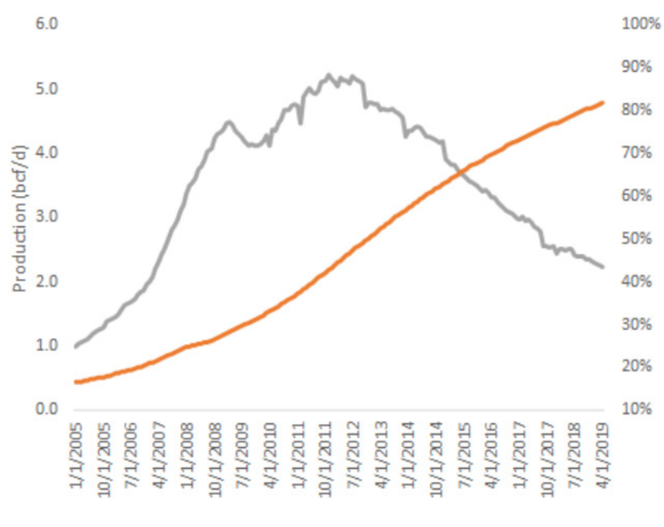


Exhibit 4: Barnett Production & Field Recovery Neural Network
Source: ShaleProfile, G&R Neural Network

Turning to the Fayetteville, our neural network identified just over 6,000 drilling locations of which 5,600 have been drilled to date. In total, our neural network estimated total recoverable reserves at 10 tcf of which 8.9 tcf have already been produced. Once again, our neural network (based on projections of individual wells) comes very close to the Hubbert Linearization, which projected 9 bcfof recoverable gas. Just like the Barnett, production from the Fayetteville seems to have peaked and rolled over within a few months of reaching the "half-way" point in terms of recoverable reserves. Our neural network tells us that 85% of the Fayetteville's reserves have now been produced and that production has little to no chance of ever recovering.

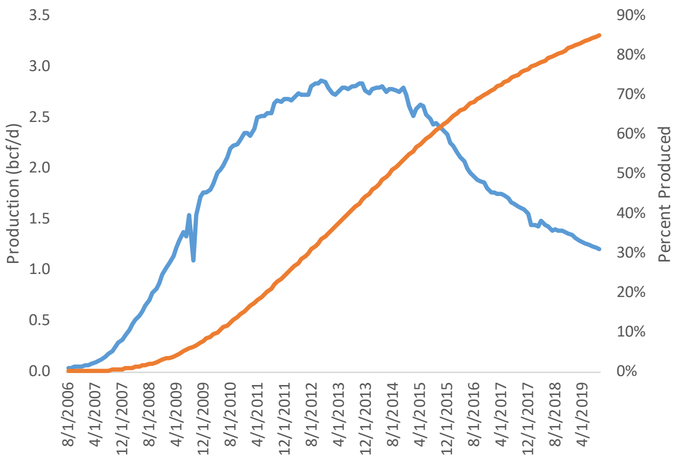


Exhibit 5: Fayetteville Production & Field Recovery Neural Network

Source: ShaleProfile, G&R Neural Network

The neural network is equally as insightful when considering the Haynesville. Our models identified 10,000 possible drilling locations that will recover 50 tcf of natural gas in aggregate. As we discussed, production from the Haynesville first peaked at 8 bcf/d in 2011 before declining by nearly half. The field had only produced 4.5 tcf of gas by 2011 and in retrospect, given we expect the total recoverable reserves are 50 tcf, it is no surprise that production picked back up. Indeed, today production is nearing 10 bcf/d – nearly 20% higher than the last peak. We estimate the Haynesville's cumulative production to date is approximately 20 tcf or 40% of projected total. As such, we believe the Haynesville will continue to grow somewhat from here.

What predictions can we make about the Marcellus? A Hubbert Linearization of the Marcellus is somewhat problematic because the field has been pipeline constrained for much of its development (Hubbert's theories apply to unconstrained development). Looking at the plot, Marcellus production appears to still be in its early "noisy" stage of growth before the linearization settles into a straight line from which recoverable reserves can be estimated. This is precisely why we have avoided making a prediction about the Marcellus in our past letters.

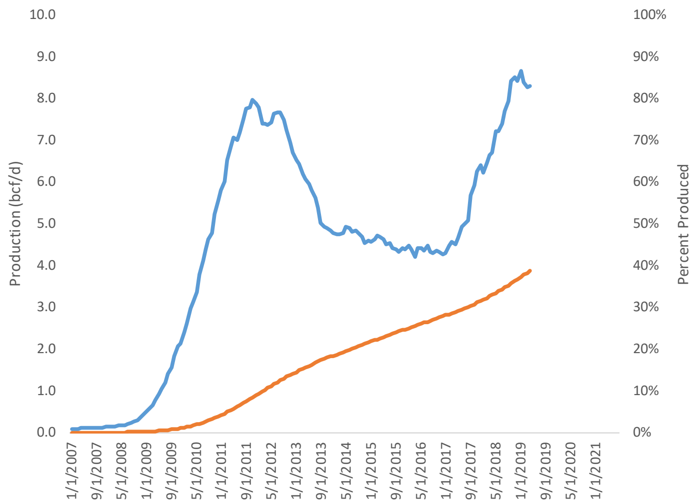


Exhibit 6: Haynesville Production & Field Recovery Neural Network

Source: ShaleProfile, G&R Neural Network

Our model identified 20,000 drilling locations in the Marcellus of which 14,000 have been drilled to date. In total, we expect these wells will recover 92 tcf of natural gas making the Marcellus nearly twice as large as the second largest shale gas field, the Haynesville. We estimate the Marcellus has produced 37 tcf of gas to date, or 40% of the total recoverable reserves. This implies that the Marcellus can continue to grow until another 8 tcf of gas has been produced. At today's production levels this amounts to only another 12 months before the Marcellus has produced half of its ultimate recoverable reserves. While this claim may sound shocking, if we extrapolate the Hubbert Linearization form the last 30 months of data, it implies total recoverable reserves of 90 tcf of gas, very close and consistent with the recoverable reserve estimate made by our neural network.

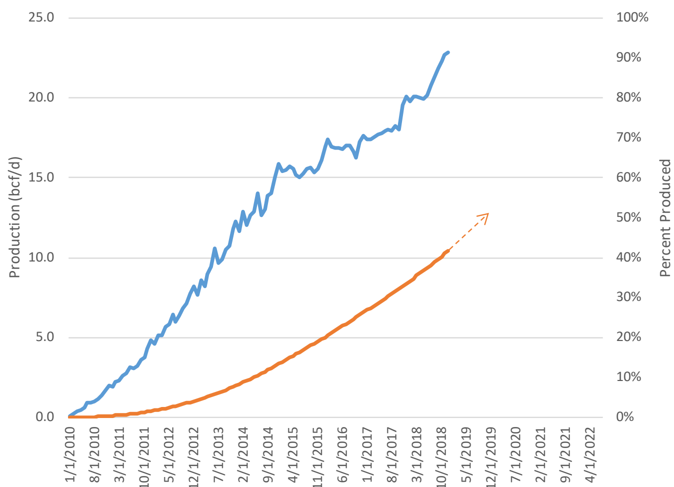


Exhibit 7: Marcellus Production & Field Recovery Neural Network

Source: ShaleProfile, G&R Neural Network

If this analysis is correct, then the largest bearish factor in today's natural gas market (i.e. Marcellus production) may be nearing an end.

In carrying out our analysis, we came across another very interesting observation that lends credence to our claims. Production in both the Barnett and the Fayetteville peaked once half of their reserves were produced. However, another commonality to both fields is that production peaked once 60-65% of their Tier 1 wells had been drilled and completed. Today, we estimate that both the Marcellus and the Haynesville have produced 40% of their recoverable reserves. We also estimate that the 60% of the Marcellus's Tier 1 well have been drilled and that 55% of the Haynesville's Tier 1 inventory has been drilled as well. If both of these fields follow a Hubbert Linearization and peak within the next 12-18 months having produced half of their reserves, they will also do so having drilled 60-65% of their best wells---just like the Barnett and Fayetteville. It's another data point confirming that both fields are very close to peaking.

Again, we do not think the bear market in US natural gas is over, but we now believe the end is quickly approaching. The fact that both the Marcellus and Haynesville—25% and 10% respectively of US production--are very close to peaking means that future growth in US gas supply will slow dramatically in the next five years. Most of the future growth in US production will have to come from the Permian. In our next letter, we will discuss the implications of slowing US shale production, as well as the global demand trends now firmly in place. We will also use our neural network to refine projections of future natural gas production from all the gas fields, including the Marcellus and the Haynesville.

We have been bearish on gas for a very long time, but we want our readers and investors to know that evidence is gathering that the grinding bear market in natural gas, now in its 12 year, is now drawing to close.

The Western Investor Reenters the Gold Market

We believe that the upcoming next leg of gold's bull market will be driven by western buyers, a subject we discussed in our last letter. Last decade's gold bull market, which lasted 10 years and saw the price of gold rise almost seven-fold, was dominated by buyers from the East—primarily from China and India. In the first leg of last decade's bull market, which ended in 2008 when gold hit $1,000 per ounce, western gold market participants spent most of their time not buying but selling gold. For example, western central banks only stopped selling their gold in 2008 and hedge funds and other western speculators were significantly short throughout much of the advance. Also, a large number of western gold producers were still forward-selling their gold production as the first leg of the gold bull market unfolded. It took all the way until 2009 for the biggest proponent of gold forward-selling—Barrick Corp—to admit that it could no longer stand the financial pain of maintaining a massive short position. In September 2009, they announced they were closing out their forward sale program and would take a $5.6 billion loss. Also, it was only after the 2008 financial crisis that we began to see any interest in gold from western investors. Several high-profile hedge funds made pronouncements that they had accumulated gold positions, but the hedge funds were late to the game. By 2009, the first leg of the gold bull market only had three years left before it peaked out and, once the gold price began its pullback at the end of 2011, western investors spent the next four years liquidating all the gold they had accumulated since 2008—almost 1,500 tonnes.

The complete absence of western buying, combined with the measured buying by both the Chinese and Indians, who thought gold was a cheap asset class that deserved long-term accumulation, produced a long bull market characterized by low volatility and little speculative activity. As opposed to the gold bull market of the 1970s, the gold bull market of the 2000s was extremely measured and orderly and the advance from $250 to $1,900 per ounce received little comment from the financial press.

For those with long memories, remember how different the 1970s gold bull market was from the one experienced last decade. The final leg of the 1970s bull market in gold was driven by western investors and both gold and silver exhibited high levels of speculative activity which included the attempted corner of the silver market by the Hunt Brothers. In 1979 alone, the gold price advanced by over 150% and silver exploded by over 230% in price.

Are we beginning to see the return of the western interest in the gold markets? We believe that we are. Tracking the accumulation of gold and silver through their respective physical ETFs is a good way to gauge the movement. The 17 physical gold ETFs we follow have shown consistent accumulations throughout 2019. By our calculation, they have accumulated 40 tonnes of metal in Q1, 59 tonnes in Q2, and 214 tonnes in Q3. The accumulations continue into Q4. In the first three weeks of October, another 35 tonnes was accumulated. For all of 2019, physical gold ETFs have accumulated 350 tonnes of metal and total holdings now stands at 2,560 tonnes— almost equal to their 2012 peak. Accumulations also continue in the physical silver ETFs we track. In Q1, the nine we track shed 166 tonnes of metal. However, starting in Q2, they began an aggressive period of accumulations. In Q2, silver ETFs accumulated 470 tonnes, in Q3, they accumulated 2,900 tonnes, and the accumulation continued into Q4. For the first three weeks of October, silver ETFs accumulated an additional 59 tonnes. Over the last eight years, the total silver held by ETFs traded in a range between 15,000 and 16,000 tonnes, but as you can see from the chart below, total accumulations, now standing at 19,500 tonnes, have definitely broken out to the upside after being range-bound for 10 years.

In our last letter, we reiterated our gold price target of $12,000 per ounce—a price target that will potentially be reached in a period of huge speculation not unlike one we saw 40 years ago. The huge amount of money created by central banks has combined with the massive increase in total indebtedness over the last nine years have led to major distortions including the emergence of widespread speculation in the global bond markets. This distortion in particular is apparent when considering the recent sale of 30-year German debt with negative yields. All of these distortions have created the perfect backdrop for the upcoming bull market in precious metals.

Western investors have begun to recognize this and have started placing their bets. The gold bull market has now begun.

Will US Crop Conditions Disappoint?

Crop conditions in North America continue to be strained because of the record- breaking spring rains and resulting flooding in the upper Midwest that caused the 2019 crop to be planted later than ever.

The extremely late planting of crops has resulted in both corn and soybean crops of relatively poor condition. For example, according the United States Department of Agriculture (USDA), the corn crop is only 58% mature, the slowest maturity on record for the beginning of October. Normal corn maturity at this point should be 85-90%. Only 72% of the US soybean crop has dropped its leaves versus 90% last year.

The condition of both crops is below last year's levels and the five-year averages. Only 56% of this year's corn crop is rated "good to excellent" versus last year when 69% met that rating. On a five-year basis, 60% of the corn crop usually meets that rating by this point. Only 53% of this year's soybeans are rated "good to excellent" which unfavorably compares with last year's 68% which is also the five- year average.

Both corn and soybean harvests are far later than average because of their late maturities. As of the first week of October, only 15% of corn has been harvested versus a five-year average of 25%. In soybeans, only 14% of the crop has been harvested versus a five-year average of 20%.

The late maturity of both crops combined with their poorer-than-average conditions make them vulnerable to any adverse fall weather conditions. The huge near record-breaking blizzard and resulting freeze in October which extended from southern Colorado through western Nebraska, from the Dakotas up into Canada, can only produce further harvesting problems. Although most grain analysts have shrugged of the effect of the early blizzard, we believe we could see further reductions in yields of both crops. An October 14 Bloomberg News story reported that "Roger Rix, who farms near Grotton, SD, was hustling with his sons last Wednesday to harvest soybeans before the storm hit. He suspected two thirds of their soybean acreage would still be in the field when the storm was forecast to arrive this week. 'We know it's going to be a disaster,' said Mr. Rix."

The article went on. "Farmers in the Dakotas say the snow could delay their harvest by as much as three weeks. That will leave them scrambling to harvest as colder weather advances. Some crops could go unharvested until next spring."

Even absent the recent blizzard, we believe we will see further downward revision to both corn and soybean harvests. The USDA has historically overestimated both corn and soybean yields in years when there is a late start to the planting season and crops fall well behind in their maturation cycles. For example, in three years that had late planting and maturation cycles—1983, 1993, and 1995—the USDA overestimated their midsummer yield estimates of corn by, on average, 10 bushels per acre and soybean's yield by 2.5 bushels per acre. Back in August, the USDA estimated US corn yields to be 169.5 bushels per acre. In their most recent October Crop Production report, they only reduced their yield estimate slightly to 168.4 bushels per acre. Given that 2019 has been the worst in history regarding lateness, we believe there is a high probability that corn yields will be reduced significantly in upcoming USDA Crop Production reports. Regarding soybeans, it looks like the downward revisions in their yields has begun. In its most recent report, the USDA reduced soybean yields to 46.9 bushels per acre—a drop of 1.6 bushels per acre from its August estimate. If history is any guide, we should expect another 1 bushel drop in soybean yields in the upcoming USDA reports.

Further reduction in yield assumption will have a big impact on both crops. The 1.6 bushel per acre drop in soybean yields has already put huge downward pressure on the 2019-2020 soybean carryout estimates. Soybean carryout estimates, originally projected to be as large as 750mm bushels, have been reduced to only 460 mm bushels in the latest USDA reports. Because of the reported USDA resiliency in corn yields, 2019-2020 corn carryout still stands at almost two billion bushels of corn. However, just to show you how sensitive this carryout figure is to yield assumptions, if corn yields fell by 10 bushels per acre, the 2019-2020 corn carryout would collapse to only a billion bushels.

The historical relationship between late planting seasons and downward revisions of crop yields in North America, combined with the near record blizzard conditions in the upper Midwest which has significantly delayed the 2019 harvest in those areas, leads us to believe there will be significant tightness in global grain markets. The USDA has already reduced its 2019-2020 soybean carryout by almost 40% because of yield estimate reductions. At 460 mm bushel carryout, the stocks-to-usage ratios in soybeans is nearing 10%--a point where we usually begin to see significant upward price pressure. Although the downward pressure on corn yields has only started, we believe that we will see further downward revisions, which will produce significant market tightening.

Corn, soybeans, and wheat have all rallied between 10% and 20% since their lows in September and we believe prices will continue to rally as yield estimates for both soybeans and especially corn are lowered again.

2019 has been marked by two extreme weather events: the 2019 spring floods in the upper Midwest and the near record October blizzard. Although we really don't know, we have a sneaking suspicion that both weather events are the first signs that the world climate is about to enter a sustained cooling phase that will be related to reduced sunspot activity. The long-term weakening of the 11-year solar sunspot cycle, a subject we have discussed in a previous letter, may already be impacting global weather in ways that will become more and obvious as the years unfold.

We believe the bull market on grains has started and will cause continued upward pressure on grain prices as grain yield assumptions are reduced and carryout estimates drop. We remain bullish on grain, and we believe investors should have significant exposure to agricultural related equities.

Authors Bios'

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Mr. Goehring has 25 years of investment experience specializing in natural resource investments. From 2005 until the end of 2015, Mr. Goehring was the portfolio manager of Chilton Global Natural Resources Fund. This dedicated natural resources focused hedge-fund grew to over $5 billion of assets under management at its peak.

Prior to joining Chilton Investment Company, Mr. Goehring served as the manager of the Prudential-Jennision family of natural resources funds between 1991 and 2005. These funds accumulated over $3 billion of assets under management at their peak.

Mr. Goehring started working on Wall Street in 1982 in the Trust Department of the Bank of New York. He holds a Bachelors of Arts degree with a major in Economics and a minor in Mathematics from Hamilton University.

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Mr. Rozencwajg has nine years of investment experience. Between 2007 and 2015, Mr. Rozencwajg worked exclusively on the Global Natural Resources Fund at Chilton Investment Company with Mr. Goehring.

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