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Goehring & Rozencwajg
Natural Resource Market Commentary

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THE DISTORTIONS OF CHEAP ENERGY

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The Distortions of Cheap Energy

We are making one of the largest mal-investments ever—possibly only rivaled by the one made by banks in mortgage-backed securities 15 years ago that ultimately produced the 2008 global banking crisis and financial panic.

Over the last decade billions of dollars have been diverted from traditional energy investment to so-called "transition technologies," notably wind, solar, and lithium-ion- powered electric vehicles. These technologies represent the worst of all possible worlds: not only do they generate inferior economic returns, but they are unable to address our carbon reduction needs.

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The analysis here is some of the most important work we have done in our 30-plus years of energy investing. It builds on several previous letters in which we discussed the energy efficiency of various renewable technologies and how those renewables unfavorably compare to hydrocarbon-produced energy. Please consider what we are about to discuss with an open mind; our conclusions are original, contrarian, and extremely important. as they are likely to result in massive unintended consequences, some of which have already emerged and are painfully obvious. For example, we believe the huge investments made in renewables over the last decade are responsible for the energy crisis that is gripping Europe today. Only a month ago natural gas prices in Europe hit $50 /mmbtu—or $300 per barrels in oil terms.

Investment crazes and major bear market bottoms are often caused by a single faulty assumption. In the early 1980s, stocks traded at decades-low valuations because everyone was convinced inflation was an intractable problem. The next four decades proved otherwise. In the late 1990s, stocks reached record high valuations as investors assumed traditional financial analysis was no longer important. Enterprise value per eyeball replaced price to earnings as a common metric. During the global financial crisis, the hyper-financialization of residential real estate was based upon the belief that housing prices could only rise. Once prices fell, the embedded leverage in the system became painfully evident to everyone.

Over the past decade, investments in "green" energy have dramatically surged in popularity. In 2020 alone, $700 bn was allocated to ESG-friendly investments. We believe that much of that investment is driven by faulty and poorly understood assumptions. Investors incorrectly believe that adoptions of new technologies have been the driving force in lowering the cost of renewable power. But what if we you told you that almost all the drop in renewable energy costs over the last decade came not from advances in technology but from lower energy prices? Just like cheap capital (in the form of low interest rates) leads to malinvestment in the financial world, cheap energy has now led to malinvestment in new technologies that are energy inefficient.

OVER THE PAST DECADE, INVESTMENTS IN "GREEN" ENERGY HAVE DRAMATICALLY SURGED IN POPULARITY. IN 2020 ALONE, $700 BN WAS ALLOCATED TO ESG-FRIENDLY INVESTMENTS. WE BELIEVE THAT MUCH OF THAT INVESTMENT IS DRIVEN BY FAULTY AND POORLY UNDERSTOOD ASSUMPTIONS.

Before we can properly assess the impact of cheap energy on renewable power generating costs over the past decade, we must appreciate the energy crisis currently unfolding. We first wrote about the coming energy crisis in our 2Q2020 letter – a controversial call given oil prices had modestly recovered after having turned negative for the first time in history. However, within a year, the energy crisis was upon us and it's now rapidly intensifying. Energy prices went from the lowest level in human history (oil trading at less than zero) to the highest level in human history (Asian imported LNG and European natural gas prices hitting $50 per mmbtu or $300 per oil-equivalent barrel) in a mere 18 months. The relentless energy price advance has forced industrial capacity curtailment in China and Europe, notably in energy intensive sectors like fertilizer production which we discuss in the Agriculture section.

High energy prices and worries over supply insecurity have also shifted the geopolitical focus. For example, Europe is watching Putin amass troops on Ukraine's border, acutely aware of their dependence today on imported Russian natural gas.

How did things change so quickly? While many people point to COVID-related disruptions, the truth is that the current energy crisis has been a decade in the making. For many years, demand has been much stronger than anyone cares to admit. We have long discussed our S-Curve model: once a country reaches a certain level of real per-capita GDP (around $2,000), energy demand begins to move sharply higher before plateauing once again around $20,000 per-capita GDP. Prior to this century, approximately 700 mm people were going through this period of accelerating energy demand at any given moment. In the early 2000s, this number surged and has continued to grow ever since. We now estimate over 4 bn people (50% of the world's population) is in or nearing the middle part of their S-Curve development. This resulted in much higher-than-expected energy demand almost every year since 2003.

FIGURE 1 South Korean S-Curve Oil Demand

Source: BP Statistical Review, World Bank.

At the same time, investors have starved the energy industry of capital. US E&P capital spending peaked in 2014 at $140 billion and has fallen ever since. Even before COVID-19, E&P companies were spending half the 2014 peak – approximately $70 bn. During the pandemic, companies slashed spending even more, eventually falling to $30 bn in 2020 – the lowest reading in decades and 80% below the peak. The average E&P stock between 2014 and 2020 fell by 90%.

Energy is a fundamentally cyclical business, driven in large part by a carefully choreographed capital spending cycle. Tight energy markets cause prices to rally. Companies generate supernormal profits and attract investor capital. The market rewards growth, incentivizing companies to use their new-found capital to drill more wells. Supply begins to grow and eventually exceeds demand. The cycle reverses itself as energy prices fall, corporate profitability collapses, stock prices decline, and capital flees the industry. Over time, depletion takes hold yet again, supply ratchets relentlessly lower, and the cycle repeat itself.

At present, the normal market/investment cycle is being hindered by outside forces that didn't exist previously. The emergence of climate concerns and related ESG has forced capital to flow out of the traditional hydrocarbon based energy and into renewables. .

After the 2020 massive COVID-related demand shock, the market by second half of 2020 slipped into deficit. Over the last 18 months, global oil inventories are at their lowest reading in 20 years. Oil prices have rallied to $90 (the highest level in eight years) while LNG reached $50 per mmbtu (an all-time high) and both oil and gas markets are backwardated (when future prices are below spot prices) signifying significant physical tightness. . Energy stocks rallied sharply and were the best performing sector of the market last year.

The market has clearly signaled the need for more investment in upstream production. However, capital spending budgets during this cycle have hardly budged. We estimate the

US E&P companies will only spend $45 bn in 2022 – up from the COVID low of $30 but far below even 2019's depressed level. The last time oil averaged $90 was 2014, a year in which E&P capital spending totaled $140 bn – nearly four times higher than we expect this year.

The market needs more supply, but the normal clearing mechanism is being blocked by ESG pressures. Engine No. 1 secured three Exxon board seats in May 2021, despite owning a mere 0.02% of the shares outstanding. The fund waged a public campaign urging Exxon to slash upstream capital investment. Fearing similar shareholder activism, most energy companies have diverted spending away from production and focused instead either on returning capital to shareholders or on funding renewable projects.

These activist investors believe traditional energy will soon be eclipsed by renewables, both in terms of economic returns and carbon emissions. They talk relentlessly about renewable power's declining costs and how someday renewables will compete with hydrocarbons in energy efficiency. They argue that this time really is different because of electric vehicles and that oil demand, after 160 years of relentless advances, will decline. They warn about the risk of hydrocarbon assets being "stranded as demand falters and investments made in long lived hydrocarbon asset such as oil sands will never be recovered. These activists argue that energy companies must stop spending on their upstream immediately or risk impairing their capital and instead must spend on renewable energy investments that will ultimately yield higher returns. They believe they are acting rationally in the face of changing technology, but what they really are doing is preventing the carefully choreographed energy capital spending cycle from taking place.

We firmly believe their analysis is seriously flawed and that 2022 will be the year that the flaws are exposed.

Let us explain Energy Return on Energy Invested (EROEI), an obscure but very important term, , that we expect to become one of the important buzzwords of the decade. EROEI measures how much energy is required to generate a useable unit of power. For example, for every unit of energy "invested" in the natural gas eco-system (to drill the well, process and transport the gas, build a CCGT power plant, and generate electricity), 30 units of usable power are released in the form of electricity. Natural gas power generation is said to have one of the best EROEIs at 30:1.

For most of human history, our energy systems were remarkably static. Most energy came from food and animal feed while wood (used for heat and as a building material) provided the balance. Energy historians estimate this mix of biomasses resulted in an EROEI of 5:1 – for each unit of energy in, you generated five units of energy out.

In AD 1, we estimate energy production averaged 17 gigajoules (GJ) per person annually. Assuming an EROEI of 5:1, 3 GJ were needed to supply this energy. Human food intake consumed 4 GJ of this energy, while other necessities like shelter and feeding your work animals consumed 10 GJ annually. Therefore, nearly all the 17 GJ of this energy produced per person was needed for daily sustenance. Less than 1 GJ in surplus energy was left after taking care of these needs.

Growth was impossible in such a system. Global population grew at a mere 0.02% per annum between AD 1 and 1650, not even doubling over the course of sixteen centuries. Total energy produced over that period went from 17 GJ per person to only 20 GJ or 0.04% per annum.

In the seventeenth century, the forests around London had been entirely cut. The amount of energy required to bring wood in from further afield required more energy than it was worth and so the population was forced to consider alternatives. Coal was abundant and turned out to be a very effective source of energy when burned. We estimate early coal-based steam power had an EROEI of 10:1, twice as productive as the biomass that had been used for thousands of years. To meet the 20 GJ of annual demand went from requiring 4 GJ of energy to less than 2 GJ. Human food needs were unchanged at 4 GJ and other necessities remained 10 GJ. Therefore, the surplus energy quadrupled from less than 1 GJ per year (unchanged for thousands of years) to 4 GJ per year.

The shift from biomass to coal and the resulting increase in surplus energy drove rapid growth. After having taken 1600 years to double, both population and total energy demand quadrupled over the next 250 years – a twenty-fold acceleration.

The next major advancement took place in 1900 with the widespread adoption of hydrocarbons. Both oil and natural gas enjoy extremely high EROEI of 30:1. Therefore, to generate per capita of energy demand 25 GJ took less than 1 GJ. Human food needs and other necessities remained unchanged at 4 GJ and 10 GJ respectively, leaving a 10 GJ surplus. Once again, growth accelerated dramatically, with energy production and demand surging 13-fold in only 120 years and population going from two billion to eight billion people. By 2019, global per capita energy production and demand averaged 75 GJ – three times greater than in 1900. It took 1650 years to go from 17 GJ to 20 GJ of energy supply, 250 years to go from 20 GJ to 25 GJ, and only 120 years to go from 25 GJ to 75 GJ. In the developed world, the acceleration has been even more dramatic. By 2019, OECD energy consumed was 175 GJ – seven times greater than in 1900.

This increase in economic growth was entirely driven by improving EROEI. The modern world we enjoy today is the direct result of efficient and abundant sources of energy. At the same time, increased carbon emissions have led to a huge movement to switch away from fossil fuels in favor of wind and solar. Unfortunately, the EROEI of both wind and solar are approximately 3.5:1 (after adjusting for intermittency and redundancy), in other words very close to the biomass-based energy system that existed for most of human history. We hope it is now clear why such a low-EROEI system would be incredibly painful to adopt. Surplus energy would be immediately slashed by 40% and, given its complete disappearance, economic growth would grind to a halt—we would re-enter the world that existed between AD1 to AD 1650.

FIGURE 2 Energy Return on Energy Invested

		Energy used for...				
Starting Energy Demand	**EROEI**	**Energy**	**Food**	**Other Basics**	**Surplus**	**Economic Growth**
75	15	5	4	10	56	~3%
	3	25	4	10	-39	0.04%
	-80%	*400%*			*-170%*	*-99%*

Source: G&R Models.

To understand why renewable energy has such a poor EROEI, consider the materials needed for a 1.5 MW windmill. The foundation alone requires 40 tonnes of steel and 600 tonnes of concrete. The tower requires another 150 tonnes of steel while the generator requires 9 tonnes of copper, the nacelle requires 45 tonnes of steel, and the rotors require 15 tonnes of carbon fiber. Since wind power is intermittent, a 1.5 MW windmill is expected to operate at a load factor of only 30%. That means a 1.5 MW windmill will produce 4 GWH of power per year over its 20-year assumed life. If we converted the electricity into barrels of oil equivalent (adjusting for the difference between electric and thermal energy), this 1.5 MW windmill would be equivalent to an oil well that ultimately recovered a mere 116,000 barrels – approximately 10% as much as the best Permian wells drilled today. In other words, it would take 10 windmills – each 100 m tall -- to replace the energy produced in a single Permian oil well.

Making matters worse, neither wind nor solar energy generate power when the wind isn't blowing or the sun isn't shining. In order to smooth the variability, additional capacity must be built (for small regional variance) and battery back-up must be installed (for longer duration buffering between day and night). Both of these solutions are incredibly energy intensive and dramatically reduce the EROEI even further.

MUCH OF EUROPE'S ENERGY CRISIS TODAY IS RELATED TO THEIR MASSIVE RENEWABLE INVESTMENT, ALL OF WHICH SPORTS AN EXTREMELY LOW EROEI.

Much of Europe's energy crisis today is related to their massive renewable investment, all of which sports an extremely low EROEI. The questions we get asked the most are: "how could renewables possibly have such poor EROEI without anyone realizing it, and how could so much renewable investment be made with so little recognition of the problem? Also, what underlying condition changed to expose this problem?

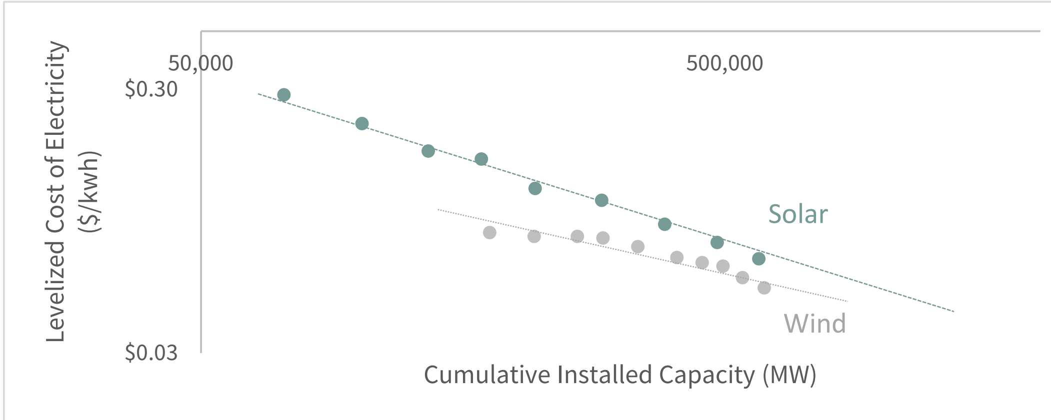
Our modeling suggests that declining (and cheap) energy prices have distorted and partially hidden the true costs of wind and solar over the last decade. Now that energy costs have surged, the true cost of installing and operating renewables are obvious. The relationship between energy input costs and the cost to produce renewable electricity is based upon our propriety research., We have not seen this argument laid out anywhere before, but the more we study the issues the more we're convinced we are correct.

The past decade has seen a material acceleration in renewable adoption. At the same time, from 2010 to 2020, every form of primary energy (oil, natural gas, coal, uranium) fell by nearly 90% from peak to trough. We have gone back for 150 years and cannot find a similar ten-year drop. According to Sydney and Homer, the 2010s also witnessed the lowest interest rates in at least 4,000 years. The 2010s were characterized by cheap, abundant energy and cheap, abundant capital.

Amazingly, no one has connected declining energy costs and cheap capital with the proliferation over the last decade of energy-hungry, capital-intensive projects such as wind, solar, and lithium-ion battery manufacturing. We think the two are fundamentally linked. What will happen when energy prices normalize and interest rates rise—as is happening right now? The impact will be far more consequential than anyone realizes.

Over the past decade, the levelized cost of electricity (LCOE) for solar has fallen by 80% from 40 cents per kwh in 2010 to 7 cents in 2019. Wind costs have fallen by 40% from 9 cents per kwh to 5 cents. Most investors believe this is due to the learning curve, whereby costs fall as cumulative installed capacity increases and technologies improve.

FIGURE 3 Solar and Wind Learning Curves



Source: IRENA.

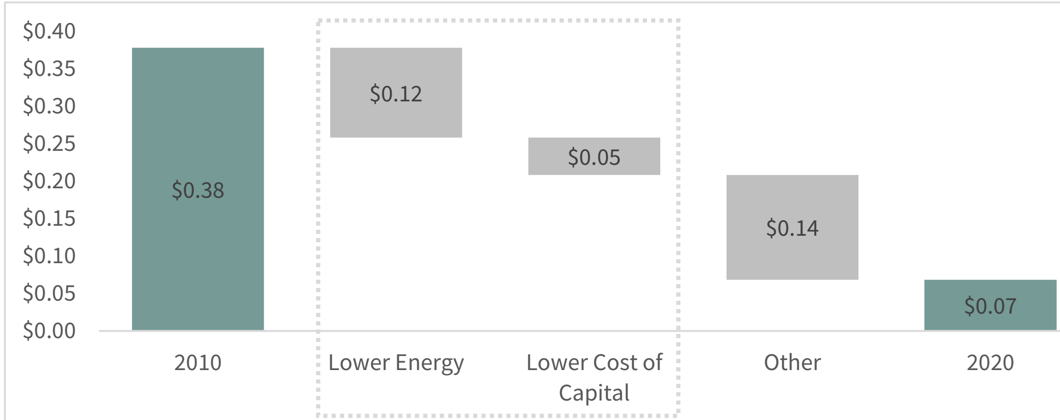
As you can see, costs have steadily fallen as more wind and solar capacity has been deployed. Policy makers have used this data to advocate for renewable energy subsides, arguing that subsidizing early investment in renewable will pay off as costs eventually fall to levels where renewables can compete with natural gas and coal. Unfortunately, the learning curve argument is not nearly as compelling after adjusting for the impacts of lower energy prices and interest rates.

For example, we calculate that half of the 33 cent drop in solar LCOE between 2010 and 2020 was the direct result of lower energy input and capital costs. Our models suggest it takes 100 GJ of thermal-equivalent energy to manufacture and install 1,000 W of solar capacity. Between 2010 and 2020, energy prices fell from approximately $14 per GJ ($80 per oil-equivalent barrel) to $2.80 per GJ ($20 per oil-equivalent barrel). The total direct cost of energy fell by over $1,000 per installed kw---from $1,400 to less than $300, representing more than 10 cents of the 33-cent total LCOE drop. The assumed cost of capital fell by one-third from 7.5% to 5.0%, resulting in another 5 cent drop. Furthermore, the commonly chosen 2010 starting point for solar is misleading, as it incorporates artificially high starting polysilicon prices due to a short-term supply chain shortage. We estimate this likely accounts for another 5-10 cents in LCOE reduction over the past decade. Therefore, 20-25 cents of the 33 cent total reduction in solar costs are directly attributable to lower energy prices, lower costs of capital, and one-time distortions in the polysilicon markets. Between 60-75% of the cost saving attributed to the so-called learning curve can be explained away by these three factors.

Wind power tells a similar story. Between 2010 and 2020, the LCOE fell by 9 cents to 4.5 cents per kwh. We estimate that lower energy costs and capital costs represented 50%-70% of the cost savings. We suspect our analysis could be too conservative.

It is no coincidence that the proliferation of renewable energy occurred during a decade of abundant cheap energy and abundant cheap capital. As both resources become scarcer and more expensive, the inherent limitation of renewable energy (i.e., its significantly worse EROEI) will come to the fore. Our view is extremely out-of-consensus. In fact, most investors believe low energy prices have severely discouraged the adoption of renewable energy. When we ask what impact rising energy prices will have on renewables, the vast majority argue that higher energy prices will help renewables by making them more cost competi-

FIGURE 4 Solar Costs Over Time



Source: NREL, Weissbach, IRENA, G&R Models.

tive. Most investors are under the impression that much higher energy prices will push renewables "into the money"--- that is renewables will become competitive for the first time versus higher priced hydrocarbons. This completely ignores the fact that energy itself makes up the single largest cost component for both wind and solar. Instead of making renewable energy more cost competitive, higher energy prices will simply drive up the costs. Renewables today remain "out of the money" and higher energy prices will never be able to push renewables "into the money."

Proving just how energy sensitive renewable components are, coal prices surged by 100%, and Chinese polysilicon prices (the main component of solar modules) jumped 300% in Q4of 2021. Also, Bloomberg New Energy Finance (BNEF) recently published their 2022 lithium-ion battery projections and indicated that prices would likely rise for the first time in a decade – something nobody thought possible only a few months ago. We disagree. with BNEF's argument that the rising price is likely transitory owing to supply chain disruptions. Lithium-ion battery manufacturing is extremely energy intensive and it's our belief that higher energy prices likely drove the cost increase. (Back in 2018 we argued that lithium-ion battery costs would likely plateau after a decade of steady declines – please click here to read more.)

IF OUR MODELS ARE CORRECT AND BOTH ENERGY PRICES AND CAPITAL COSTS RISE GOING FORWARD, THE IMPACT ON RENEWABLE ENERGY WILL BE DRAMATIC.

If our models are correct and both energy prices and capital costs rise going forward, the impact on renewable energy will be dramatic. We calculate that solar costs could easily rise from 7 cents to 20 cents per kwh while wind costs could rise from 4.5 cents to 6.0 cents per kwh. In both cases, nearly a decade of cost savings would be wiped out.

EROEI is not some abstract academic concept; it has huge impacts on a country's economy and its ability to grow. Germany, after the Fukushima nuclear accident, decided to close all of its nuclear power plants. Nuclear power plants have the highest EROEI of any energy source (100 : 1) and nuclear power supplied almost 25% of Germany's electricity. Much of the nuclear generated power was replace with renewables with EROEI's of only 3 : 1. To any observer, there should be no mystery about why German electricity prices have surged by over four-fold in the last two years and why Germany is at the center of Europe's energy crisis—it's what happens when you replace an energy source with incredibly high efficiency with an energy source embedded with low efficiency.

To maintain our standard of surplus and allow for growth, we must adopt an energy system with a superior EROEI. Nuclear energy enjoys an EROEI of 100:1, three times better than hydrocarbons and 30 times better than renewables. Moreover, it has extremely low carbon intensity. A widespread move towards nuclear power could be as valuable to humanity as moving from biomass to coal was in the sixteenth century. The uranium section discusses the rapidly changing attitude, especially in Europe, of the advantages of nuclear power.

Renewables promise much, but because of the terrible energy efficiency, they will never be able to accomplish their goals of suppling cheap, abundant, and carbon-free power to a world that still wishes to grow.

Natural Resource Market Commentary -- 4thQuarter 2021

Global commodity markets reacted in mixed fashion to the new Omicron COVID -19 variant which took the world by surprise in Q4, again threatening disruptions to the global economy.

Oil prices rose slightly during Q4. US WTI prices were flat; Brent prices rose 2%. For the year, oil prices rose 55%. We believe oil prices are about to move significantly higher as we progress through 2022. As was the case with natural gas, the crisis emerging in oil will come of nowhere and catch everyone by surprise. This letter's oil section goes into detail on how underlying fundamentals are pushing the global oil markets into crisis. This includes the first installment of our research on the spare-capacity issue that is now sparking debate among global oil analysts. A significant number of OPEC+ countries are already demonstrating they cannot produce their quotas, let alone their full stated pumping capability. We start by discussing how Russia's potential supply growth (or lack thereof) will impact OPEC+ behavior this decade.

North American natural gas prices pulled back 35% to finish the year at $3.75, as December's weather was significantly warmer than normal. International natural gas prices went for a wild ride in Q4. After starting the quarter at $26 per mmbtu, European natural gas prices proceeded to spike to over $50 per mmbtu (or $300 per barrel in oil equivalent terms) in response to a cold start to winter and continued constrictions in Russian gas supply. After reaching a peak only days before Christmas, prices collapsed after Russia promised more gas deliveries and weather forecasts predicted warmer than normal temperatures for Europe's remaining winter. European natural gas prices finished Q4 at $20 per mmbtu, down 30% from the quarter's start; however for the year natural gas prices in Europe soared over 300%, making it the best performing commodity market in 2021. Asian gas prices followed European prices, soaring to over $50 per mmbtu in December, before collapsing at year end and ending at $33 per mmbtu-or just shy of $200 per barrel when expressed in oil terms. US gas prices have now pulled back as well because of the 10% warmer-than-normal start to winter, resulting in swings to US natural gas inventories from a 5% deficit on October 1st to a 5% surplus at year end. Natural gas analysts have also been concerned about a recent uptick in US natural gas production, but we believe this will be mostly short lived, driven by one-time DUC (drilled but uncompleted wells) liquidation. Also, demand for US natural gas will get another boost from expansions to both Mexican pipeline, and LNG export capacity. We remain extremely bullish towards natural gas and believe that the weakness in today's gas price and related natural gas equities have given investors another opportunity to add to their positions.

After surging in Q3, global coal prices treaded water in Q4. Powder River Basin coal prices were the exception—they surged by over 125%. Responding to last fall's big run-up in natural gas prices, utilities switched from burning natural gas to much cheaper PRB coal, causing PRB price to surge. . For those with an interest in the coal space, we wish to highlight the cheapness of coal related equities; however, as we discussed in our last letter, we continue to watch global coal market from the sidelines.

Precious metals markets showed some firmness in Q4. Gold and silver prices rose 4% and 6%, respectively; platinum and palladium prices were flat. Gold stocks as measured by the GDX ETF advanced 11%; silver equities, as measured by the SIL ETF, advanced 6%. On the whole, 2021 was a down year for all precious metals and their related equities. Gold prices fell over 3%, silver prices fell 12%, and gold and silver equities fell 10% and 18%, respectively. We do not believe the period of price consolidation for precious metals has run its course yet; however, there are a number of underlying demand trends suggesting that the period of price consolidation is approaching an end. Also, we can't help but notice the extreme-low valuations now being sported by most precious metal equities. The precious metals section of this letter discusses the return of central bank demand and the measurable slowdown in the liquidations of physical gold and silver investments by western investors. For anyone with long-term investment horizons, we continue to recommend significant investment exposure to both physical gold and silver, as well as their related equities, as we remain highly confident that another massive bull market awaits. For those with short-term performance constraints, we believe it still pays to sit on the side-lines.

Base metals had upside biases during Q4 as well. Zinc and nickel prices advanced over 15%, aluminum, after surging in Q3 pulled back 2%, and copper, which remains our most favored base metal, advanced 9%. Base metals related equities, as measured by the XBM Base Metals ETF, which mirrors the S&P global base metals stock index, rose 14%. Copper equities, as measured by COPX copper stock ETF, rose 9%. We just returned from Riyadh where we attended the first "Future Minerals Forum" hosted by the Saudi Arabian government. The Saudis have now opened up their mining industry for the first time ever to foreign companies and the conference was centered on the tremendous mining opportunities in the Saudi Kingdom. The conference also included a number of presentations that discussed the huge global imbalances now emerging in various metals markets. Many presentations discussed how surging demand is now colliding against a mine supply that refuses to grow, a subject we have discussed at length in these letters. Three years ago, few market participants—either investors or mining executives-- fully grasped the strength and persistence of these trends especially in copper. Now, they are being forced to. The CEO of one of the world largest gold producers admitted at the conference that if he could do the last 10 years all over again, he would have turned his company into a copper company. We remain bullish on copper and recommend investors maintain significant exposure to copper focused equity investments. The copper section of this letter explains the current fundamentals.

Uranium prices were flat during the quarter and large cap uranium producers such as Cameco and Kazatomprom pulled back slightly after their big price runs in Q3. The short-term supply demand trends in global uranium continue positive and we are firm believers that uranium prices will surge again at some point in 2022. The advantages of electricity generated from nuclear fission versus renewable power are become more recognized. As this trend continues, we expect nuclear sentiment to improve and asset values to rally. Please read the "Uranium and Nuclear Power" section of the letter, where we discuss the recent developments. We continue to recommend that investors maintain large exposure to uranium related investments.

Global grain markets were mixed in Q4. Corn pulled back 9%, but both soybeans and wheat advanced 6%. Grain markets loosened slightly as corn yields, as predicted by our neural network modelling, failed to pull back. In their August 2021 World Agricultural Supply and Demand Survey (WASDE), the USDA slashed their US corn yield estimates from 179.5 bushels per acres to 174.6, very much in line with the prediction made by our neural network a month earlier. Since then the USDA has nudged their corn yield assumption back to the 177 level-a full 4four bushels higher than the 173 bushel prediction we made in our Q3 letter. Higher yield assumptions have pushed 2021-2022 corn ending stock up from 1.23 bn bushels to 1.55 bn bushels—still tight, but not as tight as previous predictions. In soybeans, little has changed in the last three months. The USDA has kept yields --51.4 bushels per acres--and ending stocks--350 mm bushels-- very close to their September WASD estimates. Ending stocks have now normalized which has taken significant price pressure off both grains. Corn and soybean prices are now almost 20% off their May 2021 highs. Wheat continues to move higher on booming global demand. Wheat demand in 2021 has surged by 5% versus 2020. As expected, all the increase occurred in emerging market economies, with China and India leading the way.

Fertilizer prices continue to move higher, given fertilizer's large energy input intensity and the global crisis in natural gas. Nitrogen prices advanced another 20% in Q4, phosphate price advanced 11%, and potash prices advanced 7%. Except for Asian and European natural gas prices, fertilizers were among the best performing commodities in 2021:urea prices (a solid form of nitrogen) and potash prices advanced 210% and 180%, respectively. Already stories are beginning to emerge regarding fertilizer shortages, especially in the nitrogen complex. In the agricultural section of the letter, we discuss how the intensifying problems in global fertilizer markets might impact the 2022 planting season.

Even though the extreme tightness in global grain markets has faded, the underlying forces pushing grain prices higher over the last two years have not receded. In the agriculture section of this letter, we will discuss why the recent period of very strong grain consumption growth is nowhere near over.

On the supply side, we believe the extremely favorable crop growing conditions experienced over the last 30 years could very well be changing--- with huge implications. The consensus opinion continually presses the point that global warming and climate change will bring forth near apocalyptic conditions to the world's grain belt. We firmly believe that global warming trends over the last 30 years have been the only way the world could accommodate a 75% jump in grain demand. Although no one wants to admit it, global warming has fostered propitious growing conditions which has enabled crop yields to steadily increase upwards. In our next letter we will discuss how warming climate trends over the last 30 years have created near perfect growing seasons in many parts of the world. Yet, we believe we have now entered a long-term cooling cycle, which will severely crop hinder the huge increase in crop yields experienced over the previous decades.

Strong demand is colliding with weather related supply problems as we speak, and we continue to believe we are slipping into a global agricultural crisis. We remain extremely bullish toward agricultural related equities and recommend investors maintain sizable exposure, especially to the fertilizer producers.

The OPEC Spare Capacity Issue Part 1: The Russian Dilemma

"OPEC + Supply Shortfall May Push Oil Price Higher, IEA Warns" Bloomberg, February 11th, 2022

"OPEC + faces chronic struggle to meet output target, IEA" Bloomberg, February 11th, 2022

We have always been big believers that OPEC's spare capacity has been significantly overstated. As late as 2015 consensus opinion believed OPEC could pump over 37.5 mm barrels per day if necessary. Between 2010 and 2015, OPEC pumped, on average, a little over 30.5 mm b/d, meaning that OPEC could marshal, if need be, an additional 7 mm b/d of oil production in any given year. Since 2015, OPEC's total pumping capability has slipped considerably. Today, OPEC's total pumping capability is estimated to be just 33.8 mm b/d, down almost 4 mb/d from the 2015 peak. When OPEC's oil production returns to the 30 mm b/d level, which should happen at some point this summer, OPEC's spare pumping capacity will be down to only 3.8 mm b/d— 50% lower than 2015 levels. In a world where global oil demand is now running over 100 mm b/d, this 3.8 mm b/d of spare capacity represents a dangerously small cushion.

The table below clearly shows the significant decline that has taken place in OPEC's spare capacity over the last five years.

PRODUCTION PROBLEMS WITHIN THE OPEC PRODUCING BLOCK ARE ALREADY SHOWING UP AS WE WRITE.

Production problems within the OPEC producing block are already showing up as we write. For example, OPEC's actual production in December fell almost 500,000 below their stated December quotas . 100% of this underperformance comes from Angola and Nigeria; however, we believe other production disappointments by big OPEC producers, including Russia, will follow as we progress through 2022. For example, in past letters we outlined how it would be extremely difficult, if not impossible, for the Saudis to grow their production above 10.5 mm barrel per day for any sustained period. Saudi Aramco still claims to have 12 mm b/d of pumping capability. They talk about boosting their long term pumping capability to 13 mm b/d, but based on their 2018 release of audited reserves data--the first release of such data in almost 50 years-- we believe their old 12 mm b/d figure will be almost impossible to reach, let alone this new 13 mm b/d target.

In a series of upcoming essays, we will discuss how the geological and social political constraints confronting various OPEC (and OPEC+) producers will potentially impact their ability to actually reach their stated pumping capabilities over the next two years. OPEC states they still have 33,8 mm b/d of pumping capability, and assuming they produced 30 mm b/d in 2020, this means that spare pumping capability is only 3.8 mm b/d. Small as this figure is, we believe that it's still significantly overstated.

FIGURE 5 OPEC Spare Capacity

	2015	2020	Change
Venezuela	2.8	0.6	(2.2)
Saudi Arabia	12.5	12.0	(0.5)
Nigeria	2.4	1.6	(0.8)
Angola	1.9	1.2	(0.7)
Kuwait	3.2	2.7	(0.5)
Libya	1.5	1.2	(0.3)
Algeria	1.2	1.1	(0.1)
Iran	3.8	3.8	--
UAE	3.4	4.2	0.8
Iraq	3.7	4.8	1.1
Congo	0.3	0.3	--
Equatorial Guinea	0.1	0.1	--
Gabon	0.2	0.2	--
Total	**37.0**	**33.8**	**(3.2)**
Average OPEC Production 2000-2019	30.0		
Spare Capacity	**7.0**	**3.8**	

Source: IEA.

Our OPEC pumping capability discussion will begin with a country that is not even a member of OPEC—Russia. Over the last 7 years, Russia has become a quasi member"and its short-term history with OPEC's most important member --Saudi Arabia--- has already turned problematic. We believe the Russian oil industry could very well have huge impacts on OPEC's behavior going forward.

Russia's deep OPEC involvement began in earnest seven years ago. After OPEC's November 2014 meeting failed to produce any production cuts, the Saudis instituted a full scale market share war with two goals: to stop the production growth of the US shales and to reduce the oil revenue being used by Iran to fund its expanding influence across the Middle East. By Q1 of 2015, the Saudis had boosted their production by over 1 mm b/d. In response to surging OPEC supply, oil prices collapsed over 60% from their 2014 highs . Scared by the relentless price decline, Russia—who had attended the November 2014 OPEC meeting---and other assorted non-OPEC nations (now known as OPEC +) agreed in the summer of 2015 to cooperate with OPEC to reduce production, lift prices , and shore up sagging government revenues. Russia had half-heartedly cooperated with OPEC production cuts in the past: in 1998, 1999, and 2001, but those cuts back then were small, and its compliance with those production cuts non-existent. After agreeing to the 2015 production cuts, Russia made known that it had little interest in further collaboration with OPEC. What Russia wanted and what the Saudis desired were not aligned and the schism between the two huge oil-producing countries became obvious after the COVID-19 pandemic began severely impacting global oil markets. In response to collapsing demand, the Saudis again approached Russia in March of 2020 and requested its cooperation in reducing production—a request that Russia rejected. In response to this rejection, the Saudis initiated a vicious price war with the intent of bringing the Russians back to the negotiating table.

With demand collapsing, the last thing the oil world needed was a boost of 25% from the world largest oil producer, but that's what the oil world got. The Saudis were ultimately successful in bringing Russia and the other OPEC+ nations back to the OPEC production cut table, but at a tremendous cost. With OPEC supply surging and global demand collapsing, global oil storage threatened to overflow. On April 20, 2020, a day for the record books, the NYMEX oil futures contract closed at -$37 per barrel.

IF RUSSIA IS IN A POSITION TO SIGNIFICANTLY INCREASE ITS PRODUCTION, IT'S NOT INCONCEIVABLE THAT WE COULD SEE MULTIPLE PRICE WARS BREAK OUT AGAIN BETWEEN THE SAUDIS AND RUSSIA.

Given the incredibly damaging actions undertaken by the Saudis in response to Russia's reluctance to follow OPEC production cuts in March 2020, we thought it critical to understand the growth potential for Russian oil production this decade. If Russia is in a position to significantly increase its production, it's not inconceivable that we could see multiple price wars break out again between the Saudis and Russia.

Last decade, it was US shale oil production which put OPEC and Saudi Arabia in a market share defensive position. This decade, many oil analysts believe Russia could very well replace US shales as the disruptive force in oil supply. Given the huge arctic oil discoveries made by Rosneft over the last 10 years, many believe Russia can significantly boost oil production by 2030, thereby again incurring the wrath of the Saudis, especially now that Russia is partially living inside the OPEC world.

Russian oil production has been on a rollercoaster over the last three decades. From the early 1970s to the late 1980s, the Former Soviet Union (FSU) structured its oil industry to maximize oil production at the expense of proper reservoir management technique, which resulted in massive field reservoir damage and billions of barrels of stranded and by-passed oil, especially in the massive oil reservoirs of western Siberia.

Russia's oil production peaked in the late 1980s at 11.5 mm b/d and then proceeded to collapse in lock-step with the demise of the FSU with oil production finally bottoming in 1999 at 6.1 mm b/d---a decline of over 45% from peak.

By the late 1990s, the Russian oil industry had been completely reorganized, much of it now under private control. Leading companies such as Yukos began bringing in teams of western trained petroleum engineers and geologists to aggressively introduce proper reservoir management and drilling techniques into the great, but severely damaged, western Siberian oil fields. The results proved to be incredibly successful. Back in the early 2000s, I spent several days with Yuko's reservoir management teams at their western Siberia headquarters and I was amazed by much stranded oil Yukos had begun to recover using standard western field management tools such as seismic, infill drilling, and proper water flood management.

Between 2000 and 2010, oil production rebounded by over 4 mm barrels. By 2018, Russia's oil production had finally surpassed its old 1989 high of 11.5 mm b/d. Few investors know that almost all of Russia's production rebound experience over the last 25 years came not from new discoveries, but from the recovering of the huge amounts of oil left stranded by old style Soviet reservoir management techniques. Also, many believe production growth can continue far into the future based primarily on this "brownfield" development (i.e., the exploitation of old damaged reservoirs); however, evidence continues to mount suggesting that "brownfield" development, which has provided almost all of Russia's oil growth over the last 20 years, has now come to an end. Between 2010 and 2019, production grew by only 1.6 mm b/d, down 60% from the previous decade.

The Energy Information Agency (EIA), the data arm of the US Department of Energy, in their December 13, 2021 "Country Analysis Executive Summary: Russia" states: "Declining output from Russia's more mature fields (primarily in Western Siberia, Russia's largest oil producing region) may offset the production growth coming from greenfield developments, which may result in Russia's crude oil production declining by the end of the 2020s decade."

Oil production in Russia today is extremely concentrated. Five publically traded companies are responsible for over 80% of Russia's oil production: Rosneft (at 40%), Lukoil (at 15%), Gazprom (at 11%), Surgutneftegas (at 11%), and Tatneft (at 5%). Between 2010 and 2019 (we stopped in 2019 as 2020 is distorted by the OPEC+ production cuts), these five companies increased their production by almost 1,000,000 mm b/d and represented over 60% of Russia's total increase in oil production. Looking at the breakdown of this 1 mm production growth, it important to note that almost 100% of this production growth came from Rosneft (pro-Forma the 2012 TNK acquisition) with little net production growth from the other four companies. In other words, one company—Rosneft, was responsible for 60% of the Russia's production growth between 2009 and 2019.

Although production continued to grow last decade, an interesting and overlooked trend has emerged in the reserve replacement trends of these five companies which we believe provides big clues to the direction of future Russian oil production.

Looking more closely at reserves, the five major oil producers are again responsible for all the growth in Russian oil reserves over the last decade. According to the BP Statistical Survey, between 2009 and 2020, Russian oil reserves grew from 106 bn barrels to 108 bn barrels. In that time, these five companies grew their reserves by 8 bn barrels, and again Rosneft (pro-forma the 2013 TNK/BP acquisition) represented 50% of this gain: 4 bn barrels. Outside of these five companies, the reserves of the remaining Russian oil industry look to have fallen by as much as 6 bn barrels.

It's important to note all reserve growth took place between 2010 and 2013. Since then, these five companies have failed to replace their production with new reserves. Between 2010 and 2013, these five oil companies replaced over 178% of their production with new reserves. Reflecting this stellar reserve replacement, the reserves of these five companies grew from 68 bn barrels of oil reserves in 2010 to over 80 bn barrels in 2013. Beginning in 2013 however, these figures began to slump significantly. Reserve replacement between 2013 and 2020 averaged only 92%. Reflecting the slumping reserve replacement ratio, reported oil reserves between for these five companies showed actual declines. In 2013, these five companies had 80 bn barrels of liquid hydrocarbon proved reserves--- by 2020, these reserves had fallen to 78 bn barrels. Rosneft and Lukoil, the two biggest oil companies in Russia, clearly show this reserve replacement problem. Between 2010 and 2013, Rosneft was able to replace 245% of its productions with new reserves (reserves are again adjusted pro-forma for the 2013 TNK/BP acquisition) which grew form 23 bn barrels in 2010 to 31 bn barrels in 2013. Between 2013 and 2020, however, Rosneft's reserve replacement fell to only 77%--meaning that Rosneft's proved reserves fell by 10% or by 3 bn barrels. Lukoil exhibited the same reserve replacement problem. Between 2009 and 2013, Lukoil replaced 90% of its oil production with new reserves; between 2013 and 2020, Lukoil's reserve replacement ratio had fallen to only 75%. Lukoil's oil reserves declined only slightly between 2010 and 2013, (from 13.4 to 13.3 bn barrels); reserves by 2020 had fallen to 11.7 bn barrels--down a significant 13%.

Although Russia's oil production keeps creeping up, the significant decreases in reserve replacement give us a strong signal that Russia's oil production growth based on "brownfield" development is slowing rapidly, and that production may now have entered a period of actual decline.

Recent production data released from the Russian Oil Ministry could also be confirming production problems. The Oil Ministry reported that producing wells taken off-line (in order to comply with the 2020 OPEC+ production cuts) are now being aggressively returned to production. After big increases in producing well counts for both November and December, the number of off-line producing wells brought back in production has now rebounded to levels not seen since 2017. Yet Russian oil output in December and now into January has not responded. Russia is currently producing almost 100,000 b/d below its OPEC+ quota. Many analysts have blamed cold weather and related well freeze-offs for the production disappointments over the last two months and the Russian oil ministry has stated that it expects to bring back oil production to it pre-COVID levels—11.6 mm b/d, up from 11.0 mm b/d today--by early as May of this year. However, if we see no further additions to producing well counts and production increases remain subdued, then it's not inconceivable that Russia's oil production could fall as much as 300,000 b/d below their OPEC+ quota by this summer. We will be watching Russian's oil production closely in the next couple of months to see if we see any rebound in production.

If the era of "brownfield" reserve replacement and production growth has now passed, and if the Russian oil industry is to avoid production contraction this decade, then oil production growth must come from the significant development of completely new greenfield projects. Which bring us to the most important new greenfield development project by far in Russia since the discovery of the great western Siberian oil fields and the great polar gas fields in the 1960's: the Vostok oil fields.

Discovered within the last decade, the fields making up the Vostok oil project are located on the Taymyr Peninsula, several hundred miles north of the Arctic Circle. The fields within the Vostok project are grouped in four big clusters and are estimated to contain as much as 50 bn barrels of recoverable crude. Given its remote location and extreme weather, the Vostok oil project will require massive capital investment in infrastructure before production can begin. Rosneft, the owner/developer of the Vostok project, estimates that the project will require building 15 new artic towns housing an estimated 400,000 workers, two airports, a new seaport, new electricity generating capacity of 2,000 MW, 2000 miles of new electricity lines, 4,000 miles of infield pipeline infrastructure, and over 500 miles of new pipeline export capacity. The project will also include the building of 50 new crude carrying ships including 10 advanced ice-class tankers that will be used to ship crude via the evolving "Northern Route"—the new northern arctic shipping lane that will bring crude from the Vostok project to Asia via the Arctic Ocean during ice free months. The capital costs of the Vostok project are estimated to be over $170 bn—a staggering figure. Complicating the Vostok financing issue are US sanctions placed on Russia (these are the sanctions put in place long before the recent Ukrainian tumult), which preclude any investment or operational participation by US companies. Rosneft has recently sold 15% of the project to oil traders Trafigura and Vitol, and rumors suggest that a consortium of Indian oil companies have quietly bought stakes. Also rumors continue to swirl that a potential large investment --with associated off-take agreements—will be made by the Chinese government and their related national oil companies, but as yet no announcements have been forthcoming. According to Rosneft, construction on various part of the project has already started, including the construction of the arctic seaport needed to export crude to via the Northern Route.

Rosneft estimates the Vostok project should be producing 600,000 barrel per day by 2024, 1 mm by 2027, and up to 2 mm b/d by 2030. Some energy analysts believe that Vostok's production will boost Russia's total production to well over 13 mm barrel per day (and possibly by much more) by the end of this decade. However, we believe that this figure fails to incorporate the rapidly accelerating depletions rate now gripping Russia's legacy oil production, as hinted in the EIA statement above, and confirmed by our analysis.

The importance of accelerating depletion and its underappreciated impact on Russian production this decade is extremely important. Assuming that the Russian oil industry can maintain its 92% reserve replacement—the actual reserve replacement experienced by the five publicly traded companies between 2013 and 2020---and assuming that the industry maintains its 25 year reserve-life index (the average over the last 10 years), Russia's base production will drop approximately 1.3 mm /d between 2019 and 2030. If the massive Vostok project eventually produces 2 mm b/d by 2030, then 65% of this 2mm b/d of new production will be offset by existing field depletion. If our analysis is correct, Russian 2030 oil production could reach 12.3 mm b/d by 2030 (up 700,000 b/d from the 11.6 level reached in 2019), but further production growth would be very difficult to achieve. If the Russian oil industry reserve replacement rate falls to 80%, (and remember the reserve replacement experience for both Rosneft and Lukoil are today significantly below this level), then we estimate that Russia's base decline in oil production will approach 1.7 mm b/d, which will largely offset Vostok's 2mm b/d of production growth. And if the reserve replacement falls below 80%, depletion from existing production will more than offset 100% of Vostok's estimated production growth. Russia's oil production will decline this decade even with all the production growth coming from the Vostok project.

The tension between the Saudis and Russia exploded in 2020 after Russia made clear that it had no wish to participate in OPEC's COVID-19 related production cuts. The disastrous decision made by the Saudis to wage a price war just as oil demand was collapsing produced the first recorded negative oil price in history. Given the Saudis desire to keep Russia in the OPEC fold, we would expect to see potential tensions re-emerge if Russia's oil production began to surge this decade. Just as they did in 2020, the Saudis could force production compliance from Russia, using OPEC's spare capacity as a weapon, especially since Russia has yielded to this strategy once before. Given the lack of production growth expected from Russiaa this decade, the danger of future price wars between Saudi Arabia and Russia has been significantly reduced, we believe.

In future letters we will discuss the issue of potential problems in spare capacity in other OPEC countries. Our modelling strongly suggests total global oil demand will consume this spare capacity by Q4 of this year and this assumes that OPEC can pump 33.8 mm barrels if need be. If we are correct, we will need all the pumping capability – but is it there? Stay tuned.

The Oil Crisis Unfolding in Slow Motion

"The world has already passed 'peak oil' demand, according to Carbon Brief analysis of the latest energy outlook from oil major BP." Carbon Brief, September 2020

"IEA Boosts 2022 Crude Demand Forecast, Says Consumption Could Reach Record Level" Natural Gas Intelligence, February 2022

"Some analysts have said that by the middle of the year unused capacity could be depleted." Reuters, January 2022

How could so many people get it so wrong for so long?

As we go to print, the International Energy Agency (IEA) has just announced the largest set of upward demand revisions in its history. For several years, we have discussed how the IEA chronically underestimates demand; these revisions suggest we were right. Despite the significance of the shift, most people were not even aware it took place. After a full decade of investor apathy (or outright hostility), it is difficult to change people's minds.

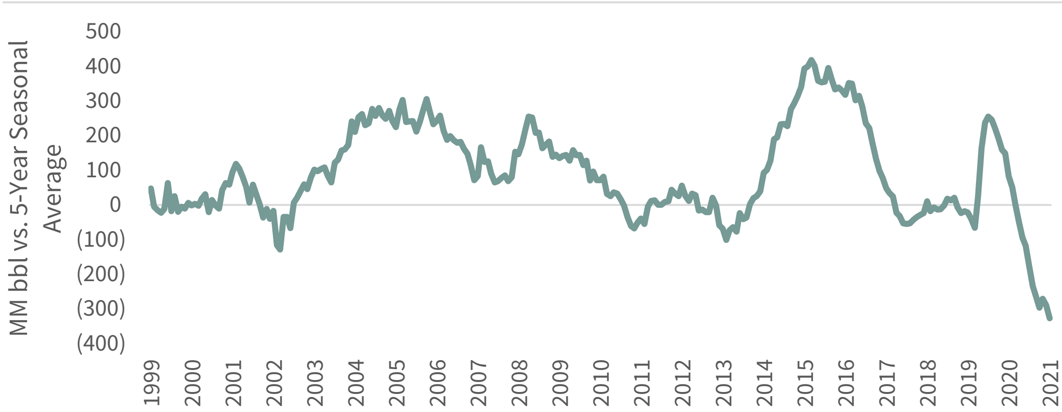
WHAT FOLLOWS IS A STUDY OF UNINTENDED CONSEQUENCES AND THE IMPACTS OF MASSIVE CAPITAL DISTORTIONS. FOR NEARLY A DECADE, THE ENERGY INDUSTRY HAS UNDERINVESTED IN ITS UPSTREAM BUSINESS; IT WAS NAÏVE TO THINK THIS WOULDN'T HAVE ANY IMPACT.

What follows is a study of unintended consequences and the impacts of massive capital distortions. For nearly a decade, the energy industry has underinvested in its upstream business; it was naïve to think this wouldn't have any impact.

Oil prices stand at eight-year highs and we believe they are heading higher. How high could crude rally in this cycle? We would not be surprised if prices ultimately spiked to between $150 and $200 per barrel. Natural gas prices reached $300 per oil-equivalent barrel in Q4, and the fundamentals in the oil markets are as bullish, if not even more so.

Volatility will likely increase as well. Global inventories are at their lowest seasonal levels ever, leaving us extremely vulnerable to any supply disruption, just as geopolitical turmoil seems to be accelerating. OECD inventories peaked in the summer of 2020 at the height of COVID lockdowns at 4.8 bn barrels – 245 mm barrels more than normal for that time of the year. Inventories are currently down to 4.1 bn bbl – 327 mm barrels less than normal for this time of year. Relative to seasonal averages, oil inventories have never been lower in our dataset going back to 1995.

FIGURE 6 OECD Oil Inventory vs. Five Year Seasonal Average



Source: IEA.

The headlines make it seem as though the current situation was entirely unforeseeable, but our readers know otherwise. In fact, most astonishing to us is how the current deficit unfolded in slow-motion over two years, receiving no attention from either investors or policymakers along the way. Oil prices have been rising steadily since April 2020 with only minimal short-term pullbacks. Nearly that entire time, the market has remained at near-record "backwardation" (future prices below spot prices); a key clue that physical markets were extremely tight. Inventories have been sharply and steadily declining for nearly two years. We estimate the oil market has been in outright deficit now since 2020 by over 1 mm b/d – the most pronounced and most sustained deficit in history. The fundamentals that led to the current deficit (strong demand and lack of capital spending) have been in place for over a decade.

Why were so few people prepared? Even now we do not think most investors understand the gravity of the situation. Things are about to go from bad to worse yet the energy weighting of the S&P 500 is lower today than it was when COVID was first spreading in the beginning of 2020. Energy stocks make up 3.4% of the S&P 500 compared with 11% in 2014 (the last time oil prices were this high) and the record-high 33% set in 1980.

FIGURE 7 Energy as Percent of S&P 500

Source: Bloomberg..

Whether you look at absolute prices, the backwardation, producer stock prices or inventory levels, all the normal market signals are screaming for more oil. This in turn requires more upstream capital spending. Unfortunately, ESG pressures are serving as a block, preventing capital from entering the oil market and preventing it from balancing. There is little relief in sight. Capital spending at the 100 largest energy companies in the S&P 500 topped out at $228 bn in 2014 and had already fallen by a third to $155 bn in 2019. The COVID-19 pandemic drove capital spending budgets lower by another 40% in a single year to $91 bn in 2020. With oil prices nearing $100 per barrel, energy capital spending is only expected to reach $98 bn in 2022 and $110 bn in 2023 – half the levels in 2014 the last time oil was above $90 per barrel. Companies talk about how they are listening to their investors and not investing capital in their upstream business. Clearly the market is not acting as though there is an acute oil shortage.

Today's situation is the result of years of vehement rhetoric against the energy industry. Pundits have declared how oil stocks are the new tobacco stocks without the slightest understanding of complex global energy markets. Unfortunately, no one bothered to provide an equivalent Surgeon General's report this time around.

Making matters worse, the agencies charged with providing reliable timely oil market data have done anything but. As we have discussed in our letters for years, the IEA chronically underestimates global oil demand, mostly from the non-OECD world. Their estimates of supply and demand rarely reconcile with observed inventory behavior, often by 1 m b/d or more. We refer to this discrepancy as the "missing barrels," and we have explained that we instead believe they represent under-estimated emerging market demand. The IEA's February 2022 Oil Market Report proves our analysis was correct.

In their report, the IEA revised non-OECD demand higher by nearly 1 m b/d every year going back to 2018. Beginning in 2010, the IEA has now underestimated global oil demand in 10 of 12 years (leaving aside 2020) by nearly 1 mm b/d each year on average. This is a systematic problem with their methodology and yet few people openly acknowledge the ongoing errors. As recently as 18 months ago, conventional wisdom held that 2019 would mark the all-time peak in global oil demand. Instead, 2022 demand will likely surpass the previous record with no signs of slowing down anytime soon. The IEA now expects global demand will reach nearly 102 m b/d in Q3 of 2022, three months earlier than even we had predicted. Given the IEA's propensity to underestimate demand, the final number could come in even higher. Gasoline and diesel demand are setting new records around the world and even aviation fuel is back to pre-pandemic levels despite travel restrictions still in force (notably in Asia).

Many of our clients want to know about oil demand destruction. They want to know what oil price will impair global economic activity. This is a very difficult question to answer, but both history and theory can point us in the right direction. We have done a lot of work on the history of energy. Throughout most of human history, energy was provided by biomass with an EROEI of 10:1. This relatively low energy efficiency did not leave any surplus energy for growth. Neither GDP nor population grew until commercial coal deposits were developed in the seventeenth century (please see our video here to learn more). If an EROEI of 10:1 resulted in de minimis economic growth, what can we use this 10:1 number to infer about how high oil prices can go today? An EROEI of 10:1 means that 10% of all energy goes to sustain the energy supply. If energy is a good proxy for general economic activity, then an economy should stagnate once 10% of its GDP goes towards producing (and by extension consuming) energy. Evidence backs this up. Many academic studies suggest an economy will fall into recession once energy takes up 10% of total GDP – an empirical result that agrees with our theory.

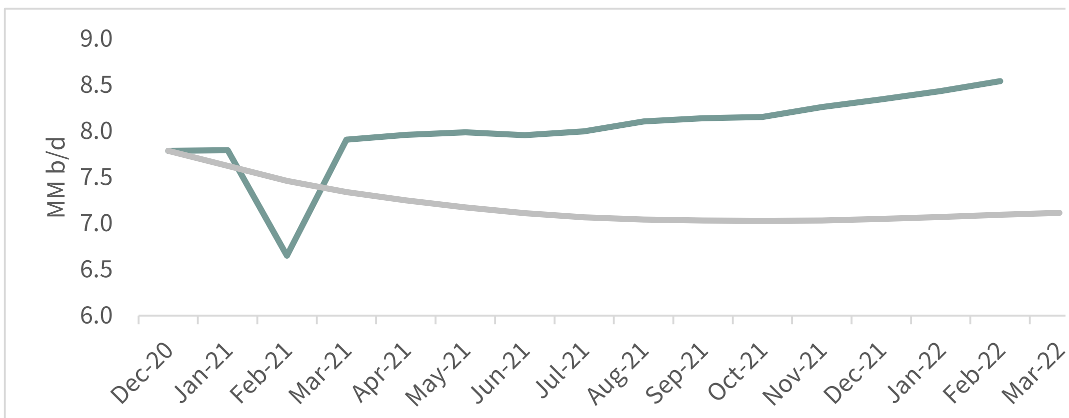
In 2008, energy prices were approximately 10% of GDP right before the global financial crisis. If oil represents about half of all energy consumed, this means an economy will stall when oil represent about 5% of GDP. In 2008, the US consumed 18.8 m b/d. At $120 per barrel that equated to $823 bn or 5.6% of the $14.7 tr US GDP. The economy fell into recession shortly thereafter. In 2012-14, oil consumption never exceeded 3.5% of US GDP and prices stayed between $90 and $100 per barrel with no impact on either demand or economic activity.

Today, oil represents less than 3.3% of US GDP and would have to rise to $140 per barrel before approaching the critical 5% threshold. Why do we focus only on the US? Demand is the most elastic in wealthy countries with high energy intensities and the least elastic in developing countries that need energy to fuel their ongoing development. In 2008, prices spiked as high as $145 per barrel albeit temporarily. In this cycle, we believe oil prices will at some point reach, and potentially significantly exceed the previous $145 per barrel peak before we begin to see evidence of demand destruction.

Misconceptions abound on the supply side as well. Last year, analysts believed energy companies must forgo any further upstream spending lest they risk stranding their assets and impairing their capital. Now, Larry Fink and others admit that perhaps a dearth of capital spending may have negatively impacted global oil supply – an understatement if ever we have heard one. Even OPEC+ spare capacity, long seen as the bearish Sword of Damocles hanging over oil markets, is now being called into question -- something we have argued for a long time. In fact the only bright spot in 2021 oil supply was again the US shales.

We admit we were wrong about shale growth last year. We expected US production to be relatively flat but instead total liquids (including NGLs) grew by 1.4 m b/d between January 1st and December 31st 2021, driven mostly by the shales. In retrospect, we failed to appreciate the huge impact of drilled but uncompleted wells (DUCs). After prices collapsed in 2020 many shale producers postponed completing newly drilled wells to save costs. As prices recovered, they tapped into their inventory of DUCs. Last year, the average energy company completed two wells for every well drilled. Clearly this boosted production but DUC liquidation cannot go on forever. Our models tell us the aggregate impact of accelerated DUC completions boosted production by 1.3 mm b/d in December 2021 and that without the DUCs, supply would have been flat.

FIGURE 8 US Production & DUC Liquidation Impact



Source: EIA, G&R Models...

MOST OF THE DUCS HAVE BEEN DEVELOPED AND ARE NOW IN PRODUCTION. FROM A PEAK OF 9,000 WELLS IN THE AUTUMN OF 2020, DUCS FELL BY HALF AND TODAY STAND AT 4,500. AT THE CURRENT RATES, DUCS WILL BE BACK TO "NORMAL" LEVELS BY MARCH.

Most of the DUCs have been developed and are now in production. From a peak of 9,000 wells in the autumn of 2020, DUCs fell by half and today stand at 4,500. At the current rates, DUCs will be back to "normal" levels by March. Production will falter unless drilling activity picks up sharply from here, and permitting data tells us this will not happen. Remember, public company capital spending is only expected to rise 8% in 2022. Cost inflation is rampant in the oil patch and so current budgets do not leave much room for any increased drilling at all.

Before a company drills a well, it must apply for a permit several months beforehand. A pickup in permitting activity so far has been weak, suggesting an increase in drilling activity is not imminent. The most recent data for December 2021 shows new well permits unchanged from the six-month average. Therefore, drilling will likely not accelerate much from here before DUC inventories normalize in March. We will continue to monitor this closely, but as of now we believe shale growth will begin to stall sometime in Q2.

The IEA expects US liquids production (including NGLs) to grow by 750,000 b/d between January 31st and Q4 of 2022. Instead, our models suggest that at current rig counts and assuming one completion for every well drilled, production will only grow by 200,000 b/d from here. Please note that production did grow last year, and so even if production were flat from January 1st to December 31st 2022, year-on-year growth would still average 1.1 mm b/d because last year production ended above its year-long average level. Nevertheless, we think that incremental growth will be hard to come by going forward unless activity picks up measurably.

Production from the rest of the non-OPEC+ world continues to disappoint, just as we predicted it would. Over the last four months, the IEA has revised its non-OPEC+ ex-US estimates lower by nearly 300,000 b/d for 2022, very much in keeping with our models. Going forward this non-OPEC/non-US block will offer little in the way of new production. According to the IEA data, only Brazil is expected to grow production between January 31st and 4Q22 by more than 100,000 b/d. The only other source of expected growth is global biofuels, which given our concerns around agricultural output we expect will be revised lower.

Given our outlook for demand and non-OPEC+ supply, we continue to believe the call on OPEC+ crude will exceed its pumping capability in Q4. The IEA now makes the distinction between "spare capacity" and "rapidly available" spare capacity – which immediately calls into question the ability of the cartel to produce at the higher level. Our models tell us that only Saudi Arabia and the UAE have any material true spare capacity available. Iraq has 300,000 b/d of potential spare capacity, but it is contingent on improving security conditions. The most generous estimates assume Iran could increase production 1.3 m b/d from here contingent on a nuclear deal, which seems to be moving forward. As we wrote about in our introduction, we believe Russia has little room to grow production from here.

Another problem is depletion in the rest of the OPEC+ world. In January 2022, 10 of the 16 countries subject to production quotas were producing below their allotted limit. In aggregate, these countries missed their target by over 1.0 m b/d. Low prices have had an impact on OPEC+ reserves as well. No one has modeled ongoing OPEC+ disappointments which could further tighten balances.

Assuming Iranian volumes come back, Iraq boosts production and no other countries suffer unexpected outages (all very generous assumptions), we still estimate that OPEC+ spare capacity only amounts to 2.8 m b/d. Based upon our models, all of this capacity will be needed by the end of this year.

As far as we can tell we were among the first investors (along with Mike Rothman at Cornerstone Analytics) to make this call when we wrote about it in 3Q21 While more analysts agree with us today, few of them have thought through the implications. The truth is no one knows what will happen when we run out of spare pumping capacity potentially this year. During the two oil crises of the 1970s, OPEC maintained significant spare capacity. Even when prices ran to $145 in 2008, OPEC's spare pumping capability was substantial. Never in the history of world oil markets have we been in this situation--- we are about to enter unchartered territory.

Ultimately, the oil market deficit will resolve once capital spending is allowed to increase to help offset declines and encourage production growth. Looking over the past decade, the

FIGURE 9 Oil Balances

	IEA	Adj	G&R
Demand	101.6	--	101.6
2H22 Revisions		0.4	0.4
Total	**101.6**	**0.4**	**102.0**
Production			
US	18.4	(0.5)	17.9
Non-OPEC+ Ex US	30.6	(0.6)	30.0
OPEC+ NGLs	8.0	(0.3)	7.7
Total	**57.0**	**(1.4)**	**55.6**
Call on OPEC+ Crude	**44.6**		**46.4**
Current OPEC+	43.6	--	43.6
Spare Capacity	6.4	(3.6)	2.8
Pumping Capability	**50.0**		**46.4**

Source: IEA, G&R Models.

cumulative E&P capital spending shortfall is likely in the hundreds of billions of dollars. Until this investment can be restored, the market deficit will likely remain acute.

FIGURE 10 OPEC+ Spare Capacity

	Jan. 2022	Estimated Total Capacity		Implied Spare Capacity	
	Actual	**IEA**	**G&R**	**IEA**	**G&R**
Algeria	1.0	1.0	1.0	--	--
Angola	1.2	1.2	1.2	--	--
Congo	0.3	0.3	0.3	--	--
EG	0.1	0.1	0.1	--	--
Gabon	0.2	0.2	0.2	--	--
Iraq	4.3	4.8	4.6	0.6	0.3
Kuwait	2.6	2.8	2.7	0.2	0.1
Nigeria	1.4	1.5	1.4	0.2	--
SA	10.1	12.2	10.5	2.1	0.4
UAE	2.9	4.1	3.5	1.2	0.6
Iran	2.5	3.8	3.8	1.3	1.3
Libya	1.0	1.2	1.0	0.2	--
Venezuela	0.7	0.8	0.7	0.1	--
Azerbaijan	0.6	0.6	0.6	--	--
Kazakhstan	1.6	1.7	1.6	0.1	--
Mexico	1.6	1.7	1.6	0.1	--
Oman	0.8	0.9	0.8	0.1	--
Russia	10.0	10.2	10.1	0.2	0.1
Other	0.8	0.9	0.8	0.1	--
Total	**43.6**	**50.0**	**46.4**	**6.4**	**2.8**

Source: IEA, G&R Models.

We have argued for years that negative rhetoric and anemic spending would bring about an energy crisis, and we think that is now upon us.

Europe Realizes Uranium is Green

A new nuclear renaissance might finally be here. Several important developments have taken place in the uranium industry with very positive implications. On January 11th 2022, the European Union's Sustainable Finance Taxonomy confirmed that both nuclear and natural gas would be included as "green" sources of energy. The Sustainable Finance Taxonomy is a critical component of the European Green Deal adopted in 2020. The "Taxonomy" acts as a classification system determining whether a given technology is environmentally sustainable. Once a technology is included in the Taxonomy, investors who have already committed to climate change mitigation are allowed to invest without running afoul of their investment mandates.

The decision was not without controversy. Several countries, notably Germany, vehemently objected to nuclear energy being included in the plan. Germany has spent the past decade decommissioning most of its nuclear power generation capacity following Fukushima. Instead of nuclear energy, Germany advocated for wind and solar as well as natural gas as a bridge fuel. Despite these objections, the commission decided that nuclear power must be a critical component to a decarbonized future. We have long argued that nuclear must be part of any energy future – green or otherwise. No other energy source offers superior energy return on energy investment (EROEI) than nuclear power. Furthermore, no other energy source can dispatch the carbon free baseload power needed to run the modern world.

We first argued that nuclear was the key to a "green" future in 2018. At that time, we could not get anyone to agree with us. Four years later, a widespread energy crisis has led policy makers to act on our argument. The implications will be tremendous.

Over the last two years, over $1 trillion has been invested in ESG-friendly products. This capital is now free to invest in uranium. At the same time, there are only two major producing uranium companies (Cameco and Kazatomprom – both of which we own) with a combined market capitalization of $18 billion. Total global mine supply at today's uranium spot prices of $40 per pound equates to a mere $5 bn. The price of uranium and uranium related equities could surge now that previously restricted capital is able to move into the industry.

No sooner than the Taxonomy was announced, France redoubled its commitment to nuclear energy. On February 10th, President Macron declared the country must "pick up the mantle of France's big nuclear adventure again." As part of his plan, Macron announced they would build six new reactors as well as extend the 40-year lifecycle of existing facilities to more than 50 years, impacting the 56 reactors in operation. France currently generates 70% of its electricity from nuclear power – the highest in the world, and it's no coincidence that France's per capita CO_2 output is half the level of other industrialized countries such as Germany, Japan, South Korea and Taiwan.

CHINA, INDIA, SOUTH KOREA, THE UAE, AND EUROPE NOW ALL VIEW NUCLEAR POWER AS BEING CENTRAL IN REACHING THEIR EMISSION TARGETS GOING FORWARD. DESPITE HAVING INVENTED THE TECHNOLOGY, THE UNITED STATES IS THE ONLY MAJOR REGION STILL TO EMBRACE THE ROLE OF NUCLEAR POWER IN THE "GREEN" FUTURE.

China, India, South Korea, the UAE, and Europe now all view nuclear power as being central in reaching their emission targets going forward. Despite having invented the technology, the United States is the only major region still to embrace the role of nuclear power in the "green" future. Instead, the US continues to shut down nuclear capacity. The second and third units at Indian Point were decommissioned in 2020 and 2021, leaving New York City vulnerable to power disruptions. Diablo Canyon's two 1.1 GW reactors are likely the next to be decommissioned over the next few years, leaving California to increase coal-fired power imports from adjacent states. We hope the United States can bring its stance towards nuclear in line with other countries before many of its best power assets are irreversibly decommissioned.

Turmoil in Kazakhstan threatened the world's largest source of uranium mine supply (Kazatomprom at 40% of global supply) in early 2022. Rising natural gas prices led to riots on January 1st once the government removed consumer price caps. Protesters clashed violently with police and military in the days that followed until a coalition of foreign troops led by Russia entered the country and stopped the protests. The country seems to have stabilized for now with little disruption to uranium production, but this is a situation that must be monitored very closely.

Cameco announced it would move to restart production at its shuttered McArthur River mine in Saskatchewan. The mine, which once produced 15 mm pounds of uranium, was put on care-and-maintenance in 2018 and has remained shut ever since. Many uranium bears viewed the potential restart of McArthur River as an overhang on the uranium market. The worry was that if McArthur River were restarted, uranium could potentially flood the spot market depressing prices. Instead, Cameco announced that it would restart the mine in 2024 to satisfy the newly executed contracts, leaving the spot market unaffected. Investors responded very favorably to the news.

The inclusion of nuclear power in the European taxonomy paves the way for a new generation of European generating capacity. China and India both continue to move forward rapidly with their development plans. US fuel buyers remain extremely uncovered, particularly in 2023 and 2024, and will likely have to return to the term contract market imminently. The McArthur mine restart, announced on the back of new contracted volumes suggests this might already be happening.

Not only is nuclear power the solution to climate change, its exceptional EROEI would help unleash a huge amount of surplus energy and increased prosperity. For investors, the small size of the industry suggests that an influx of capital could have a huge impact on asset values going forward.

Ongoing Shortages for Global Natural Gas

Without US liquefied natural gas (LNG), Europe may well have frozen literally to death this winter. We believe what is happening with global natural gas is a harbinger of things to come for the rest of the energy complex as well.

North American readers could be forgiven for not appreciating how fast international gas markets have turned from surplus to deficit. In May 2020, European 1-month ahead natural gas prices (as measured by the TTF index) reached $1.24 per mcf – an all-time low. By December 2021, prices had spiked to $59.97 per mcf (equivalent to $360 per barrel oil). Prices have pulled back but remain at $25 per mcf (equivalent to $150 per barrel oil) – higher than any other time in the past 20 years. LNG prices into Asia, as measured by the JKM Japan-South Korea Swap Index, bottomed at $2.00 per mcf in 2020, rallied to $49.00 in 2021 and have now settled back to $25 per mcf.

Factories have been forced to shut across the UK, Europe, and Asia after not being able to secure natural gas. Nitrogen based fertilizers rely on natural gas as a key feedstock, and as a result CF closed several facilities in the UK. The agricultural section discusses how the natural gas crisis will impact our food supply.

As the Northern Hemisphere winter draws to a close, there is relief in sight as heating demand wanes. However, there are lingering consequences that will persist. For example, despite using record-high prices to attract imports, Europe was unable to stop inventories from drawing relative to seasonal averages. Based upon the most recent data, European natural gas storage stands at 1.3 tcf – the lowest absolute level for this time of year since 2011. European storage typically ends the winter heating season at 36% capacity by the end of March. Currently, storage is only 35% full, with seven weeks of withdrawal still to come. On average, storage draws by another 14 percentage points between now and the end of the withdrawal period. If withdrawals average even half the normal rate, European storage will end the season way below the 30% capacity – the same level that produced last year's crisis. Unless natural gas injections are dramatically accelerated throughout the spring and summer, Europe risks heading into next winter with dangerously low inventories once again. How will they source the gas?

Europe's natural gas shortage has impacted geopolitics as well. Russian exports to Europe have fallen by half compared with seasonal averages. Currently, Russia sends gas to Europe via Ukraine and Poland. Nord Stream 2 would circumnavigate these countries and deliver gas directly into Germany, allowing Russia to threaten Ukrainian energy security without simultaneously threatening all of Europe. The United States has warned Russia against using Nord Stream 2 as a political bargaining chip and has proposed sanctions on gas flowing through Nord Stream 2. With the pipeline now complete, the next step is for German regulatory authorities to approve the project which is unlikely until at least the second half of the year. In the meantime, Europe must import all its Russian gas via Ukraine with substantial risk for disruption.

THESE DYNAMICS LEFT EUROPEAN LNG BUYERS SCRAMBLING TO BID AWAY GLOBAL CARGOS. MUCH OF THIS DEMAND HAS BEEN MET BY US EXPORTS WHICH HAS BEEN DUBBED "FREEDOM GAS." MIDDLE EASTERN CARGOS MEANT FOR JAPAN WERE RECENTLY DIVERTED TO EUROPE AS WELL WHICH FURTHER TIGHTENS THE ASIAN MARKET. THE CURRENT EUROPEAN TIGHTNESS MAY BE BLAMED ON UNRELIABLE RENEWABLES, COLD WEATHER, OR RUSSIAN POSTURING, BUT ULTIMATELY THE UNDERLYING CAUSE HAS BEEN STRONG ASIAN DEMAND.

These dynamics left European LNG buyers scrambling to bid away global cargos. Much of this demand has been met by US exports which has been dubbed "freedom gas." Middle Eastern cargos meant for Japan were recently diverted to Europe as well which further tightens the Asian market. The current European tightness may be blamed on unreliable renewables, cold weather, or Russian posturing, but ultimately the underlying cause has been strong Asian demand. European utility buyers felt they could source LNG cargos only to realize that incredibly strong Asian demand had drawn away any available excess supply. This trend will only accelerate from here. As countries get richer, they demand not only more energy but also cleaner energy. Natural gas is a much cleaner-burning fuel than coal and many emerging market economies have steadily sought to shift from the former to the latter. This shift will only accelerate going forward. For a more detailed discuss on the reasons behind the strength in LNG demand, please read the essay: "LNG Demand Set to Surge" in our 4Q20 letter.

Natural gas in the US is expensive by recent standards, but cheap compared with the rest of the world. After bottoming in June 2020 at $1.48 per mcf, Henry Hub spiked to $6.31 by January 27th before settling back to $4.00. While these were some of the highest prices in the past decade, they remain 85% below global LNG. The difference is because the United States is bottlenecked in terms of its export capability. Last year, the US exported 10 bcf/d of LNG, effectively utilizing all available liquefaction capability. Once LNG exports are maxed out, North America reverts to an isolated market and gas prices decouple from the rest of the world. Any industry that can take advantage of the arbitrage between US and world prices is currently doing so such as LNG, petrochemicals, and nitrogen-based fertilizer production.

Expansions at Cheniere's Sabine Pass and the start of a new US LNG export terminal, Calcasieu Pass, will push LNG export from 10 bcf/d to nearly 12 bcf/d in 2022 leaving the US as the largest LNG supplier in the world, ahead of Australia and Qatar. This is an incredible milestone, considering that, as recently as the mid-2000s, consensus opinion held that the US would require massive LNG import terminals to meet domestic demand.

All this demand is having an impact on US inventories which now stand 250 bcf below seasonal averages. Although not as dire as Europe, the US remains vulnerable to any bout of cold winter between now and the end of the winter heating season in late March. One interesting observation is that over the past decade, North American autumns have become milder while springs have become colder. If this pattern occurs this year, prices could spike.

On the supply side, the US shales are once again growing. Between January 1st and December 31st, the shales grew by 2.4 bcf/d after having declined by 1 bcf/d over the same period in 2020. While this is certainly an abrupt change, it's a far cry from the 2017 to 2019 period when US gas supply regularly grew by 10 bcf/d or more each year. Last year's growth came mostly from Haynesville shale in east Texas and Louisiana which saw dry production grow from 12.5 bcf/d in December 2020 to 14 bcf/d twelve months later. Our models tell us this growth may be harder to achieve this year. Much of last year's acceleration was caused by drilled but uncompleted wells. Between December 2020 and 2021, operators increased their drilling activity by 28% from 39 to 50 wells per month. Over the same period they increased their completion activity by 150% from 23 wells to 58 wells per month. Since 2014, the industry on average has completed 93% of the wells it has drilled and if that ratio holds again in 2022, production growth will likely slow from 1.5 bcf/d from January 1st to December 31st to only 500,000 mmcf/d.

The other main source of growth was the Permian Basin. As we discussed in our oil section, DUC liquidation had a huge impact in 2021. Whereas the industry normally completes 93% of the wells it drills, 2021 saw this jump to 150% -- clearly unsustainable. Were the Permian operators to revert to its long-term average, dry gas production would likely stop growing entirely. Also, keep in mind LNG export capacity will increase by 2 bcf/d this year and all that supply will likely be needed to meet international demand. Therefore, if the US shales do grow, albeit at a slower rate, domestic inventories will likely fall from here. If we experience a colder than normal later winter and spring in the US, we could see significant upside price pressure.

We are currently undertaking a major overhaul of our neural network models and hope to have new insights regarding US shale production in our next letter.

International natural gas markets will likely be driven by weather as we enter into the shoulder season and we would not be surprised if prices moderated from here. However, mild temperatures do not change the underlying tightness in global gas markets. Demand from emerging markets remains extremely strong (something we have predicted for nearly a decade) while capital investment in new global gas projects remain de minimis.

Europe may not freeze this winter, but the challenges to the global gas markets are not over yet.

From Poor to Rich – A Study of Global Grain Demand

“The Fertilizer Crisis Is Getting Real for Europe Food Prices. Bloomberg, January 21, 2022.

“Fertilizer Frenzy: North American Prices Surged as Energy Cost Spiraled, Leading to Shortages.” Bloomberg, December 9, 2021.

“It’s no secret farmers are faced with a fertilizer crisis.” Agri-Pulse, January 21, 2020.

“Animal Manure Demand Skyrockets” Bloomberg, December 9, 2021.

In past letters we discussed how the global energy crisis, now impacting global natural gas prices, has already severely impacted both the supply and price of global fertilizers. The production of fertilizer is incredibly energy intensive—especially nitrogen--and several companies and countries have cut back production and introduced export restrictions, namely China and Russia.

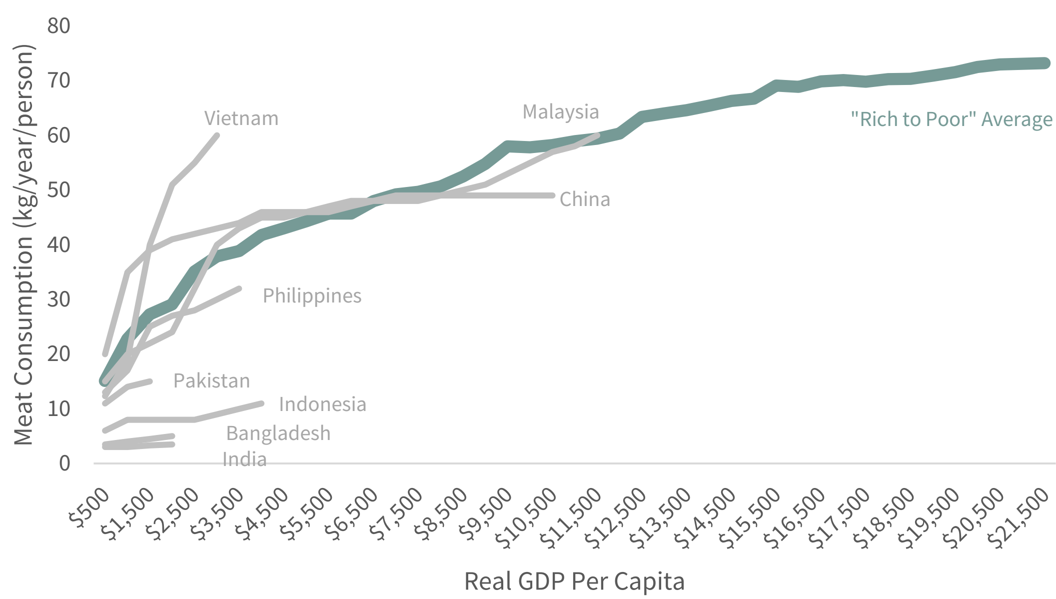
Prices have surged over the last years, and stories proliferate on the difficulty farmers face today in securing fertilizer supply for the upcoming 2022 planting season. As discussed in our last letter, phosphate and potash field applications can be reduced for a number of years before crop yields are impacted—both minerals can remain stored in the soil for years. However, nitrogen is completely different. Nitrogen evaporates out of the soil and has to be re-applied every year, and sometime twice a year -- a practice known as side-dressing. Any reduction in the annual reduction of nitrogen application will have an immediate impact on crop yields. We’ve also heard that farmers are considering reducing their US corn acres planted this spring because of nitrogen’s high price and lack of availability. 2021-2022 corn ending stocks have risen to normal levels as yields surprised to the upside compared to our neural network prediction. However, given the pressure now being put on potential corn supply, first from fertilizer related yield reductions and now from fertilizer related reductions in corn acreage plantings, there is a significant chance that 2022 corn production will fall significantly short of last year’s levels. We will be carefully following how these trends unfold as the 2022 planting season progresses.

We continue to believe that a global agriculture crisis is about to engulf us. Strong grain demand, combined with changing weather patterns, will force grain prices significantly higher as we progress through this decade—a process that has already begun.

Between 1980 and 2000 global grain demand consumption grew by 1.3% per year. Since 2000, grain consumption has ratcheted up by almost 75%--to 2.3% per year. The shifting up of trend-line growth was driven by explosion in the people living in emerging market economies experiencing significant economic growth. As an emerging country’s economy grows, and its per capita wealth increases, grain demand increases as consumers begin to change their dietary preferences. Meat consumption, considered a luxury when a person is poor, replaces rice and other grains when incomes rise. Our models suggest that people go through a massive increase in grain demand as they go from $1,000 to $15,000 in real per capita GDP. After that point, grain demand levels off. For most of the past 150 years, there were approximately 700 mm people in that wealth range at any one time. Today, because of the tremendous growth in the emerging markets over the last 20 years, we calculate this figure stands at almost 4 billion people today.

To demonstrate this relationship in emerging markets between income and changes in the levels of animal protein consumption, we created a composite index of that tracks this change as experienced by the only five emerging market economies in the last 60 years that have successfully transitioned from being poor ($500 per capital GDP) to being rich (as defined as $20,000): Japan, South Korea, Taiwan, Spain, Portugal. (Singapore is also a member of this group, but we are unable to get pre-1980 data histories of animal protein consumption.) At the $500 per capita level, the average meat consumption in these five countries was only 15 kilograms per person. At the $10,000 per capita level, their per capita meat consumption had soared by almost 4 fold –to almost 60 kilograms per person. By the time these countries had hit the wealthy category of $20,000 per capita, their per capita meat consumption had increased again by over 20% -- reaching a level of 73 kilograms per person.

FIGURE 11 Poor to Rich -- A Study of Grain Demand



Source: Helgi Library, World Bank.

Using our "From Poor to Rich" index, we can roughly calculate where animal protein consumption is headed in any emerging market economy. China, for example, has stressed repeatedly that it wishes to avoid getting caught in the "middle Income trap." Their goal is to become a rich country, meaning they wish to achieve a $20,000 level of per capital GDP. If the intensity of historical meat consumption follows our composite index, and if China is successful in its quest to become "rich," then China's meat consumption should eventually reach 73 kg per person, up from 48 kg today. Assuming that it takes 3 kg of grain to produce 1 kg of meat protein, we calculate that China will need to consume an extra 100 tonnes of grain annually in order to produce this extra 25 kg of meat per person. Putting these amounts in context: this 100 mm tonnes represents 35% of the size of the United

States corn crop and almost 15 % the size of China's total estimated 2021 grain production-- 680 tonnes. If China's per-capita real GDP reaches $20,000 in 15 years (approximately 5% annual growth), we calculate that China's increase in grain consumption alone will add an additional 0.4% to the global consumption growth rate. In previous letters, we have talked about continued strength in Chinese grain demand, much of it supported through grain imports and how this strong demand will continue as we progress though this decade. You can easily see from this chart the reasons behind the strength in past demand, and why this strong demand will continue for years to come.

But carefully note that China is only one of eight Asian emerging market countries experiencing rapid increases in their animal protein consumption. The other seven countries on this chart represent 2.4 bn people, or 30% of world population. They are all roughly following this same grain consumption trajectory. Some countries have overshot their predicted grain consumption (for example, Vietnam) and some are undershooting, such as Indonesia, India, Pakistan, and Bangladesh but, it seems highly likely we should expect significant increases in grain consumption in all these countries in the next 10 years as their per capita wealth increases.

India is of particular interest. 80% of Indians are estimated today to be protein deficient and, contrary to general opinion, there is no direct restriction in Hindu scripture that prevents the eating of animal protein, other than discouragements to consume cow meat. Could India experience a huge catch-up in animal protein consumption as its per capita wealth rises rapidly this decade? India's animal protein consumption is something we are watching closely, especially given India's massive 1.3 bn population and its rapid economic growth.

Also please note there is nothing to hinder (for example restrictions on pork consumption) large potential increases in animal protein consumption coming from the three big Muslim countries listed on the chart: Pakistan, Bangladesh, and Indonesia . Animal protein consumption levels for all are extremely depressed relative to their income levels, and we believe they could play huge catch-up this decade as incomes rise. Supporting this viewpoint, you can see that Malaysia, a predominantly Muslim country, has followed almost exactly the animal protein consumption trajectory predicted by our composite index with a per capita GDP of $11,000 and consumption of 58 kg of animal protein. If Malaysia's animal consumption history is any guide, the odds are pretty high that we should see large increases of animal protein consumption levels coming from all these three countries as their economies rapidly grow. Given their combined population of 500 mm, it's something we will be watching closely.

Copper Inventories Draw

Favorable fundamental trends continued into the end of 2021. After surging almost 15% in 2000, China's copper demand has fallen about 7% for the nine months of 2021, according to World Bureau of Metal Statistics (WBMS), however, most of this decline has been offset by growth in global copper demand outside of China. On the supply side, global copper supply has rebounded somewhat from 2020 COVID impacted declines, but copper mine supply continues to stagnate. Copper mine production today is only up slightly from where it was in 2016. Over the last six years, copper mine supply has shown minimal growth. Resilient demand and sluggish supply growth is now being reflected in global copper inventories. Combined warehouse inventories of the Shanghai, London Metals exchange, and the COMEX peaked back in the summer of 2018 at almost 900,000 tonnes and declined steadily since. Today they stand at only 190,000 tonnes, a fall of almost 80%.

Back in the summer of 2005 combined copper inventories of all three exchanges covered daily global consumption by only 2 days-a dangerously tight situation, and it's was no coincidence that copper prices surged 2.5 times in the next six months. Today, copper inventories cover daily consumption by only 3 days, and we are again approaching the dangerously low levels seen back in 2005.

Confirming the tightness in today's copper market are the future market's backwardation, defined as when commodity markets are tight and inventories are low, future prices will trade at big discounts to spot prices. Conversely, when inventories are sufficient, future commodity prices will trade higher than the spot prices-- a condition known as "contango." In today's COMEX copper future market, the July 2024 contract trades at $4.26 per lb. versus today's copper spot price of $4.40—a discount of 14 cents to the spot market—which amply displays the tightness that crept into today's physical copper market.

Copper prices have traded in a tight band over the last 12 months oscillating between $4.00 and $4.80 per pound. We believe we are setting up for the next big price spike. Investors should maintain significant exposure to copper related equities.

How Long Will the Gold Correction Last?

Our readers know that we significantly reduced our gold exposure after silver staged a furious five-month catch up rally that started in April 2020. Historically, when silver prices lag gold prices for an extended period of time and then stage a huge catch-up rally, this has always produced either a significant period of precious metals price correction or an outright bear market. For those interested in our thoughts, please refer back to the essay "Will Gold Take a Breather?" that appeared in our 3Q 2020 letter. Since we wrote that, the gold price has been behaving much along the lines we predicted.

We are also huge believers that this gold bull market which started back at the end of 2015 when gold bottomed at $1,050 per ounce, is far from over. We have great confidence that gold will greatly surpass $10,000 before this decade is over---a price target that we have discussed often.

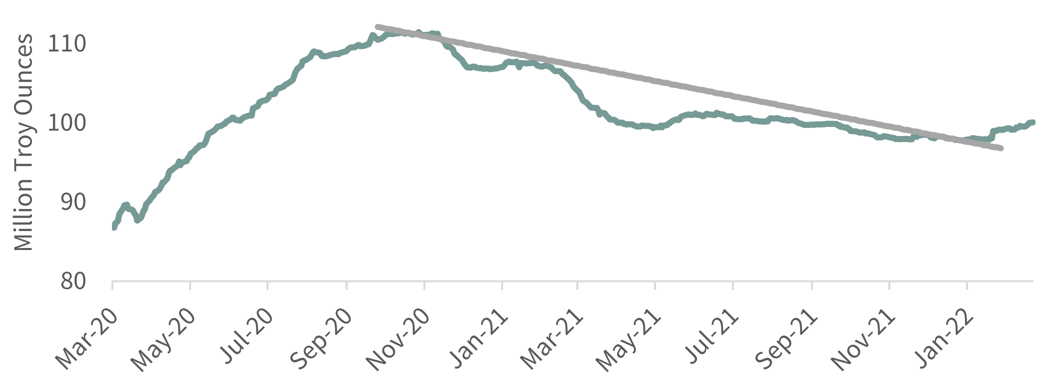
So the question facing investors who today are now sitting on the sidelines is how long will the corrective phase last and when should I significantly increase my investment exposure to precious metals and related equites? It's an important question. Not only have precious metals investments sported lackluster returns over the last 18 months, but for natural resource investors, the opportunity cost of being exposed to precious metals has been extremely large--other areas in the commodity sphere have produced outsized returns over that time period. Even in the short term that opportunity cost has been high. For example, just since the beginning of 2022, the GDX, the popular gold stock ETF, is approximately flat whereas the XOP ETF (which mirrors the return of the S&P index of exploration and production stocks) has surged almost 20%. At some point, the precious metals sector is going to become undervalued relative to other commodities, (as well as to inflation) and the switch into precious metals investment will be handsomely rewarded. But the question still remains when should investors make the switch out things like oil, gas, copper, and agriculture into precious metals?

If history is any guide, we still have further to go in the corrective phase, but extremely strong positive trends are beginning to emerge and we recommend that investors continue to slowly accumulate physical gold and silver, as well a precious metals related equities which today trade at extremely cheap levels. We can't pinpoint when gold's next bull market leg will start, but we do want to have exposure when it does. We still believe that this gold bull market will be driven by western investors who will hold the various physical gold and silver ETFs as an easy, low-cost way to gain exposure.

The influence of the western investor on the gold price can be easily seen. Between the August 2018 (the beginning of the latest big move in gold) and August of 2020 (when the gold price topped-out) , the gold holdings of the 16 physical gold holding ETF's we followed showed at 70% gain , in contrast the gold price advance 75%. Since August of 2020, the gold holdings of these ETF have fallen by almost 12%, almost exactly in the line with the 13% fall in the gold prices.

As clearly show on the chart below, the shedding of physical has slowed significantly and may have now stopped. You can also see that the downtrend in gold shedding the by 16 physical gold ETF's we follow has been broken by the recent surge in new purchases. The gold holdings of these ETF's bottom at a little of 2,900 tonnes in the last week in December of last year, and since then gold holdings have surged 60 tonnes in the last four weeks. The breaking of the downtrend in gold shedding, which has been in place since November 2020, lend significant credence that a new gold accumulation phase among western investments has begun.

FIGURE 12 Total Known ETF Gold Holdings



Source: Bloomberg.

Central banks have also started buying gold once again. You will likely recall that central banks spent most of the 1990s and 2000s selling most of their gold right at the bottom. In 2008, France, Sweden, and Switzerland bought gold and since then central banks have been net buyers every year. Central banks are an important player both because of their size and because they are price inelastic. In 2018 and 2019 central banks were huge gold buyers adding over 600 tonnes in each year. Things changed in 2020, when Russia stopped buying and

Turkey announced it would sell gold. Central banks in aggregate slowed their buying by 55% in 2020 to only 275 tonnes – the lowest rate in 10 years. Although seldom discussed, we believe this explains why gold prices have been lackluster. After a very slow start to 2021, central bank gold purchases rebounded significantly in the second half. Central banks purchased 340 tonnes driven by Thailand, India, Hungary, Brazil, and Singapore. The Philippines was the only notable seller.

These positive demand trends tell us that a sharp pullback from here is unlikely. However, we still have one big negative element in place keeping us from adding more to our exposure.

As you know, we are big believers that inflation is going to become a huge problem this decade. Now that inflation is here, we believe the Fed is going to be forced to raise rates, perhaps significantly, in the next several months. How will gold react to the raising of rates? If history is any guide, we could see significant gold price weakness. We've talked of how the huge 1970s gold bull market was significantly interrupted by the Fed's big move in raising interest rates in 1973 and 1974 which forced gold to pull back a huge 45% from its 1974 peak. Will gold's reaction to raising interest rates be as severe this time?

We also continue to monitor the positioning of gold and silver traders in the COMEX future contracts. For those unfamiliar with futures trading, most bear market bottoms are made when the commercials (i.e. commercial users of gold or "the smart money") are net long in their trading positions and the speculators (i.e. the traders who are "trend followers") are correspondingly net short. Since the bottom of the great bear gold market in the early 2000s, there has been only one instance where both commercials were net long and speculators were simultaneously net short in both the gold and silver futures markets: August 2018. Gold and silver prices had been correcting in price since the summer of 2016. Both metals bottomed in August 2018 and then proceeded to advance by over 75% and 100% over the next two years. Gold and silver equities performed even better. Gold and silver equities (as measured by the GDX gold stock EFT and the SIL silver equity ETF) surged by 150% and 130%, respectively.

In retrospect, we know the positive positioning of commercials and the negative positioning of speculators signaled to investors that a great buying opportunity had appeared in both metals. Since then the positioning of traders in both gold and silver markets has stubbornly refused to give the same buy signal.

If history is any guide, we should see significant reversals in the commercial and speculator trading positions before this corrective phase ends. Our hunch is that commercials will go long and speculators short as the Fed's raising of interest rates puts downward pressure on both gold and silver markets which will provide us with a great buying opportunity.

We predict that we are getting closer to the end of the corrective phase of this gold bull market. However, we worry about a negative price reaction to rising short term interest rates. Just in the last two days, gold has fallen by almost $60 per ounce in response to the Fed's announcement that they will beginning raising the Fed's Funds rate in March.

Even so, we have begun to slowly raise our gold exposure in the funds we manage. Our strategy is to use the upcoming weakness in the precious metals complex, possibly brought on by rising interest rates, as an opportunity to further increase our gold exposure.