Goehring & Rozencwajg
Natural Resource Market Commentary

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TRIPLE DIGIT OIL PRICES: ARE YOU READY?

Since we first outlined our thesis one year ago, oil inventories have drawn by as much as 650,000 b/d relative to normal – a record rate. The market deficit continues to get worse, and 2018 should see inventories draw further. With the market in deficit, demand surging higher and the rest of the non-OPEC world feeling the impact of meager conventional discoveries, the burden of balancing the market falls to the US shales. However, signs are emerging that the US shales are exhibiting the first signs of field exhaustion and will not be able to make up the shortfall. Inventories should continue to fall, putting upward pressure on oil prices. Our thesis – $100 oil sometime in 2018 – is looking more and more possible.

"All-time Low For Discovered Resources in 2017: Around 7 Billion Barrels of Oil Equivalent Was Discovered" Rystad Energy, December 21, 2017.

"All That Shale Oil May Not Be Enough as Big Discoveries Drop" Bloomberg News. December 26, 2017

"EOG's well productivity has declined by 40% (in the Bakken) since 2013 -- Pretty Steady Decline every year" Capital One Securities Report, December 19, 2017

In our Q3 2016 letter, we brought up the subject of "Peak Oil" and how we believed the debate surrounding this controversial subject was ready to be revived. We related, "An improper understanding of the productivity of global oil shales, combined with the collapse of conventional oil reserve additions (a subject that no one is covering), will result in 'Peak Oil' re-emerging as a hotly debated topic among investors and analysts over the next several years." Since we wrote this over a year ago, a surge of new data has emerged supporting our viewpoint--one, we should point out, shared by few others. As our readers know, we pride ourselves on our research. Through our research process, we are often able to identify and quantify trends long before

"OIL MARKETS ARE IN THE PROCESS OF UNDERGOING A SIGNIFICANT, LONG-TERM TREND TOWARDS STRUCTURAL TIGHTNESS."

they are recognized by either the wider analytic community or the financial press. In the case of global oil markets, we have undertaken multiple research projects over the last two years that give us great confidence that the oil markets are in the process of undergoing a significant, long-term trend towards structural tightness. This tightening, which we have extensively discussed, started sixteen months ago and, while it continues to gain momentum, investors remain skeptical and unconvinced. Relying on consensus data (which we believe is incorrect), investors in 2017 continued to be gripped by rampant bearishness — a position completely divorced from the underlying fundamentals. This pessimism, combined with strong underlying tightening trends that are becoming harder and harder to reverse, present investors with a phenomenal buying opportunity.

We put forward our controversial viewpoint in January 2017, being so bold as to call for triple digit oil prices at some point in 2018. Since then, global oil demand has surged far beyond expectations, global oil and product inventories have drawn at the fastest rate ever experienced and the US shales (the favorite argument put forward by oil bears) have begun to disappoint. Despite all of these bullish developments, oil prices today are only 10% higher than when we first wrote last January. As we will carefully outline for you in this letter, our research has made us more convinced than ever that oil has entered a huge bull market, and that oil-related investments represent the investment of lifetime.

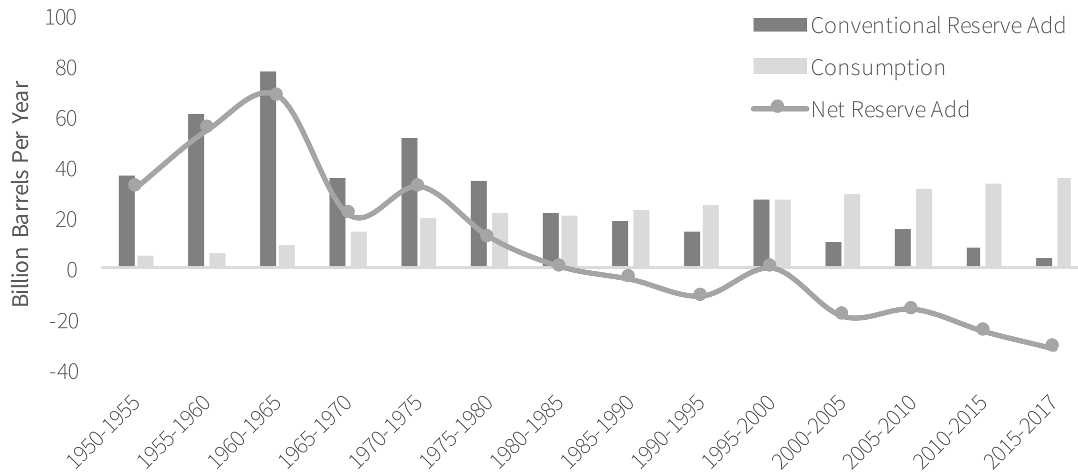
What makes us so bullish, especially when everyone else is so bearish?

Often in severe bear markets, obvious bullish data points sit right in front of us and yet no one seems to notice. For example, in a report put out late last year, Rystad Energy (an international oil and gas consulting firm) stated that global conventional oil and gas discoveries reached an all-time low in 2017. We estimate that the global oil and gas industry only found four billion barrels of new conventional oil last year that capped a dismal 20-year stretch for conventional oil discoveries. Since the start of the shale oil revolution in 2007, discoveries of conventional oil (not including shale) have totaled approximately 110 bn barrels while consumption has totaled 360 bn barrels. Thus between 2007 and today, we have consumed an incredible 250 bn more barrels than we have replaced through conventional discoveries -- and this shortfall is accelerating. As you can see on the chart above, over the last six years, conventional discoveries continue to collapse and the deficit between discoveries and consumption continues to grow. According to our calculations, since 2012, we have consumed almost 210 bn barrels of oil, while conventional discoveries have only totaled 40 bn barrels. Over the last six years alone we have consumed 170 bn more barrels than we have discovered through conventional oil discoveries. While the current trend is clearly unsustainable, oil bears remain unpersuaded. They argue that huge discoveries of unconventional oil (i.e. US shales) have made the collapse of conventional discoveries all but irrelevant. Oil shale resources will total in the billions of barrels, say the bears. Discoveries of new conventional oil reserves are therefore no longer necessary in a world where oil shale production is expected to continue its relentless surge.

As readers know, we emphatically disagree with this line of reasoning. As we wrote extensively in our Q3 2016 letter, we have assessed all of the global oil shale basins based on their geological prospectivity (the Middle East is missing from our study due to a lack of published data). Based on our analysis, we concluded that except for three shale basins (the LaLuna shale in Columbia,

CONVENTIONAL REVERSE ADD VS. CONSUMPTION VS. NET RESERVE ADD

CHART 1 Conventional Reserves vs. Consumption



Source: Wood Mackenzie, Goehring & Rozencwajg Models

the Vacua Murte shale in Argentina, and the Bashenov shale in Russia), the shale oil revolution (pioneered here in North America) will not be exportable to the rest of the world.

Also, with the production history now available, we have attempted to estimate how much shale oil reserves will be recovered from the five largest US shale plays. In our last letter, we used a reserve estimating technique called "Hubbert Linearziation" to estimate the total recoverable reserves from the most important US shale plays. We determined that consensus opinion had significantly overestimated the ultimate recovery of oil from these fields. For example, our analysis indicates that both the Bakken and Eagle Ford shale play will recover somewhere between three and four billion barrels of oil each. The Niobrara, (which we did not have time to discuss last quarter) should recover approximately 1.5 billion barrels of reserves. Although very early in its production history, we believe the Permian basin (both the Midland and Delaware sides) will recover 20 bn barrels. Given its limited production history, we have not yet attempted to calculate a reserve figure for the emerging SCOOP-STACK in Oklahoma play; however given its aerial extent, we can make a very rough preliminary estimate that three billion barrels will ultimately be recovered from the play (and we think this very optimistic). Adding up the total recoverable reserves from these five plays, we believe that approximately 30-35 billion barrels will be recovered from the US shales. If we add these reserves to the conventional discoveries discussed above, the world has still consumed 215-220 bn barrels more than it has discovered over the last ten years.

What would happen if our models end up being far too conservative and shale-oil drilling productivity skyrockets from here? Data is emerging that indicates just the opposite might be happening—a topic we will discuss in the oil section of this letter. However, for argument's sake, if we assume that our figures are off by order of magnitude and that the shale plays are ultimately able to recover 60 to 70 billion barrels (an incredibly optimistic figure), then consumption over the last ten years still exceeds total discoveries (shale and conventional) by over 180 bn barrels.

While 70 billion barrels of recoverable shale oil reserves is an extremely large figure, it represents less than 30% of the 250 billion barrel deficit between conventional oil discoveries and global consumption over the last 10 years. Although the development of the oil shales have been a technological marvel and have provided the US with a surge of production, they represent just a drop in the bucket once you take into account the collapse of conventional oil discoveries and the surge in global oil demand.

The concept of collapsing conventional discoveries over the last 10 years is something that analysts neither mention or put in the proper analytic perspective. Given our belief that the Bakken, Eagle Ford, and Niobrara shale plays have now peaked and are in the early stages of decline, we believe that the massive gap between reserve additions and global oil consumption will quickly come to the fore.

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Investors have erroneously attributed an almost limitless amount of reserves and production capability to the shales. However, while investors have convinced themselves that the shales will grow ad infinium from here, more and more evidence has emerged suggesting drilling productivity in the shales is peaking and may very well start to decline — especially in the Bakken and Eagle Ford. The Permian and the emerging Scoop/STACK play will continue to grow strongly over the next several years, however with two of the major shale plays now in decline, it will be very difficult to replicate the back-to-back 1.5 mm b/d annual production growth experienced in the US in 2013 and 2014---a time when the Bakken, Eagle Ford, Niobrara, and Permian Basin were all simultaneously ramping up production.

As we will discuss in the oil section of this letter, our modeling points to something few investors understand regarding the 2018 oil market balances: surging demand combined with the slowdown in shale production growth and the meager growth of oil supply outside of North America means that even if OPEC were to restore all of it November 2016 production cuts (1.2 mm b/d), the 2018 oil market will remain in deficit. It's something that few investors appreciate.

Back in June 2016, we wrote an essay discussing the impact of the electric car and renewables on the global copper markets. We concluded that analysts were completely underestimating new sources of demand at the same time as copper mines supply was set to disappoint. When we wrote, copper was priced a little over $2.00 per pound and investors had reached a point of almost rabid bearishness. We passed along our copper essay to a metals analysts for whom we have great respect and one of the few who (as opposed to his analytic competition) took a very bullish stance towards copper markets. He passed back the following comment: "This is a fascinating read gentlemen. Few, if any are discussing the changes to the market from renewables. I rarely ever get questions about it."

Copper prices have advanced by 60% since we wrote that essay and today you read nothing but stories discussing the impact electric vehicles will have on the global metal's markets. These articles touch on the coming shortcomings of mine supply and how a "structural gap" has now emerged between copper supply and demand. We bring this up as it provides an excellent recent example of how perceptions of underlying trends (often ignored at the start) can quickly change and how investor psychology can change from wildly bearish to bullish in a very short time. For investors who took the time to conduct thoughtful copper market research, nothing has changed in global copper fundamentals over the last eighteen months. What has changed is the investor psychology, having swung quickly from wildly bearish to bullish as underlying fundamental trends became too obvious and pronounced to ignore.

As we speak, we believe this same phenomenon is happening to the global oil markets. Bullish demand and supply trends (subjects we have extensively researched and outline for you in these letters) are becoming more pronounced, and as a result harder to ignore. The bearish psychology is about to break. We remain firmly convinced that oil-related investments will offer phenomenal investment returns. It's the buying opportunity of a lifetime.

Market Commentary

Natural resource markets showed considerable strength in the 4th Q. Of particular note was the surprising advance in oil prices. West Texas intermediate prices advanced at a strong 17% and Brent prices advanced almost 16%. In last quarter's letter, we wrote about the relationship of oil prices to relative inventory levels and pointed out that further inventory drawdowns would push oil prices significantly higher. Global oil inventories continued their plunge in the 4th Q and prices responded accordingly. Despite all the bearish commentary throughout 2017 (shale oil growth, OPEC cheating, slowing global demand, electric cars), WTI and Brent advanced 12% and 18% respectively for all of 2017, returns that have confounded oil bears. Bearish sentiment did express itself however in the underlying energy names. For example the Standard&Poor's Oil and Gas company index (XOP) rose only 9.3% during the quarter, and the Philadelphia Oil Service index (OSX) rose only 5%. Both lagged the sharp 4th Q rise in oil prices. On a year-to-date basis, the lag in performance was even more pronounced. The XOP fell 9.5% and the OSX fell almost 19%. In last year's 1st Q letter, we outlined our case for triple-digit oil prices sometime in the first half of 2018. In the oil section of this letter, we discuss what we believe will be the most important demand and supply trends in the 2018 oil markets. Our research continues to tell us that triple-digit oil prices are a high-probability event as 2018 progresses. Because of their underperformance last year, we believe oil-related investments have presented investors with a tremendous buying opportunity.

Base metals continued to act strongly in the 4th Q. Nickel, the metal "du jour" in the race of what commodities will be most impacted by future electric car production, rose a strong 22% during the quarter. Copper, a metal that we believe will be the true winner in the race to build electric cars, rose 12%. Aluminum, which continues to benefit from Chinese announcements of smelter closings, rose a little over 8% and zinc rose 6%. Reflecting a year where global growth came in surprisingly strong, all base metals showed significant strength in 2017. Aluminum rose 34%, copper 32%, zinc rose 29% and nickel rose 27% per annum. We still believe that copper, based upon both supply and demand trends, has the best fundamentals among the base metals and it continues to be our preferred metal investment. For the year copper stocks significantly beat the market. The COPX, a global copper stocks ETF, advanced almost 40%. Also, we have now turned bullish on another metal—uranium. The uranium market has undergone a devastating bear market over the last 10 years. Everything that could go wrong did go wrong, including the Fukushima "nuclear disaster." With over half of the uranium mining industry now operating at cash operating losses, and with both supply and demand trends having turned positive, we believe the metal has bottomed and a new bull market is about to unfold. Please read the following section on uranium where we discuss the emerging supply and demand issues.

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In precious metals, prices rose between 2 to 3% for most of the metals. The standout was palladium, which rose 13% during the fourth quarter. Continued strong gasoline auto demand in China (palladium is the PGM metal of choice for gasoline engines, while platinum is used with diesel) pushed palladium prices higher. During the quarter, gold stocks, as measured by the NYSE Gold Bugs Index, matched the return of gold and rose a little over 2%. For the year, palladium was the standout precious metal, rising over 55% for the year. Gold rose 13%, silver rose 7%, and platinum rose 3%. For all of 2017, gold stocks matched the advance of gold, advancing by 13%. As we outlined in our 3rd Q 2017 letter, we believe we have entered into a huge bull market in commodities and their related equity investments—a bull market that will rival the bull market we experienced in the 1970s, and in the 2000's.. In both those markets, gold (and all precious metals) were huge participants, and we believe that gold will be a leader in this bull market as well. However, we believe there will be a better entry point for us to significantly increase our exposure to gold and related precious metal investments in this new bull market. We favor oil and oil-related investments today, but if the 1999 to 2011 commodity bull market is any guide, we believe investors will be presented with multiple spectacular buying opportunities in precious metals. For gold investors, please read the "Gold Market" section of this letter carefully. We believe our analysis provides an excellent road map on how a commodity investor should navigate the precious metal market in the coming decade.

"AFTER YEARS OF STAGNANT DEMAND, GLOBAL POTASH CONSUMPTION HAS RISEN STRONGLY IN THE LAST TWO YEARS AND SUPPLY-DEMAND FUNDAMENTALS HAVE IMPROVED DRAMATICALLY. THE STRUCTURAL SURPLUS IN GLOBAL POTASH MARKETS IS NOW RECEDING."

Agriculture prices drifted lower in the 4th Q. The near-record North American harvest of 2017, combined with the great global harvests in 2016 and 2015, continue to cast a bearish shadow over global grain markets. Global grain inventories remain at near record highs, but global grain demand continues to set all-time record highs as well. We have some investments in global agricultural markets, but remain for the most part on the sidelines. However, we are watching certain markets with great interest. For example, after years of stagnant demand, global potash consumption has risen strongly in the last two years and supply-demand fundamentals have improved dramatically. The structural surplus in global potash markets is now receding. Any improvements in global grain markets in 2018 could push these stocks significantly higher. Investor have little exposure and the fundamentals in global fertilizer markets could turn wildly positive if grain prices were to advance. We are watching events closely, and look to increase our exposure, given any changes in underlying grain market fundamentals.

Global Oil Markets

Global oil prices were strong during the 4th Q. The persistent and substantial inventory draws (a subject we have discussed) finally began to impact prices. WTI prices advanced by 16.9% during the 4th Q, breaking through $60 per barrel for the first time since 2015. Brent prices were also strong, advancing by 16.2% to end the year at $66.87, nearly surpassing their 2015 highs. For the year as a whole, WTI prices advanced by 12.5% while Brent prices advanced by nearly 18%. Oil prices were weak during the first half of 2017, finally bottoming at the end of June. Since the lows made on June 21, WTI has advanced by 42% while Brent has advanced by nearly 50%. As we write, strength in the global crude market has continued into 2018, with WTI and Brent has advanced by another 6% and 4.5%, respectively.

Despite the strong performance of crude oil, energy-related securities lagged the price of crude, reflecting the continued (and in our opinion misplaced) bearishness of most energy equity investors. During the 4th Q, energy stocks (as measured by the S&P 500 Energy Index), advanced by only 6.2% - far short of the 16% gain in the oil price. Investors continue to worry that risks from both demand and supply will drive oil prices lower. On the demand side, the perceived threat of electric vehicles and potential slowdowns in China loom large in investor's minds. On the supply side, investors continue to believe an endless shale supply will shift the crude market into surplus – a view we have long disagreed with.

We believe energy-related securities today represent great value. Fundamentals have shifted significantly in underlying markets and investors have yet to taken action. Even though crude prices have advanced by nearly 150% since hitting their cycle bottom February 2016, the energy weighting of the S&P 500 has actually declined from ~6.5% two-years ago to 6.1%, and today its weighting remains some 40% below the long-term average level since 2000.

"TO SAY OUR CALL WAS CONTRARIAN WOULD BE AN UNDERSTATEMENT: IN JANUARY 2017 WE COULD HARDLY FIND A SINGLE PERSON WHO AGREED WITH US."

Twelve months ago, we explained how the global oil market was shifting from surplus to substantial deficit for the first time since 2013. Based upon our modelling of supply and demand, we explained how the OPEC cuts announced in November 2016 would wind up severely over-tightening global oil markets in 2017 and, as a result, the large overhang in OECD oil inventories would be largely eliminated as 2017 progressed. Our models also suggested that IEA 2017 global oil demand estimates would need significant upward revision. We also argued that production growth from the US shales would not be enough to overcome a dearth of new projects from the rest of the non-OPEC world and OECD inventories would draw by ~600,000 b/d as 2017 progressed. To say our call was contrarian would be an understatement: in January 2017 we could hardly find a single person who agreed with us.

As our long-time readers know we like to build road-maps for our research to follow. We set out mile-markers that we must pass to show we are travelling in the right direction. In the case of our bullish oil call, we monitored inventory behavior here in the US (data released by the EIA) and the OECD (data released by the IEA and a good proxy for global inventories) for signs that we were correct. After a rocky start in January and February of last year (please see our 2Q2017 for a detailed explanation), inventories began drawing substantially, and these draws continue today. From the end of February until the end of October (the most recent data available), total OECD crude and product inventories have drawn by nearly 150 mm bbl compared with a 10-year average build of nearly 60 mm bbl for that period. This suggests that the global crude oil market was undersupplied by over 800,000 b/d during that time – even more than our models had suggested. Even with the anomalous builds in January and February, total OECD crude and product inventories declined by nearly 550,000 b/d compared with seasonal averages.

After OPEC abandoned its production quotas in late 2014, the majority of excess global supply found its way to US storage facilities--an outcome not surprising given the huge storage and transportation infrastructure here in the US. As a result, core US crude and product inventories swelled from 780 mm bbl at the end of 2014 to 961 m bbl by the end of 2016. The 180 mm bbl- increase in US inventories represented 60% of the total OECD inventory build over that period. As expected, the bulk of the inventory draws in 2017 came from US storage facilities as well. For 2017 as a whole, US core petroleum inventories declined by 115 mm bbl compared with the long-term average, suggesting the US market was undersupplied by 325,000 b/d for the full-year (375,000 b/d undersupplied if US sales from its strategic reserve were excluded). To put the magnitude of the 2017 US inventory draws in perspective, consider how inventories drew compared with the 2007 period, a year in which oil prices rose by almost 100%. Recall that last year we compared OPEC's 2016 production cut with their decision to cut production back in 2006. At the end of 2006, OPEC (again working off of faulty IEA data), decided to cut production by 1.2 m b/d based upon concerns that non-OPEC production would surge by almost 2.5 mm b/d in 2007. We argued then that these non-OPEC supply growth numbers were unrealistic and that OPEC's decision to cut production would overly tighten global oil markets. In January 2017, we explained how OPEC was repeating its mistake by cutting production into a market already in deficit. This time the magnitude of inventory declines would be even greater. In 2007, US core petroleum inventories drew by 160,000 b/d relative to long-term averages suggesting that 2017's draw of 325,000 b/d were nearly double what was experienced in 2007 – exactly as our models had predicted.

With the benefit of hindsight, what did our models get right and what did we miss? The IEA did indeed revise their estimates for 2017 global oil demand higher over the course of the year. Since the start of last year, cumulative revisions to 2017 global demand averaged nearly 250,000 b/d, including an incredibly large 950,000 b/d revision to 2Q demand. Since the IEA first put out their original estimate for 2017 in June of 2016, their demand estimates have been raised by 400,000 b/d. While these revisions are somewhat less than we had expected, our models suggest that future revisions to 2017 demand are forthcoming. Non-OPEC production (adjusted for Indonesia's move out of and Equatorial Guinea's move into OPEC) was revised higher by 300,000 b/d over the course of the year and was slightly above our estimates as well. This was 100% explained by the US shales – a trend we do not believe to be sustainable and a topic we will discuss later in this letter. Non-OPEC production outside of the US was actually revised down by 170,000 b/d over the course of the year. Better-than-expected compliance from OPEC member countries, whose production now stands 1.1 m b/d below the peak reached in November 2016 also contributed to tightening global oil markets. On balance, we were correct in predicting that strong global demand growth combined with the reduction in OPEC production would far overwhelm any possible increase in US shale output given the dearth of non-OPEC activity outside the US. Just as we predicted, both US and OECD inventory levels have now worked off huge amounts of the overhang accumulated since OPEC's decision to abandon production quotas in 2014. US core petroleum inventories today stand at 70 m bbl above normal while OECD inventories stand at 200 mm bbl above normal (through October), 70% and 50% below their peaks, respectively, and the lowest levels since 2015.

The same models that predicted 2017's inventory behavior tell us now these trends will continue into 2018. In our Q3 letter, we included a chart that showed how oil prices historically move sharply higher once inventory levels get to within 20 mm bbl of historical average levels. We continue to believe that based on current trends, inventories should reach these levels sometime in the Q1 of 2018. Today's oil's price strength is the first sign the market has now reached levels where further declines in inventories will have large corresponding upward moves in price.

To better understand the global oil balances for 2018, let us first start with 2017's global oil market deficit of 650,000 b/d. In addition to the starting deficit, the IEA is projecting that global demand will grow by 1.3 m b/d in 2018 implying that global oil supply must grow by a minimum of 2 m b/d to keep inventories from drawing even further. And, as in past years, we think this demand figure will have to revised up significantly. As we have discussed at length in past letters, the IEA has chronically underestimated global oil demand and has revised up its figures in eight of the last nine years by 1 mm b/d each year on average. Our models tell us that 2018 will be no different. The most important data point to watch will be what we call the "missing barrels," that is oil that is produced but is neither consumed nor accounted for in IEA's storage balances. We have long argued that this oil is not "missing" but rather represents chronic demand underestimation from the IEA's models for non-OECD demand. After going to zero in Q1 and 2, the "miscellaneous to

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balance" barrels have again came back hugely in Q3 of 2017, averaging an incredibly large 800,000 b/d. While oil in transit might explain some of this figure, we believe that underestimation of global oil demand is again the main culprit. As in past years, our models tells us the IEA's demand underestimation continues to be located in the non-OECD world. As we have extensively discussed, when a country reaches a certain level of per-capita real GDP, oil demand starts to accelerate materially (our so-called "S-Curve" model). It's a trend most analysts fail to pick up. China has been the largest country to go through its "S-Curve" over the last 10 years, but our models tell us now India is beginning to enter its "S-Curve" as well (please see the India section of this letter for more details). Even if we assumed global oil demand only grows by an additional 300,000 b/d (to 1.6 mm b/d) , this implies that global oil supply must grow by 2.3 m b/d to prevent further inventory draws.

While the US shales will grow substantially next year, our modelling tells us they will not be nearly enough to make up this deficit. In its latest report, the IEA projects that total US production will grow by 1.1 m b/d in 2018. We are using this figure as our base-case assumption as well; however, we think forces are at work that will cause actual production to fall short of this figure-a subject we'll discuss soon. The rest of non-OPEC (including OPEC NGLs, biofuels and processing gains) is expected to grow by 600,000 b/d in 2018, driven entirely by new-project start-ups that were sanctioned nearly a decade ago in both Canada and Brazil. In particular, Suncor's Fort Hills oil sand mining project (originally expected to come online in 2011) is expected to finally reach commercial production in 2018 after extensive delays. While these projects will likely meet expectations, we believe non-OPEC production in other countries could disappoint materially.

As we wrote in the introduction, conventional oil discoveries have hit an all-time low. More important, we believe, is that consumption has now exceeded new discoveries for an incredible 18 out of the last 20 years. Although few analysts are commenting on it, we believe the lack of new discoveries is now taking its toll in several countries around the world, a trend we believe will accelerate in the next five years. In Mexico, for example, crude production has steadily and materially declined over the last five years. As of November, it stood nearly 780,000 b/d (or 26%) below its January 2013 level. Despite this half-decade-long decline, the IEA is now projecting that Mexico's full-year 2018 production will only be 80,000 b/d below its full-year 2017 level. That would require production to not only stop declining but actually grow by ~50,000 b/d from today's levels. Norway's oil fields are beginning to show signs of their age as well. Production there has declined by 14% in the last eight months alone (down 300,000 b/d since March). While some of this is explained by inclement weather in the North Sea, unexplained field maintenance (itself a function of field fatigue) was a large factor too. While a new platform is expected to commence operation early in 2018, we worry that the IEA's projections for 2018 are too optimistic (down only 70,000 b/d year-on-year and 1Q production that is 100,000 b/d higher than today). Instead of growing by 600,000 b/d in 2018, we believe non-OPEC production outside of the US will only grow by 400,000 b/d next year. As we mentioned earlier, the IEA has recently been overly optimistic in its expectations for non-OPEC production growth outside of the US. Since first making their prediction last summer, 2017 non-OPEC production ex-US has been revised down by nearly 250,000 b/d (after adjusting for the removal and addition of Indonesia and Equatorial Guinea to OPEC, respectively). In our next letter, we will discuss our global non-OPEC/non-US production model which clearly shows accelerating production declines in the next five years. Huge cuts in upstream capital spending combined with the collapse in new conventional discoveries will have an impact on non-OPEC/non-US production in the next five years—another further tightening to global crude oil markets that few analysts expect.

To summarize: from a starting deficit of 650,000 b/d in 2017, we expect global demand will grow by 1.6 m b/d, while the US will grow production by 1.1 m b/d and the rest of non-OPEC will contribute growth of 400,000 b/d. At its last meeting in November, OPEC agreed to maintain production cuts until the end of 2018, which if adhered to, would leave the global crude markets once again in deficit by 750,000 b/d for all of 2018. Global inventories would drop by another 250 mm bbl from today's levels, leaving inventories at a dangerous 140 mm bbl below the long-term average – the largest such deficit in our records. Even if OPEC were to completely reverse their 1.2 m b/d of production cuts at their June meeting, our models indicate this increased production would not be enough to fully balance the market for 2018 and inventories would continue to fall (albeit at a smaller rate). As inventories continue to draw, prices will continue to respond and could very easily reach $100 per barrel as market psychology switches from worries about surplus to worries about deficits. Oil market watchers may remember that in 2007, once OPEC realized it had cut production too much, it reversed all of its cuts in an attempt to stabilize the market. However, OPEC's increased production could not overcome inventories that continued to draw and psychology that had flipped. Even after OPEC began increasing its production in the summer of 2007, oil prices continued to advance, eventually surging by 90% in the next 12 months.

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Despite the oil balance math just outlined, we hear nothing but bearish talk on how US shale production growth will accelerate and swing the global crude market back into surplus. As we have just described for you, US shale growth would have to accelerate by 50% from here in order to even balance the market next year, let alone shift it into surplus. Our work tells us this is highly unlikely (if not impossible). Instead, the risk to US shale production in 2018 is to the downside. In our last letter, we presented several "Hubert Linearizations" for various shale plays in the US. Our work showed that analysts(and consensus opinion) are most likely overstating reserves in the Bakken, Eagle Ford, and Permian shale plays. We concluded that the Bakken and the Eagle Ford are in the early stages of field exhaustion and both fields run the risk of experiencing production disappointments going forward. While the Permian and the (much smaller) SCOOP/STACK are still in their "ramp up" phase, two of the three largest shale oil fields are potentially past peak production. We argued it would be very difficult to replicate the strong growth from the US shale plays experienced in the 2012-2014 period.

Since then, several industry veterans have made comments that confirm our views. There are few shale executives as insightful as Mark Papa. From 1999 to 2013, Mr. Papa served as the Chief Executive Officer of EOG Resources, where he was instrumental in proving the commercial viability of producing crude oil from shale. Mr. Papa led EOG to be a first-mover in both the Bakken and Eagle Ford. Mr. Papa now serves as the CEO of Centennial Development Corporation and, on their Q3 conference call, he explained how most analysts are underestimating what is happening in the Bakken and Eagle Ford today:

"Many people ascribe the reason for this tepid [US oil production] growth to be cash flow or service company limitations, but I think its lack of remaining Tier 1 geologic-quality drilling locations in two major oil shale plays of the three major oil shale plays, the Eagle Ford and Bakken. Even in a constructive oil price environment, I expect the 2018 total U.S. oil growth will be considerably less than the 1.2 million barrels per day to 1.4 million barrels per day that many people are predicting."

Mr. Papa went on to provide more color: "But I think if you look from the 30,000-foot level at the Bakken and Eagle Ford overall, I would say that they are no longer the growth engines that they were four years or five years ago, and that the majority of the Tier 1 quality locations have been drilled and there's just not that many to go. And if you suddenly got to an old price environment that, let's just say, turns out to be $70 WTI and you pump a lot of capital into the Bakken and Eagle Ford, the resulting production growth that you're going to see from current levels in those asset, I predict is going to be disappointingly low. But, clearly, you'll have individual wells from time to time that will be successful. So, you have to look at it from the macro view and not from an individual well view."

We believe Mr. Papa's comments bear close attention. Also, we find it extremely important that Mr. Papa's comments confirm what "Hubbert Linearization" tell us about both Bakken and Eagle Ford plays: neither field will be able to replicate the growth they achieved between 2010 and 2015.

A different energy executive, this time from the oilfield services side of the business, provided some interesting commentary in a meeting we attended during the quarter as well. He explained how, empirically, he had never in his career witnessed an oil field go on to make a new peak in production if it had not done so over the last three years. In other words, if a field peaked out at 1 mm b/d and subsequently declined to 900,000 b/d and was unable to again exceed 1 mm b/d in the next three years, it inevitably entered into a period of stagnation or persistent decline and the field never made a new production peak again.

While we do not have the data to definitively prove this claim, we have not been able to find a field that serves as an exception. From a conventional perspective, this observation holds true for the Daqing Field in China, the Samotlor and Romashkino fields in Russia, Prudhoe Bay in Alaska, the Thistle field in the UK, and the Permian basin. The closest thing we were able to get to an exception was the Cantarell field whose production hit 1.09 m b/d in 1991 before declining in 1992 and 1993 only to exceed the 1991 level again 1994 (in the third year post-peak). While this observation regarding peaks and three-year declines may seem more like anecdotal observations rather than a hard fact, it is particularly interesting because both the Eagle Ford and the Bakken achieved peak annual production in 2015 and if they do not exceed this peak this year (which we think unlikely), then history suggests they may have difficulty ever surpassing it again going forward. We also took keen interest in the corporate activity of a key Bakken producer. Oasis, long viewed as having some of the best Bakken acreage, recently decided to purchase Permian acreage from Forge Energy rather than deploy additional capital into North Dakota.

To be clear, we believe that total US production will still be able to grow materially from here. However, more and more data is emerging to suggest that both the Bakken and Eagle Ford have entered into a new "mature" phase of their developments and will not be the source of strong production growth they once were. If true, then it falls to the productive Permian and emerging SCOOP/STACK plays to shoulder the burden.

In our last letter, we detailed how onshore US production growth had experienced several months of disappointing production after having grown robustly at the end of 2016. In particular, we wrote that between February and July US onshore production grew by only 30,000 b/d per month, which represented a slow-down of 67% compared with the prior six-month period. We took this as evidence that our supply models were on the right track. Since then, the EIA has released new data that suggests US production accelerated again. However, we are skeptical because there are several oddities in the report and we question its accuracy. After a fairly average August, the EIA reported that onshore US crude production grew by nearly 300,000 b/d in September and 270,000 b/d in October – the two largest monthly growth readings since the entire shale revolution started. However, what makes the data suspicious is that the bulk of the acceleration came from conventional sources. After declining by 15,000 b/d per month on average for the last two years, onshore conventional crude production apparently surged by 173,000 b/d in September and another 108,000 b/d in October. (We calculate conventional production by taking total US crude production and subtracting total shale production from the EIA's Monthly Drilling Productivity Report.) Some of the gains are from Alaska which grew by 30,000 b/d and 24,000 b/d for September and October, respectively. These gains represent normal seasonal patterns for that state and will very likely revert in the next few months. However, the vast majority of the gains came from Texas and New Mexico conventional production (up 150,000 b/d and 60,000 b/d for September and October respectively). Quite simply, we do not see how this data could be accurate. Adding to our skepticism, the EIA in its most recent weekly data reported an apparent unexplained reclassification of 300,000 b/d of crude production into natural gas liquids, again pointing to potential problems with the dataset. We will monitor this situation closely, but we suspect that the EIA will end up revising conventional production lower in the upcoming months.

Shale production did accelerate somewhat in September and October, but its impact was much smaller than the reported surge in conventional production. The drivers of shale growth were the Permian, which we expected given the increase in the rig count and the Bakken which we had not expected. When we analyze the Bakken data further however, our models suggest that the September and October readings will likely not be repeated going forward. There is a certain amount of variability in the Bakken monthly data (owing to the extensive use of pad drilling) and when you compare September and October's data it becomes apparent that they were well within the bounds of "normal noise." For example, Bakken production growth of 62,000 b/d in October was driven by strong production per newly completed well which averaged 1,300 boe/d per well compared with ~800 boe/d per well on average for the previous six months. However, on five separate occasions over the last 18 months, we have seen a similar one-month spike to above 1,000 boe/d per well that was quickly reversed. Initial data for the month of November suggests that production per newly completed well dropped back down to 640 boe/d per well – suggesting that this most recent spike was once again not a sign of structural moves higher in productivity. Also, in parsing the Bakken data we came across another interesting observation. In our last letter we discussed the impact of "DUC liquidation" (or drilled-but-uncompleted wells) on production trends in the US shale plays. We explained that after a period of completing fewer wells than were drilled in 2015, this trend reversed itself in 2016. As a result, US shale production benefited from a one-time surge in production that we argued might not be replicated going forward. While most shale plays stopped "liquidating" DUCs in 2017 (due to increased drilling activity the Permian has started building a normal DUC inventory once again), the Bakken apparently has continued a massive DUC liquidation program. For the first eleven months of 2017, Bakken producers completed nearly 100 more wells than were drilled. This is an interesting observation for three reasons. First, our models suggest that as much as 35% of the growth from the Bakken in 2017 was the result of DUC liquidation and that without it, the play would have grown by 150,000 b /d, not the ~211,000 b/d actually reported. Second, the total number of drilled but uncompleted wells in the Bakken declined by 63% over the course of 2017. Since a certain number of DUCs will always be present in any active play, our models tell us that the magnitude of the DUC liquidation observed in 2017 is unlikely to be repeated and as a result production growth will likely slow. Lastly, the persistent DUC liquidation is simply one more sign that the Bakken is starting to "cool down." When activity accelerates in a play, DUC's tend to build (see the Permian), whereas when both drilling activity and corporate interest in a play begins to wane and activity decreases, companies liquidate DUC's. We believe continued DUC liquidation in the Bakken is further proof of the field's advancement into old age.

"ULTIMATELY, OUR MODELS TELL US THAT TWO OF THE THREE MAJOR SHALE PLAYS ARE NOW EXHIBITING EARLY SIGNS OF EXHAUSTION AND WILL NOT BE THE LARGE GROWTH DRIVERS THEY WERE LAST CYCLE. "

Ultimately, our models tell us that two of the three major shale plays are now exhibiting early signs of exhaustion and will not be the large growth drivers they were last cycle. Given the extremely tight oil balance today and our expectation for continued tightness throughout 2018, we believe that inventories will continue to draw down sharply. Ultimately, OPEC will need to increase production to try and help balance the market, but that will likely be done once prices move higher and the investor psychology has shifted from concerns of "surplus" to worries about "deficit."

Given how much there was to talk about this quarter, we did not touch on the rising technical and geopolitical risks facing OPEC today, but they are something we will discuss in our next letter. In particular, the recent political events in Saudi Arabia and Iran complicate OPEC discussions going forward, while the economic catastrophe in Venezuela has impacted crude production in that country. Such factors traditionally add an "uncertainty premium" to world oil markets and we will discuss them in great detail next quarter.

Also, please read ahead to our section on India where we will discuss in great detail our upcoming trip and several energy-related themes we will be exploring.

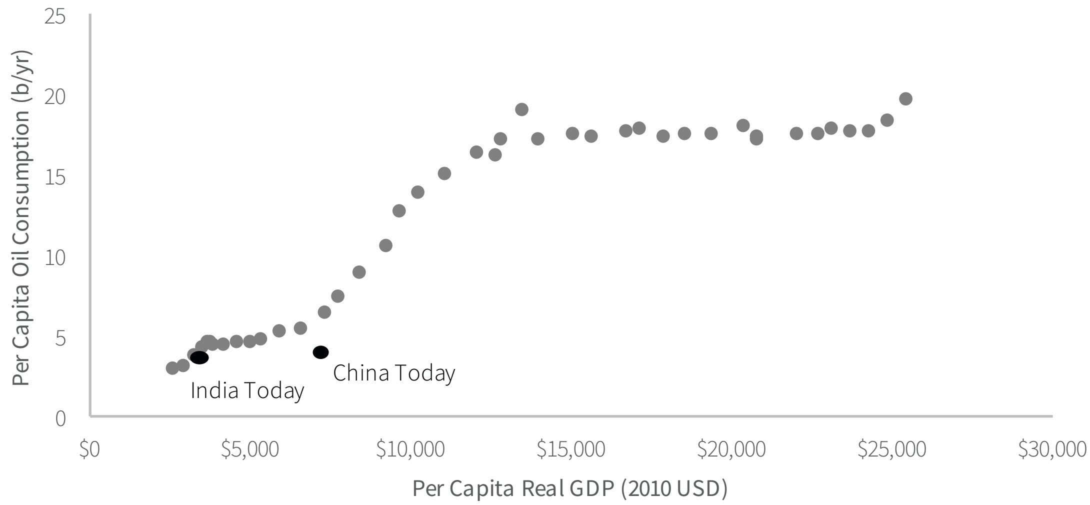
The global crude market continues to present investors with a once-in-a-lifetime opportunity. Incredibly bullish fundamentals combined with continued lack of interest by equity investors make oil-related securities our highest conviction investment theme going into 2018.

Is India Becoming the Next Major Source of Commodity Demand Growth?

Since 2000, natural resource investors has been fixated on China as the main source of demand growth -- for good reason. Over the last 18 years, China's oil demand has grown by nearly 10 mm b/d, representing 40% of total global demand growth in that period. Chinese total primary energy consumption has grown by 2 bn tonnes of oil equivalent representing over 50% of global growth. We started writing about China back in the early 2000s and built several models that helped us to predict China's explosive growth very early on. Readers will be familiar with our "S-Curve" models that explore the relationship between real per capita GDP and a country's oil demand. The most famous demonstration of an "S-Curve" model occurred in South Korea between 1970 and today. As you can see in the chart below, once a country hits a certain level of per capita real wealth (our so-called "S-Curve Tipping Point"), oil demand begins to rise very sharply. For example, between 1975 and 1985, South Korea doubled its real GDP per capita (measured in real US dollars from the year 2010) from $2,600 per person to $5,400 per person. Over the same period, per capita oil demand grew by 67% from 2.9 barrels per person per year to 4.8 barrels per person per year. At that point, South Korea hit its "S-Curve tipping-point" and oil demand skyrocketed. Over the next decade, real GDP per capita grew by 120% (from $5,400 per person to $12,000 per person) while per capita oil demand grew at twice that rate – an incredible 240%.

CHART 2 South Korea Oil S-Curve

CHINA TODAY VS. INDIA TODAY VS. SOUTH KOREA OIL S-CURVE



Source: BP Statistical Review, World Bank

Beginning in the middle of last decade, we wrote that China was on the verge of passing its "S-Curve Tipping Point," and that the consequences would have a similar impact. Sure enough, starting in 2001, Chinese oil demand growth began to accelerate. In 2001, Chinese per capita oil consumption grew by 0.02 barrels per year annually – a figure largely in line with trends of the previous 25 years. After China passed through its tipping-point in 2001, things began to quickly change. Between 2001 and 2008, Chinese per capita oil demand growth quadrupled. While we had been calling for this acceleration, it caught most market analysts off guard. In particular, once China hit its tipping-point, the IEA began to chronically underestimate Chinese oil demand in its Oil Market Reports. In fact, since 2003, the IEA has revised Chinese oil demand estimates on average each year by 300,000 b/d.

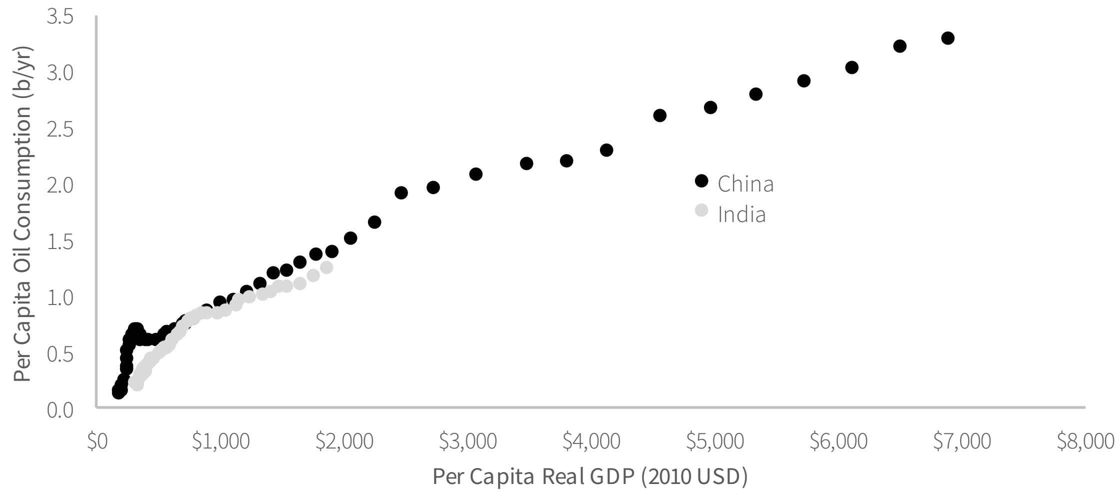
Much has been made of the fact that India will never become the "next China," for a variety of reasons. For example, while China has seen its oil demand grow by 7.7 mm b/d over the last 15 years, Indian demand has only grown by 2.2 mm b/d. Analysts often cite political differences (a particularly bureaucratic democracy vs. a centralized authoritarian regime) as a key factor explaining why India has not mimicked China's powerful growth. However, our models tell us something very different. While India does indeed face many challenges going forward, the bulk of the shortfall between India and China can be explained by India's lower level of economic development.

For example, India today is only just reaching the same level of real per capita GDP growth that China reached in 2001, when China first crossed its "S-Curve Tipping Point." Over the last decade, Indian per capita oil demand has grown by 0.03 barrels per year – the same rate as China between 1991-2001. In 2016, India's real per capita GDP averaged $1,900 while its oil demand was 1.2 barrels per person per year. These levels are both very similar to China in 2001 when China's real GDP per capita averaged $1,900 and oil demand was 1.4 barrels per person per year.

If India is in fact in the process of crossing its "S-Curve tipping point," what should we expect to see? If China is any indication, the first clue will be that analysts will begin chronically underestimating Indian oil demand. That is exactly what we see now. Over the last six months, the IEA revised up Indian oil demand going back to 2015 by 235,000 b/d on average and by as much as 370,000 b/d

CHART 3 China and India S-Curve

CHINA VS.
INDIA VS.
CHINA AND INDIA
S-CURVE



Source: BP Statistical Review, World Bank

for some quarters. We believe India is now beginning to exhibit accelerating oil demand growth, consistent with a country that has crossed its tipping-point,. If India has indeed crossed its tipping-point and, using China as a guide, then we should expect to see India grow its per capita oil demand by nearly 2 barrels per person per year over the next 15 years. This equates to 7 mm b/d of total oil demand growth over the decade or ~500,000 mm b/d per year – 67% higher than the IEA estimated in its most recent medium-term energy outlook.

Considering how important we believe India will become to global commodity markets, we have decided to travel to India at the end of February to conduct an in-depth research project. Over the years, we've taken trips to help form our views (particularly about China in the early part of the last decade). In particular, there are significant structural differences between India and China and we will try and explore how they will impact commodity demand growth over the coming decade. We will report what we find in our next letter, but we wanted to provide our readers with a preview of some of the issues we will be focused on.

Urbanization

One of the most important drivers of a country's commodity demand growth is the rate at which its population urbanizes. As a population moves from the countryside into cities, there is a dramatic increase in demand for both materials (to construct infrastructure and buildings) and energy. We recently finished reading *Vaclav Smil's Excellent Energy and Civilization: A History* (©2017 by Massachusetts Institute of Technology Press). Smil argues that the act of urbanization itself, apart from any associated industrial activities, leads to a large increase in energy consumption: "Living in large cities requires substantial increases in the per capita provision of energy even in the absence of heavy industries or large ports: the fossil fuels and electricity required to sustain a person who moved to one of Asia's new growing cities can be easily an order of magnitude higher than the meager amounts of biomass fuels used in the village of her birth to cook and (if need be) to heat a room."

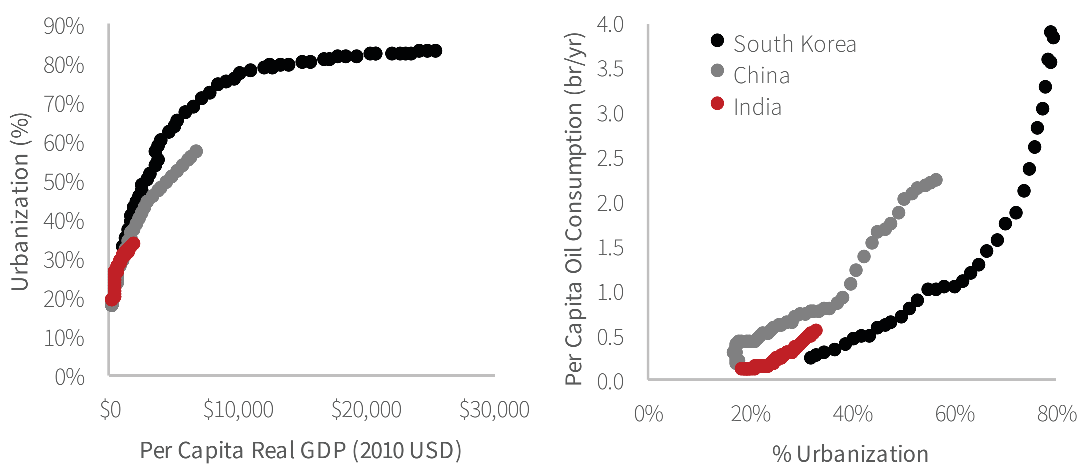
In South Korea, urbanization stood at 40% of the population in 1970 while primary energy consumption per capita averaged 0.4 tonnes of oil equivalent and real GDP per capita averaged $1,800. Over the next 15 years, as the country became more prosperous, its population urbanized substantially and by 1987 with real GDP at $6,500 per person, ~65% of the population lived in cities. Over that same period, primary energy demand per capita skyrocketed by 253%. China followed a very similar path. In 2000, with real per capita GDP of $1,800, 36% of its population lived in cities while 16 years later with real GDP per capita at $6,900, nearly 60% of the population was urbanized. Although China started from a higher level of per capita primary energy consumption (0.8 tonnes in 2000 compared with 0.4 tonnes in Korea in 1970), per capita demand nonetheless grew by nearly 200% as the country urbanized.

Today, India sits exactly where South Korea and China did in 1970 and 2000, respectively. With $1,900 of per capita income, 33% of its population is urban and total per capita primary energy consumption averages 0.35 tonnes of oil equivalent. Projections from the UN estimate that India could add 300 mm urban residents over the next 15 years which, assuming India's population continues to grow at 1.2%, would equate to a ~50% urbanization rate by 2030. In turn, this would suggest that total primary energy consumption will need to grow by between 160% and 270% (depending on whether India follows the South Korea Model or China model).

Will India be able to urbanize its population inline with expectations and how will this impact total energy demand? We will try to answer these questions in our upcoming visit.

CHART 4 Urbanization vs. GDP Urbanization vs. Energy Consumption

SOUTH KOREA VS. CHINA VS. INDIA URBANIZATION



Source: World Bank, Goehring & Rozencwajg Models

Expressways and Vehicle Penetration

A key driver of oil demand growth in China has been the sharp increase in total vehicle sales for both personal and industrial use. Major contributors to accelerating vehicle sales have been an increase in Chinese real GDP per capita, an increase in the urbanization rate, and a massive increase in the number of expressways across the country. As a country gets richer, the desire and ability of its people to drive an automobile increases. Similarly, as a population urbanizes, goods need to be delivered to urban centers, increasing the demand for trucks. Clearly a well-built expressway system is critical in allowing these trends to develop unabated.

In 2005 (the earliest data we have for auto sales), Chinese real GDP per capita averaged $2,800 and its total vehicle sales and vehicles in use per capita were 4.4 vehicles and 24 vehicles per 1,000 citizens, respectively. At that time, China was undergoing a massive infrastructure project to build out its expressway system. Between 2000 and 2016, China increased its expressway length by 8.5 times and we estimate that in 2005 total Chinese expressways totaled 32,000 miles. This equated to 8.7 miles per 1,000 square miles of land area, 40,000 citizens per mile of expressway, and 1,000 vehicles in use per mile of expressway. By 2016, Chinese expressways had exploded to 85,000 miles, or 23 miles per 1,000 square miles of land area and less than 20,000 citizens per mile. Vehicle sales outpaced expressway construction over that time and by 2016 there were 2,000 vehicles in use in China per mile of expressway.

By comparison, the expressway network in India is much smaller. As of today, with real per capita GDP of $1,900 there are incredibly less than 1,000 miles of expressways in India. With an area of 1.3 million square miles, this works out to just 0.7 miles of express per 1,000 square miles of land mass. Amazingly, India has 1.5 million citizens per mile of expressway (ten times the amount as China in 2000 with a comparable level of real GDP per capita). There are 31,000 vehicles in India per mile of expressway (32 times China's level in 2005).

In response to these staggering statistics, the Indian government has announced a massive expressway building program of its own. In the next five years alone, India plans on increasing its expressway system by a staggering 14 fold (albeit off of a very low base). By 2022, there are expected to be 13,000 miles of expressways in operation. While this is a step in the right direction, there will still be 100,000 Indian citizens per mile of expressway (twice the level of China in 2005). Given what we think vehicle sales could be over the next five years, there will still be upwards of 3,000 vehicles per mile of expressway.

Is India planning for a phase II expansion to its expressway system and, if not, what are the implications to vehicle rollout and economic growth more generally?

In addition to these questions, we will explore how India intends to meet its rapidly rising commodity needs, in particular, the nature of the country's electric generating and transmission system.

Precious Metals

In our Q2 2017 letter we outlined our belief that we were at the bottom of the cycle in commodity prices with a chart which plotted commodity prices against stock prices going back 100 years. The chart distinctly showed only three periods (1929, 1970, and 1999) where commodity prices had been as depressed relative to financial assets as they were in 2017. We theorized that, if 2017 turned out to be similar to those previous periods, huge outsized returns awaited those investors willing to make large contrarian investments in commodities. Since we wrote this essay six months ago, nothing has occurred to make us change our super-bullish commodity outlook. In fact, we are more bullish than ever.

We want to stress an important point about the upcoming huge bull market in commodities: it will include (and may even be led by) a huge bull market in gold and other precious metals. In each of the three previous periods of radical commodity undervaluation just mentioned, gold and silver investments fully participated or actually led the ensuing commodity bull market. In the great 1970 commodity bull market, both gold and silver were the best performing commodities during that decade. Although the oil bull market and its related shortages garnered the most headlines, the 1,000% gain in oil prices during the decade paled in comparison to the more than 2,000% gains experienced by gold and silver. In the great commodity bull market of last decade, both gold and silver kept pace with all other commodities. For example, between 2000 and 2010, copper wound up advancing almost 500% while oil was up over 500%. Gold and silver meanwhile kept up, advancing by approximately 450% and 500%, respectively. Even in the 1929 to 1947 commodity bull market, which encompassed both the Great Depression and World War II, gold again was the market leader. From 1929 to 1947, gold (reset in price by the Roosevelt administration in 1934) rose by 70%. In comparison, silver rose by 50%, copper by 30%, and oil by 50%. The only commodities to outperform gold during the 1929-1947 bull market were the grains. Prices for corn, wheat, and soybeans advanced almost 200%, 120% and 70% respectively from their 1929 price levels.

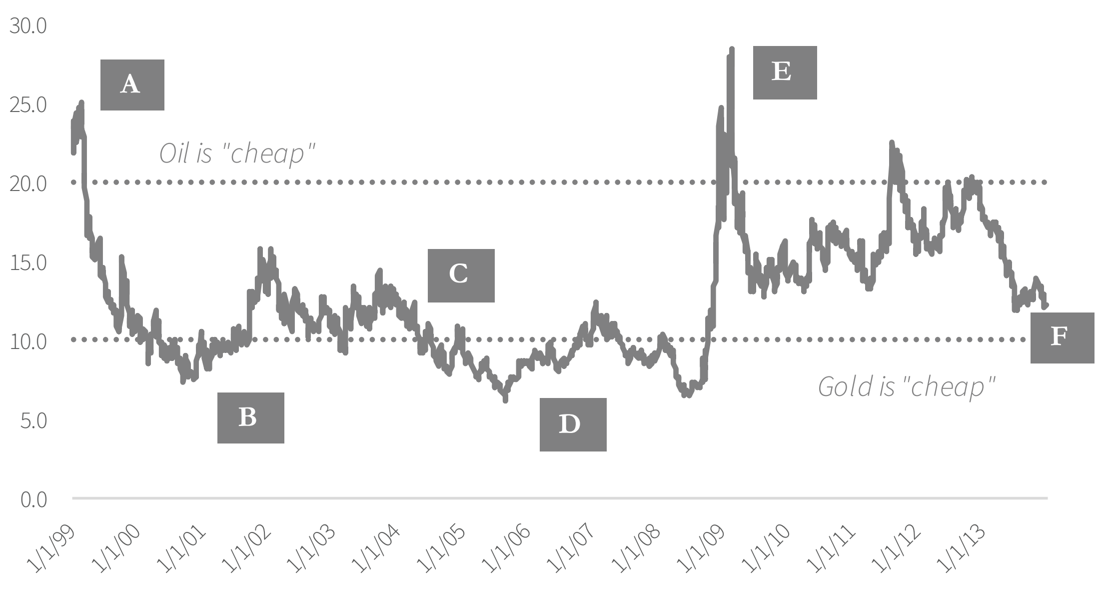
"WE WANT TO STRESS AN IMPORTANT POINT ABOUT THE UPCOMING HUGE BULL MARKET IN COMMODITIES: IT WILL INCLUDE (AND MAY EVEN BE LED BY) A HUGE BULL MARKET IN GOLD AND OTHER PRECIOUS METALS.

Because of unprecedented global money printing over the last ten years, we believe gold is radically undervalued today (please refer back to the "Gold Section" in our Q1 2016 letter where we discuss our valuation methodology). In that section, we explained that gold, priced relative to the number of US dollars outstanding, is as cheap as it has ever been, especially relative to its two previous episodes of cheapness,1970 and 2000. We are confident that a huge commodity bull market has begun and because we feel that gold and silver are radically undervalued, you might ask why we aren't recommending a maximum weighting in precious metal investments today. It's an excellent question and we will try to answer it, using the great 1999-2010 commodity bull market as a backdrop.

In that same Q1 2016 letter, we wrote a long essay on the historical relationship between oil and gold. Although few people agree with us, we have long believed there exists a very strong long-term relationship between the price of oil and gold. Given that oil has been by far the most important industrial commodity over the last 100 years (and still is today) and, given that gold continues to be the world's most important financial commodity, we believe there stands good reason for the two commodities to trade in some sort of relationship to each other. Going back all the way to 1858, we concluded that an ounce of gold has purchased, on average, eighteen barrels of oil, with a standard deviation of 8.4. In 1,920 monthly observations since 1858, gold has spent 90% of the time in a band where it has purchased between 10 and 30 barrels of oil. In the 1,920 monthly observations made since 1858, oil was radically cheap relative to gold (i.e., an ounce of gold bought 30 or more barrels of oil) only 5% of the time and, inversely, gold was radically cheap relative to oil, (i.e., gold bought 10 or less barrels of oil)only 5% of the time. In our essay, we made the observation that every time oil became cheap relative to gold (a gold-oil ratio above 30), oil went through a period of statistical outperformance versus gold, and in contrast, when gold was cheap versus oil (a ratio below 10), gold went through a significant period of outperformance versus oil. As you might remember, back in Q1 of 2016, a period where near-panic selling gripped oil markets, the gold-oil ratio hit an all-time high of 47, surpassing the old gold-oil ratio peak of 39 set in 1933 in the depths of the Great Depression. We used this new record in the gold-oil ratio as evidence that the oil bear market was over, a major bottom in oil had been made, and that oil represented a better investment compared to gold for the foreseeable future. Since we wrote this, oil has indeed significantly outperformed gold (135% versus 25%) however, it should be mentioned that because of the huge bearishness that has gripped energy markets, energy stocks (as measured by the XOP ETF) have only advanced 60% versus a 90% return on gold stocks (as measured by the GDX ETF). With today's gold-oil ratio now at 21 (the gold oil ratio almost hit 30 again last summer), we still believe oil (and oil stocks) remains cheap relative to gold, that oil will continue to outperform gold, and that oil stocks, which have lagged significantly the oil price, will be better investments than gold and gold-related equities. However, at some point in the not-too-distant future gold will once again become undervalued relative to oil and gold-related investments will again become market leaders.

To understand our thinking, let's go back to the last great commodity bull market and look at what observations we could make to help us time the switch from oil into gold in this upcoming bull market. In the great 1999 to 2011 commodity bull market, the gold-oil ratio swung from one extreme to another multiple times and, in each instance, the extremes reached in these ratios represented great times to rotate exposure from oil to gold and then back again. Just like what happened in the 1999 to 2011 commodity bull market, we believe clear signals will emerge again to help us make insightful and profitable decisions regarding the right time to make changes to our investment positioning. Let's step back, review, and analyze what happened to the gold-oil ratio between 1999 (the beginning of the great commodity bull market) and 2011 (its end) and let's construct a roadmap we can follow for this upcoming opportunity.

CHART 5 Gold Oil Ratio



Source: Wood Mackenzie, Goehring & Rozencwajg Models

	Date		Ratio		Return		
Period	Start	End	Start	End	Gold	Oil	Relative
A --> B	1/1/99	9/19/00	23.9	7.5	-5.4%	203.0%	208.4%
B --> C	9/19/00	12/31/03	7.5	12.8	52.7%	-10.9%	-63.6%
C --> D	12/31/03	12/31/05	12.8	8.5	24.4%	87.7%	63.3%
D --> E	12/31/05	12/31/08	8.5	19.8	70.6%	-26.9%	-97.5%
E --> F	2/18/09	12/31/13	28.4	12.3	22.4%	184.3%	161.9%

In retrospect, we know the collapse of oil prices that took place at the end of 1998 was the tip-off that the great 20-year commodity bear market, which started in 1980, was drawing to a close. Oil hit $11 per barrel in January of 1999 and, with gold prices at $290, the gold-oil ratio almost hit 30, representing a period of extreme cheapness of oil relative to gold. Given the extreme cheapness of oil to gold, we should have seen oil significantly outperform the metal, which it did. From its bottom in January 1999, oil appreciated 200% (from $11 to $37 per barrel) in the following 18 months, whereas gold actually fell by 5% during the same time period (from $290 to $275 per ounce). Also, energy stocks significantly outperformed gold equites. For example, the XLE (the Energy Select Sector Index) outperformed the HUI (the NYSE Gold Bug Index) by almost 95% (the XLE rose 50% and HUI fell almost 40%). The huge outperformance of oil versus gold swung the gold-oil ratio from radical cheapness of oil to gold to radical cheapness of gold to oil. By Q4 of 2000, the gold-oil ratio had fallen to 7 indicating that gold was about as cheap as it ever gets relative to oil. The radical cheapness of the gold-oil ratio suggested gold and gold-related equities should significantly outperform oil over the next several years. That is indeed what happened. Between Q4 of 2000 and the end of 2003, gold appreciated by almost 55% (from $275 to $400 per ounce) while oil traded sideways with no return for three years. But the real outperformance occurred within gold equities. Gold equities outperformed energy-related equities by a massive 520% over the three-year period. The HUI Index rose a massive 510% over the three years whereas the XLE fell by 10%.

By the end of 2003, the large outperformance of gold relative to oil meant that the gold-oil ratio had advanced back up to 13 (oil at $30 and gold at $420). Although the indicator told us that oil and gold were in "neutral" valuation relative to each other, it did signal that another reversal in performance was about to take place between the two commodities. From the start of 2004 to the end of 2005, oil advanced by almost 100% (from $30 to $60 per barrel), whereas gold only advanced by a little over 25% (from $420 to $510 per ounce). Again, energy stocks were the better investment during that two- year period. The XLE advanced over 90% in 2004 and 2005, whereas the HUI advanced less than 25%.

By the end of 2005, with oil prices having surged, the gold-oil ratio had once again swung back into territory where gold was radically undervalued relative to oil. With gold at $500 and oil at $60, the ratio nearly reached eight times by the beginning of 2006, which once again strongly suggested that gold-related investments should significantly outperform oil investments. Again, they did. From the beginning of 2006 to the end of 2008, gold appreciated by 70% (from $500 to $850 per once) while oil prices actually fell nearly 30% (from $60 to $40 per barrel). We should point out that when oil hit $142 per barrel in July 2008 during a massive short squeeze, the gold-oil ratio hit its lowest level ever reading of six times – a clear tipoff that oil, at $140 per barrel, was radically overvalued. Although gold significantly outperformed oil by almost by 100% in the 2006-2008 period, both the XLE and HUI returned little during the same time period. With the 2008 financial crisis-related crash of oil prices and, given the surge in gold prices, by the end of 2008, oil had again reached undervalued territory relative to gold. In February 2009, with oil falling to $35 per barrel and, with gold approaching $1,000 per ounces, the ratio almost hit 30. Although gold continued to perform well over the next three years, eventually topping out at $1,900 per ounce in at 2011, oil was a far superior performer over the full five-year stretch. From the beginning of 2009 to the end of 2013, oil advanced by 185%, whereas gold advanced by only 22%. Energy-related equities also significantly outperformed precious metal equities over the same five year period. For example, the XLE advanced over 100% while the HUI actually fell 10%.

Also we think it's important to note the gold-oil ratio never retreated below 14 during the entire five-year stretch after January 2009. Gold never became undervalued relative to oil after 2009 and oil remained the superior performing asset class.

"AS INVESTORS, WE LOVE OIL HERE, AND WE LOVE PRECIOUS METALS TOO. HOWEVER, BASED ON TODAY'S GOLD-TO-OIL RATIO, (IT ALMOST HIT 30 LAST SUMMER, AT TODAY IT STILL STANDS AT 21), WE BELIEVE THAT OIL WILL CONTINUE TO OUTPERFORM GOLD."

We go through this exercise to show how we believe an investor who is bullish towards both oil and gold should plan their investment strategies in the upcoming bull market. If the upcoming commodity bull market in any way resembles the 1999-2011 bull market, we believe there will be excellent periods to both increase and decrease one exposure to precious metals versus other commodities. As investors, we love oil here, and we love precious metals too. However, based on today's gold-to-oil ratio, (it almost hit 30 last summer, at today it still stands at 21), we believe that oil will continue to outperform gold.

We believe we are repeating the 1999-2000 experience in what will be recognized as the first leg of the next great commodity bull market. After the gold-oil ratio hit 30 at the beginning of 1999, oil and oil-related equities significantly outperformed gold and gold-related equities for the next two years. The sliding of the gold-oil ratio from extreme cheapness of oil relative to gold in the beginning of 1999 to the extreme cheapness of gold relative to oil-at the end of 2000, signaled that investors should aggressively switch from oil into gold. Looking at what happened between 2001 and 2003, we know in retrospect that making the switch was the correct thing to do: gold and related equities radically outperformed oil and their related stocks by huge amounts.

In this commodity bull market, oil has performed exactly as we thought given the surge in the gold-oil ratio that took place in the beginning of 2016. Our research correctly predicted that the global oil market would slip into deficit in 2016. Oil-related stocks have lagged the oil price by record amounts in 2017, however, we believe that oil-related stocks will surge in 2018 when investors realize many of the bearish issues brought up last year will not come to pass. Our fundamental analysis tell us that triple digit-oil prices are a strong possibility in 2018. Combining our strong oil price forecast with observations regarding the complete lack of gold interest from western investors, as evidenced by little physical gold or silver accumulation through the ETFs, we believe that oil will continue to outperform gold.

However, given our belief that oil is going significantly higher in the next 12 months, we also believe the gold-oil ratio will swing to a point that gold will be significantly undervalued relative to oil, just like what happed back in the early part of the last great commodity bull market. At the point, based on additional fundamental research to back our decision, we expect to make a significant increase in our exposure to investments in precious metals.

We believe gold and all precious metals will experience a huge bull market in the coming years. Gold is just too undervalued relative to the huge amounts of money that have been created by central banks in the last 10 years. However, looking back through history, we do know that the performance between gold, oil and all commodities can vary wildly and, as value changes relative to each other, both excellent buying and selling opportunities often emerge. We showed how oil and gold swing from undervalued to overvalued and back to undervalued multiples times in the last bull market, and it made sense to switch from one commodity into the other and then back again. We will carefully chronicle these relationships, and will make changes in our investment positioning that maximize our profits. The huge bull market in gold is getting closer and we aim to be fully exposed when the great buying opportunity arrives.

Uranium Market

Uranium is a commodity that we have long followed and over the last 25 years it's a market where we have had significant exposure. Over the last 10 years the price of uranium has collapsed. From its peak of $150 / lbs reached back in 2007, uranium prices touched $19 / lbs last summer—a decline of almost 90%. We believe that a number of factors are at work in today's uranium market that will make uranium and related securities excellent investments in the coming years. Prices have collapsed in a long-grinding bear market, investors have absolutely no interest in the metal, and significant changes have taken place in global uranium market's supply and demand that few have noticed.

On October 7, 2017, a very important article appeared on the front page of The New York Times that we believe has huge implications for the nuclear power industry and uranium. The headline read: "Germany's Shift to Green Power Stalls, Despite Huge Investments." As many of you know, Germany has been at the forefront in making investments in electricity generated from renewable sources. Over the last decade, Germany has spent huge amounts of capital and through generous subsidies now has installed enough capacity to generate almost 40% of its electricity needs from renewables—that is when the sun is shining and the wind is blowing., However, the massive investment in renewables (primarily wind and solar) have come with huge costs that are today becoming unsustainable. For example, electricity rates to German residential users have soared by 100% since 2010; Germans pay some of the highest electricity rates in the world today. What's most important, the huge investment in renewable electricity generation has not helped Germany attain what it wants most: a reduction in CO_2 output. Germany has long been in the forefront of calling for aggressive international CO_2 limits. It has pledged to cut its carbon emission 40% below its 1990 level, one of the boldest targets in the world. However, with the 2020 CO_2 reduction goal looming, Germany now finds itself in the embarrassing position of being nowhere close to attaining its ambitious goal. In fact, the latest data points indicate that Germany is going in the wrong direction--its 2016 CO_2 output was actually higher than what the country produced in 2010. Massive subsidies were given not only to producers of renewable electricity but to large industrial users who would be uncompetitive on a global basis if they had to pay the real cost of electricity. With the surge in electricity rates that were needed to pay for these subsidies and, the most important goal of all—the reduction in CO_2 output --falling quickly out of reach, it's not surprising that a political revolt is taking place in the country. The far-right AFD party, which won enough votes in the most recent election to enter Parliament, has called for an immediate exits from the "Energiewende"—the subsidy program that encourages investments in renewable electricity generation.

We write about Germany's renewable odyssey for two reasons. First, as we have written before, the adoption of the electric vehicle only makes sense if the electricity needed to power these vehicles comes from either a renewable (sun and or wind) or a "clean" source. Burning hydrocarbons in an internal combustion engine (especially a diesel) produces less CO_2 than generating electricity at a hydrocarbon-fueled plant, transmitting it, and then turning it into a vehicle's forward motion. However, as Germany has clearly demonstrated, making the huge investment in solar and wind needed to potentially power an economy that might someday widely adopt the electric vehicle, has produced results that are conflicted: electricity costs have skyrocketed, and CO_2 output, instead of falling, has actually increased. As The New York Times article succinctly put it: "As a clean energy pioneer, Germany has not always seen the result it desired from its heavy spending."

Second, Germany's experience highlights the problem of producing electricity from unreliable renewable sources. For an electricity grid to function reliably when 40% of electricity is sourced from unreliable sources, huge investments have to made in back-up generating capacity. In this regard, Germany has made its investment in renewables even more challenging. After the Fukushima nuclear accident, Germany decided to accelerate the phase-out of it nuclear power. This has made the country more reliant on its coal-fired power stations. Nuclear power used to supply 25% of Germany's electric power, but that is now in terminal decline. Coal consumption in Germany has grown by 10% since 2010 as the country relies more and more on coal-fired plants to provide base-load and back-up capacity.

The power situation in Germany is extremely complicated, but we believe it provides an excellent demonstration of the inability to maintain an electricity grid, powered by renewables, that doesn't have a "clean" source of back-up power: costs skyrocket, and CO2 output increase. Unless new breakthroughs are made in storage technology, we believe that nuclear power will provide the only long-term solution to an economy that wishes to force the adoption of electric vehicle that will be powered by electricity generated from renewable sources. The German experiment has already told you what that world will look like if the nuclear path is not taken. Massive investments will be made, electricity prices will surge, CO2 output will increase, and potential political dislocations could occur. In Germany's case, a far right party has emerged with its primary goal the roll-back of renewable power investment and generation. If Germany had decided to produce 40% of its electricity in renewables while at the same time increasing investment in nuclear power generation with a target of 40% of total electricity produced, electricity rates would still have doubled, but CO2 output would have fallen significantly as coal consumption significantly declined. We believe the German example clearly shows that to be "green" without nuclear power will be an expensive experiment that eventually creates more problems than it solves. We believe the global nuclear generating business has an extremely bright future.

"OVER THE LAST 10 YEARS, JUST ABOUT EVERYTHING THAT COULD GO WRONG IN GLOBAL URANIUM MARKETS HAS GONE WRONG."

Over the last 10 years, just about everything that could go wrong in global uranium markets has gone wrong. The largest shock was the Fukushima nuclear disaster that occurred back in March 2011. As most will remember, the city of Fukushima was hit with a massive tsunami generated by a 9.0 magnitude earthquake occurring 200 miles off eastern Japan. The resulting tsunami damaged the pumping capability of the three Fukushima reactors which then lost water circulation and overheated. All four nuclear reactors at Fukushima were severely damaged and the three reactors that were operating at the time of the tsunami experienced full-core meltdown. The subsequent release of radiation from the disaster was minimal and no deaths as of today have been attributed to the event.

Prior to Fukushima, Japan had 50 reactors in operation and 30% of the country's electric power was generated form nuclear power. In 2010, Japan consumed approximately 20 mm lbs of U3O8, (the primary input used in nuclear power heat generation), representing close to 15% of world uranium consumption. Subsequent to Fukushima, all Japanese nuclear reactors were shut down and, since 2011, only five reactors have restarted with 21 reactors today in the process of restart approval. We calculate 120 mm lbs of Japanese uranium demand has been lost since Fukushima, which has caused global U308 inventories to swell and prices to come under severe pressure. Also following Fukushima, the German government announced that it was undertaking a policy of eliminating its nuclear power generating capability. In 2011, Germany operated 17 reactors which generated 25% of the country's power. Germany in 2010 consumed approximately 9 mm lbs of U308, representing approximately 6% of world demand. Since 2011, nine nuclear reactors have been shut which we calculate has reduced global uranium demand by an additional 5 mm tonnes per year. Since Fukushima, global uranium demand has declined by approximately almost 25 mm lbs per year (or almost 18%).

Since 2011, two big supply "shocks" have put further downward pressure on uranium prices. First the massive Cigar Lake facility by Cameco in northern Saskachawan was commissioned. Although delayed for years because of water incursion problems, Cigar Lake finally commenced operation at the end of 2014 and has now reached full production of 16 mm lbs of annual production. Cigar Lake's production added almost 10% to world mine supply since 2014.

The second supply shock came from Kazakhstan. Since 2010, Kazakhstan has undergone a massive expansion of its uranium production capacity, primarily form in-situ leaching. In 2007, Kazakhstan produced approximately 17 mm lbs of uranium which represented about 15% of world mine supply. By 2016, however, the country's production had surged to almost 55 mm lbs, which now represent almost 40% of world mine production. World uranium mine production in 2007 was approximately 107 mm lbs. By 2016, world mine production had increased by 55 mm lbs to 172 mm lbs. Production from the start-up of Cigar Lake and massive expansions in uranium production from Kazakhstan represented 100% of the increase in world mine production since 2007.

Demand shocks and supply issues has pushed global uranium markets into surplus and prices have plunged. From the mid-1990's to the mid-2000's, the world consumed on average approximately 120-140 mm lbs. of uranium per year and world mine production average approximately 75 mm lbs. The huge gap that emerged between demand and world mine supply was satisfied by huge amounts of secondary supply— primarily from the reprocessing of old Soviet-era nuclear stockpiles. When the supply of these secondary stockpiles began to decrease in 2000, uranium prices entered a huge bull market. Price reached a low of in $9/lbs. in 2002 and eventually spiked to almost $150/lb in 2007.

Today, global demand, even with losses from Japan and Germany, has almost approached 155 mm lbs, but surging mine supply (now at 162 mm tonnes of supply) has caught up with global demand. Additionally, 35 to 40 mm lbs of secondary uranium supply (again from reprocessed nuclear weapons grade fuel) continues to enter global markets. Adding mine supply to supply from secondary sources, we calculate global uranium markets to be over-supplied by approximately 45 to 50 mm tonnes. In response to this surplus, uranium prices today have declined almost 90% from their 2007 highs.

"ALTHOUGH THE URANIUM MARKET IS IN SURPLUS TODAY, ACCORDING TO OUR RESEARCH, THE MARKET IS ABOUT TO BE THROWN BACK INTO STRUCTURAL DEFICIT."

Although the uranium market is in surplus today, according to our research, the market is about to be thrown back into structural deficit. At today's uranium price ($23 / lb), we calculate that almost half all world mines supply is now operating at cash losses. Clearly, this is unsustainable and already two big supply cut-back announcements have been made. First, Cameco, one of the world largest producers, announced it was suspending production at its McArthur River mine starting in January

2018. McArthur River produces almost 15 mm lbs of uranium, so this reduction represent approximately 10% of world supply. Cameco will meet its sale commitments from its own inventory. Then is November, the national uranium company of Kazakhstan ("KAZ") announced it was cutting its production by 20% for three years. A significant portion of Kazakhstan's production in now losing money, so an announcement such as this should come as no surprise. "KAZ"'s announced cuts amount to almost 9 mm tonnes of annual supply, which represent another 6% of global supply. The McArther River and "KAZ" production cuts will reduce 2018's surplus to only 20-25 mm lbs. Although the uranium market is still in surplus, we believe this surplus will be absorbed by extremely strong demand in the next several years.

Although nuclear power development is dying here in the west (the disastrous cost overruns at both the Vogtle projects in Georgia and the Virgil Summer project in South Carolina have most likely killed any further expansion of nuclear power in the Unites States), nothing could be further from the truth in the rest of the world.

One of the strongest areas of uranium demand will come from China. Widely publicized reports of air quality, (primarily from burning coal to generate electricity) combined with China's stated desire to reduce CO2 emissions (China signed the 2015 Paris Agreement), means that China has no alternative but to expand its already massive nuclear power plant construction plans. Given Germany's experience outlined in the beginning of this section, we believe that nuclear will be a huge component of China's Co2 reduction strategy, especially as China also has huge renewable expansion plans. China today has 37 reactors in operation and an additional 20 reactors are under construction. Plans are for 58 G. We of nuclear generating capacity to be up and running by 2020-2022, which is an increase of 70% from today. China plans to triple (to 150 GWe) nuclear generating capability by 2030. At that point nuclear power would represent only 10% of China total generating capacity (up from 3% today). After 2020, China has stated that it wants to add an additional 300 GWe of nuclear generating capacity after 2020. China's ultimate goal is for nuclear power to generate 15% of the county's total electricity needs. Plans include the commissioning of six to eight plants per year between now and 2020 and to accelerate this to 10 plants per year after 2020. In 2016, we estimate China consumed approximate 12 mm lbs of uranium, representing less than 8% of world demand. Given the growth profile we just outlined, we estimate China's uranium consumption will more than quadruple—to almost 50 mm lbs in the next 13 years.

"BUT CHINA IS NOT THE ONLY COUNTRY WITH HUGE NUCLEAR AMBITIONS: INDIA DOES AS WELL."

But China is not the only country with huge nuclear ambitions: India does as well. Because of strong economic growth, and a reliance on coal, India has already run into severe air quality issues. "Choking on Air in New Delhi" reads a November 12, 2017 headline on the front page of The New York Times. Just like China, India will have to make huge investments in nuclear power if it wants to improve air quality and reduce CO2 emissions—less of an issue for India which did not sign the 2015 Paris Agreement. India today has 22 nuclear power plants operational which represent approximately 3.5% of the country's total electricity generating capacity. India plans to double the number of commissioned nuclear plants by 2024 and long rang-goals call for nuclear power to supply 25% India's estimated electricity consumption by 2050. India will need a significant number of newly commissioned nuclear power plants to attain their goals.

At the start of 2018, 160 nuclear reactors with total gross capacity of 170 MWe are either in construction, on order or planned. This 170 MWe represents over 40% of today's operating nuclear generating base. On top of these 160 reactors an additional 300 reactors are proposed.

Given the capacity expansion plans just outlined and assuming 65% to 70% of Japan's nuclear power generating capability comes back on line, we model global uranium demand to increase from 155 mm lbs. today to almost 250 mm lbs. by 2030. We believe that the uranium market is still in surplus by approximately 20-30 mm lbs, even after the Cameco and "KAZ" cuts. However, China and India in a massive expansion of nuclear plant construction and, given that uranium mine supply will actually begin to decline in the next several years, we model that the uranium market will slip into deficit by 2019 and that deficit will widen significantly as we progress through the next decade. In fact, based upon our modelling, we believe that the structural gap between global demand and global mine supply will reach over 100 mm lbs by mid-next decade, a gap much larger than what existed in 2000 when the last great uranium bull market began. Throughout the 1990s and the early 2000s the structural gap between demand and supply in global uranium markets was met by huge inventories of reprocessed weapons grade fuel, much of it coming from the former Soviet Union. Although global inventories have increased (primarily due to the Japanese who continue to take delivery of pre-Fukushima uranium), we believe that global inventories are far more manageable than they were 20 years ago in the last uranium bear market.

Demand for uranium is growing steadily and the renewable experience in Germany clearly shows that huge investments in renewables accomplish little, if back-up power in not generated from a clean source such as nuclear. Uranium supply has now been cut and our modelling tells us that the global uranium markets will enter a long period of structural deficit starting in 2019. We believe uranium markets and related investments have bottomed and have excellent appreciation potential.

Copper

Copper prices continued to rally strongly in Q4, rising an additional 12%. For the year, copper prices have risen almost 32%, matching the performance of aluminum which rose 34%.

During the quarter, global copper inventories continued to fall. Copper inventories on the Shanghai, London Metals Exchange, and the COMEX finished at 544,000 metric tonnes, down approximately 6.8% from the end of Q3 of 2016. On the demand side, global copper consumption has slowed from the strong growth we saw in 2016, but it still remains in positive territory. According the World Base Metal Statistics bulletin (WMBS), China's copper consumption for the first 10 months of 2017 grew at just .4%, down significantly from its 6% in 2016. We believe our research tells us that China's copper consumption has many years of strong growth, so this soft patch in demand growth doesn't concern us. Outside of China, the rest of the non-OECD world continues to see strong growth. According to the WBMS, non-OECD (ex-China) copper demand has grown 2.4% in the first 10 months of 2017. In the OECD world (now representing only 33% of total world demand), WBMS statistics indicate copper consumption has fall 1.8% for the first 10 months of 2017 versus 2016. Overall, global consumption is flat for the year. Using our modelling of copper demand in the non-OECD world and given the continued push in many markets for the adoption of the electric vehicle, we believe that copper consumption will continue to growth strongly. For those interested in our views regarding copper demand, please check out the copper section of our website, where all our research can be found.

However, the real surprise in global copper markets has been the slowdown in global copper mine supply growth. As readers know, we strongly believe that extrapolation of extremely strong copper mine supply growth in 2015 and 2016 was a mistake, and that we should instead experience a long period of little growth in copper mine supply. The big slowdown in the expansion and commissioning of new projects, combined with continued acceleration of base depletion, means that the world should see little increase in copper mine supply between 2016 and 2020. This scenario looks to be playing out. According to the WMBS, monthly copper supply has now been flat for almost two years and, according to our modeling, we believe that we should continue to see little copper mines supply growth for the next three years.

We remain bullish on copper, and believe it has by far the best supply demand fundamentals of any base metal. Base demand (driven by strong demand in the non-OECD world), enhanced by governments' push to increase the use of electric vehicles (which require an intensity of copper consumption few investors appreciate), combined with a significant slowing of global mines supply, means that the copper market has fallen into structural deficit. Copper prices have now risen almost 65% off their 2016 lows, but we believe this is only the start of the copper bull market. We continue to recommend large exposure to copper related markets.

North American Natural Gas

North American natural gas prices were volatile during the quarter, as extreme winter weather across the United States drove demand to record levels while production continued to grow materially. Natural gas prices (as measured by the NYMEX prompt month Henry Hub contract) rallied as high as $3.21 per thousand cubic feet, then sold off to as low as $2.60 before ending the quarter largely where they started at $3.06. Prices for physical delivery into New York recorded an all-time record high prices of $175 per thousand cubic feet during the worst of the cold weather before quickly settling back. While these prices certainly grabbed attention, they are very transitory and reflect real-time regional bottlenecks more than true underlying fundamentals.

Winter weather dominated the headlines as a cold snap gripped both the Northeast as well parts of the Southern United States during Q4. While temperatures for the quarter as a whole were only 2% colder than normal (as measured by Heating Degree Days), December in particular was 10% colder than normal and approached the levels witnessed during the Polar Vortex in December 2013.

Driven by increased heating demand, US natural gas inventories drew by a substantial 382 bcf during the quarter and now stand at 357 bcf below the five-year average levels – more or less in line with the 2013-2014 "Polar Vortex" inventory levels at the comparable time in the winter. As followers of the natural gas market will recall, natural gas prices continued their rally into 2014 as the cold weather persisted and eventually reached a high of $6.15 by February. For 2014 as a whole, natural gas prices went on to average $4.26 (the second highest annual reading since gas prices collapsed in 2008) as inventories eventually declined to 1 tcf below average.

"WHILE SOME BELIEVE WE MAY BE REPEATING THE 2013-2014 EXPERIENCE, SOMETHING DRAMATICALLY DIFFERENT IS TAKING PLACE IN THE NORTH AMERICAN NATURAL GAS MARKET TODAY COMPARED WITH FOUR YEARS AGO, A DIFFERENCE THAT MAKES US MUCH MORE CAUTIOUS."

While some believe we may be repeating the 2013-2014 experience, something dramatically different is taking place in the North American natural gas market today compared with four years ago, a difference that makes us much more cautious. Over the six-month period ending December 2013 US dry gas production had grown by 700 mmcf/d whereas today (October 2017 -- the most recent data available) production grew by nearly 3.5 bcf/d compared with six-months earlier. More troubling still, this acceleration will only get more severe as surging production from the Marcellus and Utica is joined by additional volumes coming from the gas-rich Delaware section of the Permian Basin and the SCOOP/STACK.

A significant portion of the winter heating season lies ahead of us. While temperatures remain cold as we write this letter, there is no indication that the remainder of the winter will be as cold as the winter of 2013-2014. To make that assumption seems risky.

We will continue to monitor the natural gas market very closely for any signs that the incredibly robust production growth is abating, but given the impressive volumes we are seeing today (with a rig count that still remains 60% lower than it was five years ago), we continue to much prefer oil and oil-related investments.