ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

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Note: *Musings from the Oil Patch reflects an eclectic collection of stories and analyses dealing with issues and developments within the energy industry that I feel have potentially significant implications for executives operating and planning for the future. The newsletter is published every two weeks, but periodically events and travel may alter that schedule. As always, I welcome your comments and observations.* Allen Brooks

Issues With The Energy Transition To Green Energy

"The rest of the world views oil and gas differently than Houston"

"The rest of the world views oil and gas differently than Houston. If you don't realize that, you will have problems." That warning came from a speaker discussing the ongoing energy transition. At the heart of the issue of managing the shift in how the world's energy system should be fueled is the belief that by shifting from one predominantly fossil-fuel-based to one totally renewables-based will result in a reduction in carbon emissions that will solve global climate change. To those promoting this view, and especially for the politicians mandating it, this switch can happen quickly and be relatively costless. Based on recent reports, as well as our monitoring panel discussions at a recent energy conference, this assumption is far from reality, and dangerous in its application.

Transitioning our energy mix involves significant technical, as well as economic considerations, with the former often being diverted by the latter. At the 6th Annual Global Oil & Gas Institute meeting hosted by global law firm Baker McKenzie, a panel discussed the topic: Big Oil to Big Energy: Impact of Energy Transition on Oil & Gas. Since the meeting was held under Chatham House Rules, we are not able to attribute statements to specific speakers, but we can characterize their views. The panel had two speakers. One was an officer of the international commodity trading company, Vitol – a privately owned company headquartered in Switzerland that generated $230 billion in revenues last year. It actively trades 7.5 million barrels per day, or roughly 8% of the world's daily oil consumption, so it is a player in the market. It is involved in virtually every aspect of the oil business. The second speaker was a lawyer from the U.S. operations of BP plc (BP-NYSE), one of the world's largest integrated oil companies, which has a growing renewables business and has committed to doing more in clean energy.

There are geographical differences in attitudes towards the transition of our energy system due to climate change

A point made by the BP lawyer was that there are geographical differences in attitudes towards the transition of our energy system due to climate change. The fear of its impact on regions is quite different, but as he stated, the views of the U.S. and European Union (EU) are coming closer together. He pointed out how views about climate change have changed over the past 20 years. In 1998, the Kyoto Protocol was never presented to the United States Senate for approval, as the body had previously voted 95-0 for a resolution preventing this country from signing any protocol mandating the reduction of greenhouse gas emissions unless it also required reductions from developing countries during the same period. Today, the large number of sponsors of the Green New Deal demonstrate much greater support for controlling carbon emissions than existed in 1998.

Vitol also sees geographical differences. The Vitol executive pointed to four regions: The U.S., China, EU, and California, when discussing climate change views. He pointed first to the experience

This third group has 30% of the total utility group customers, which reflects people being willing to buy renewable power, regardless of its cost

of the EU and its carbon trading scheme, which he characterized as essentially a wish list, but technically not reality. This scheme became too expensive and has been abandoned, disrupting the plans of those religiously trying to follow the scheme. On the other hand, in California there is a mechanism for electricity buyers and suppliers to form utility groups. Usually, when buying groups are formed, it is to seek economies of scale to reduce a product's price. In this case, he pointed to three utility group offerings: one offering electricity with a 30% renewable component, which is offered at a 2% discount to the regulated power price. The second offering is 50% renewables and its price is equal to the utility rate. The third offering is for 100% renewable power, and it carries a 9% price premium to the utility rate. He pointed out that this third group has 30% of the total utility group customers, which reflects people being willing to buy renewable power, regardless of its cost.

BP, while still actively expanding its oil and gas portfolio, is making a commitment to increase investments in clean energy projects

The bulk of the panel's time was devoted to discussing the technical aspects and economics of renewables, as well as the challenges of navigating a company's strategy within the broader context of a global energy transition. The BP speaker reminded the audience of BP's history with clean energy, which took off when Lord Brown was the company's CEO in the early 2000s. He directed a corporate rebranding of BP as "Beyond Petroleum," spending millions of dollars before abandoning the effort. Of course, the modern BP is most noted for the Macondo well blowout in the Gulf of Mexico and the lives lost, as well as the environmental disaster it created. The disaster cost BP billions of dollars in costs associated with the clean-up, legal expenses and penalties imposed by the U.S. government. That cost forced management changes and significant restructuring changes as substantial chunks of the company were disposed of in order to fund the payments BP had to make over the ensuing years. Now, however, BP, while still actively expanding its oil and gas portfolio, is making a commitment to increase investments in clean energy projects, as the company's strategy, under current CEO Robert Dudley, is "to reduce emissions in our operations, improve our products to help our customers reduce their emissions, and create low carbon businesses."

The challenge is knowing what to invest in

As part of this effort, BP is devoting 5%-10% of its annual capital spending budget to clean energy investments. With annual capex spending in the $15-$17 billion range, this strategy leads to potentially 100% of the annual capital spending budget being committed to the development of renewable businesses over ten years. The challenge is knowing what to invest in. There is no clear roadmap for transitioning away from fossil fuels, which will remain an important source of global energy for years into the future, and toward a completely renewables business. There is no assurance about which of the myriad of clean technologies will be successful. Thus, BP focuses on "angel investing" in new clean technologies, while diligently working to reduce its carbon footprint and producing more natural gas, as those emissions are half of crude oil's.

Renewable diesel should not be confused with biodiesel

One technology BP is focused on is renewable diesel fuel, which is refined from rendered lard and cooking oils. Renewable diesel should not be confused with biodiesel, which is also manufactured from cooking oil and other waste products. High-quality renewable diesel is also known as Hydrotreated Vegetable Oil (HVO), whereas traditional biodiesel is also referred to as Fatty Acid Methyl Ester (FAME). These two clean diesel fuels are often confused since they are refined from similar raw materials. Rather than getting into the chemistry of clean diesel fuels, we have elected to quote two explanatory paragraphs from the web site of Neste Oyj (NESTE.HE), the Finland-based refiner of renewable diesel, to explain the issue.

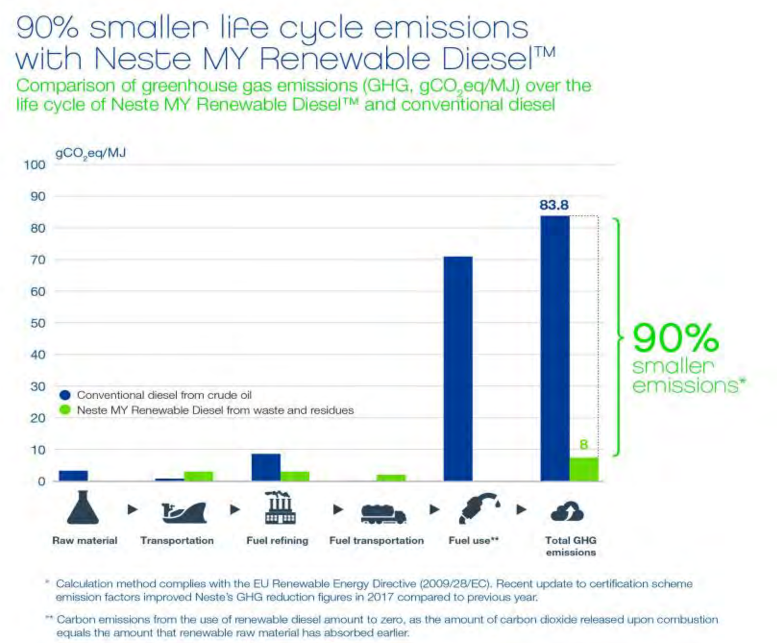
> "Premium-quality, HVO-type Neste Renewable Diesel is made primarily from waste and residues. In the production process, impurities are removed from the raw materials which are then hydrotreated at a high temperature. The outcome is a colorless and odorless fuel of an even quality that has an identical chemical composition with fossil diesel. It is also often called an 'advanced biofuel' or 'second-generation biofuel'.
>
> "Traditional, first-generation FAME-type biodiesel, on the other hand, is produced by esterifying vegetable oils or fats. The esterification process restricts the use of poor quality or impure raw materials, such as waste and residues. The quality of traditional biodiesel varies also in other respects according to the raw materials used."

The key point about renewable diesel is that its chemical properties are identical with those of petroleum diesel, allowing it to be blended with regular diesel or used as a complete substitute. The same cannot be said about biodiesel, as it has contaminants that can create operational problems with fuel lines and diesel engines. According to Neste, over the lifecycle of producing and burning renewable diesel, carbon emissions can be reduced by up to 90% (See Exhibit 1, next page).

One issue both speakers agreed on was the lack of financial returns from renewable fuel technology investments

One issue both speakers agreed on was the absence of financial returns from renewable fuel technology investments. As the Vitol presenter remarked, there are no viable returns at scale in solar or wind. As a trading company, Vitol has been presented with numerous opportunities to be the counterparty to various clean energy investments. In the case of solar, the developers often maximize the difference between the solar panel's price when the deal is signed versus when it is constructed. In other words, the financial returns have been dependent on the continued declines in solar panel costs. When panel costs stop falling, the financial returns will then have to come from the operation of the project, not its lower capital cost, meaning pricing will need to change.

Exhibit 1. Emissions Benefits Of Renewable Diesel



Source: Neste

All the return is based on speculating on what future electricity prices will be in 10 years

He later explained, when repeating his claim that the returns in renewables are not there, that solar projects Vitol has seen used to be based on 15-20 year lives with power purchase agreements (PPA) based on utility electric rates. These projects offered investors rates of return comparable to bond yields, but without the liquidity of public markets. Those returns are well below the return thresholds required for Vitol's trading businesses. Now, it is seeing 10-year PPAs at zero rates of return, with all the project's financial rewards dependent on the price curve starting 10-years in the future. In other words, all the return is based on speculating on what future electricity prices will be in 10 years. Given the history of commodity and energy fuel pricing forecasts, those projects offer little return, but contain high risk.

China has roughly 1.8 million buses, and over 400,000 have been converted to electric power, cutting diesel consumption

There was discussion about electric vehicles (EV) and batteries, which Vitol sees as an interesting development, but with limited clarity about where the investment opportunities exist. The speaker pointed out that Vitol has already seen the EV impact on China's oil market. Vitol estimates that the diesel market in China has declined by 300,000 barrels per day, as the country switches its transportation system over to electricity. China has roughly 1.8 million buses, and over 400,000 have been converted to electric power cutting diesel consumption.

A popular conclusion from many of the presentations at the Baker McKenzie conference was that the energy transition will probably

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happen slower than many of its proponents believe. This doesn't mean, however, that major oil companies are not focused on how and when to accelerate their transition efforts. Companies realize that the transition path is likely to mean a shift from oil to natural gas, and then to wind and solar, unless a new technology emerges. Preparing for those shifts will require planning, and an increased understanding of the risks to company business strategies. For example, it was pointed out how the decommissioning costs in the Gulf of Mexico shallow water oil and gas province is now a meaningful risk that must be assessed and factored into the economics of any investments in this sector. That risk may deter a recovery in the shallow waters of the Gulf until commodity prices rise further.

A major concern for energy executives is the stability of "green regulation." For example, the cap-and-trade programs that have been tried in various regions and later abandoned alter the returns from clean energy projects that have already been put in place, or are in development. This regulatory starting-and-stopping adds risk to threshold-return targets, which could preclude some clean energy investments.

Low returns represent the flip side of the high cost of developing renewable energy projects that can match the operating performance characteristics of conventional electricity generation facilities

The strong statements from various presenters about the low or nonexistent financial returns from renewable energy projects seemed to surprise some in the audience. Low returns represent the flip side of the high cost of developing renewable energy projects that can match the operating performance characteristics of conventional electricity generation facilities. This issue was explored in a recent report, "Exploding Duck Curve: What Does It Cost to Achieve 100% Renewable Electricity and What Are the Implications," authored by Hugh Wynne and Eric Selmon of the Utilities, Power Equipment & Renewable Energy sector at SSR, LLC. Their report specifically addressed the issue of the cost for meeting California's 2018 legislative target requiring 100% of California's retail electricity sales to come from zero-carbon resources by 2045. At the present time, California has a single nuclear power plant in operation, which is scheduled to close in 2025, thus setting the state on the road to 100% renewable energy to generate its electricity needs.

The objective of the modelling was to determine the least costly mix of renewable energy sources to meet California's electricity needs during every hour of the year. As they wrote, "Our model balances (i) the state's aggregate demand for electricity for each hour of 2017 (hourly load in kWh), with (ii) the output of a fleet of wind, solar, hydroelectric and geothermal resources, complemented by energy storage, and sized to ensure an adequate supply of renewable energy in each hour of the year." This methodology enabled the authors to factor into their calculations the existing contributions from California's hydroelectric and geothermal resources.

There would be periods when sufficient renewable power was not available to keep the lights on

The modelling exercise precluded any reliance on conventional power generation, such as gas turbines, which are used to back up intermittent renewable electricity supplies. The researchers also employed the actual 2017 output figures for wind and solar from typical locations in California when estimating the electricity to be generated from future renewable facilities required. What was clear from their research was that there would be periods when sufficient renewable power was not available to keep the lights on, therefore, these power gaps were filled with power drawn from battery storage.

As the amount of future wind, solar and battery storage needed to satisfy the future electricity demand exceeds California's existing capacity of these assets, the authors estimated the cost to build new facilities as well as their operating costs. The combined costs have been translated into estimates of the current levelized cost of energy (LCOE) for these resources and imputed to all the wind, solar and battery storage resources that will be needed to meet the 100% renewable target.

The battery storage resource is equivalent to 177.5 GW of power, assuming the typical four-hour duration of discharge for a lithium-ion battery

Utilizing the lowest cost mix of wind, solar and battery storage, along with the existing hydroelectric and geothermal resources, which are assumed not to grow in the future, California will need 15 gigawatts (GW) of wind capacity, 250 GW of solar capacity and 710 gigawatt-hours (GWh) of battery storage capacity. The battery storage resource is equivalent to 177.5 GW of power, assuming the typical four-hour duration of discharge for a lithium-ion battery. The projected mix of energy resources compares with the state's existing installed capacity of 9.2 GW of wind, 13.8 GW of solar and 0.2 GWh of installed battery storage. The state needs substantial investment.

The projected $160/MWh cost difference represents a 300% increase, which translates into an estimated $37 billion annual economic burden on the state

The price tag for these resources, based on their current construction costs, plus the market value of the hydroelectric and geothermal generation that will be used, is equivalent to $213 per megawatt-hour (MWh) of retail electricity supplied in California. This cost compares to an average around-the-clock price for "full requirements" electricity of $53/MWh in 2018. The projected $160/MWh cost difference represents a 300% increase, which translates into an estimated $37 billion annual economic burden on the state. ["The full requirements price of electricity is the price sufficient to pay for the resources required to supply 100% of the electricity demand prevailing during each hour of the year. It includes the cost of energy, capacity, transmission and ancillary services."]

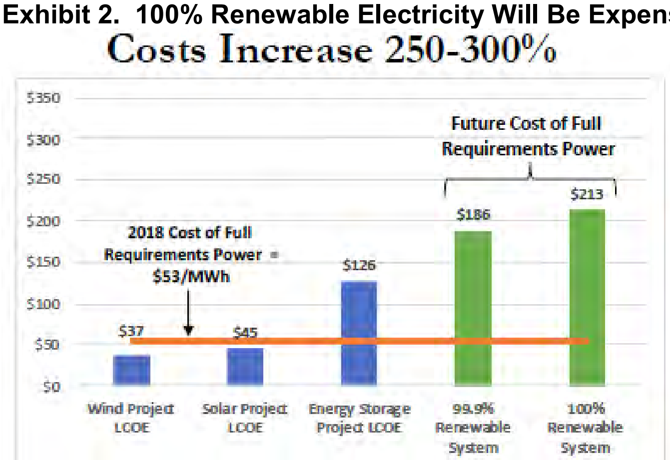
The cost to California's residents and the state's economy of this transitioning to 100% renewable power is huge. The authors acknowledged that the history of wind, solar and battery storage has been marked by reduced costs and improved energy efficiency. Therefore, they also estimated the LCOE for these resources based on estimated costs in 2025, which brings the total cost down to $147/MWh in 2019 dollars, from the current estimate of $213/MWh.

By 2030, there should be further cost and efficiency improvements bringing the LCOE cost down to $127/MWh in 2019 dollars. Compared to the 2018 full requirements electricity cost of $53/MWh, the 2030 cost will be $74/MWh greater, equivalent to a $17 billion annual burden on the California economy and its residents.

The magnitude of the cost savings by not having to achieve full renewable electricity generation highlights the high cost of renewables

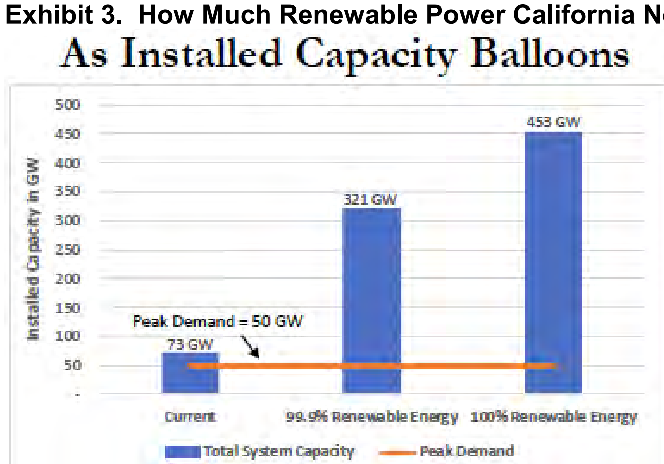
In response to the high cost of the 100% renewable target, the study's authors examined an alternative scenario. If the renewable target were reduced to only 99.9%, with the balance of the power needs coming from gas-fired generators, the total power cost could be reduced by 13%, from $213/MWh in 2019 to $186/MWh in 2045. The cost would fall by 10% from $147/MWh in 2024 to $132/MWh; and from $127/MWh in 2030 to $114/MWh, also a 10% reduction. The magnitude of the cost savings by not having to achieve full renewable electricity generation highlights the high cost of renewables.

Exhibit 2. 100% Renewable Electricity Will Be Expensive



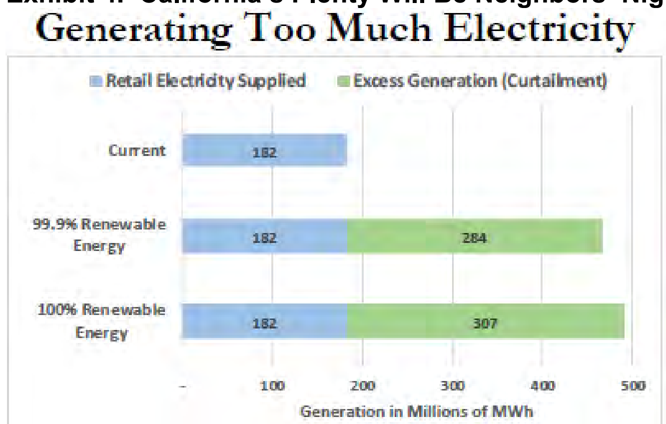
Source: SSR

Exhibit 3. How Much Renewable Power California Needs



Source: SSR

Exhibit 4. California's Plenty Will Be Neighbors' Nightmare

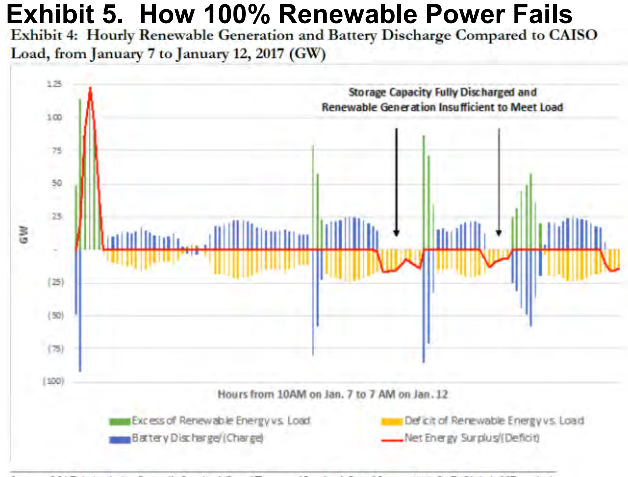


Source: SSR

That analysis reinforces the point that to compensate for these eventual gaps in 100% electricity assuredness, the power system needs to be constructed with much greater capacity

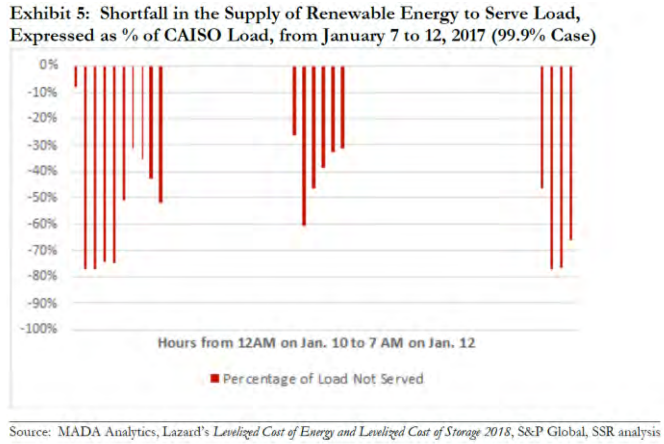
The alternative renewable resource scenario was driven by the recognition that the nature of wind and solar power, including the use of battery storage backup, would have left California without any electricity for some hours during the span of January 7, 2017 to January 12, 2017. That analysis reinforces the point that to compensate for these eventual gaps in 100% electricity assuredness, the power system needs to be constructed with much greater capacity. The SSR study concluded that during the January 2017 period, the combination of low solar generation due to reduced output from the sun in winter, combined with cloudy and rainy winter weather and windless nights caused the 99.9% capacity system to fail to deliver power for 20 hours. "During 10 of those hours, the system would have fallen short of supplying the state's electricity needs by 50% or more and, during 4 of those hours, the system would have fallen short by more than 75%," the study's authors wrote.

Exhibit 5. How 100% Renewable Power Fails



Source: SSR

Exhibit 6. Those Hours When Renewables Fail



Source: SSR

To overcome this shortfall, without relying on combined-cycle natural gas generators, would force the expansion of the state's battery storage by 48 GW and the capacity of its combined wind and solar facilities by 85 GW, resulting in an additional capital investment of $125 billion. With a 100% renewables electricity system, another challenge arises from the huge supply of surplus electricity that may be generated at points in time and needs to be shipped elsewhere. The study's authors calculated that the 100% renewable system would be capable of generating an estimated 307 million MWh of electricity in excess of the state's needs. That excess electricity is equal to 133% of California's needs and over 80% of the combined electricity consumption of the neighboring states of Washington, Oregon, Idaho, Nevada, Utah and Arizona. This creates situations where California might be pushing excess power into these neighboring states at a time when they do not need it, so they would be forced to seek other outlets for their sudden electricity surplus. Since they cannot be assured this excess California power would always be present, those states could not downsize their electricity generation capacity without running the risk of being suddenly without sufficient electricity at some point.

With a 100% renewables electricity system, another challenge arises from the huge supply of surplus electricity that may be generated at points in time and needs to be shipped elsewhere

The SSR study demonstrates the operational challenges for meeting 100% renewable electricity requirements in California, a state with favorable climate conditions and a larger existing zero-carbon resource than found in many other states in the nation. The study showed just how expensive and burdensome such a 100% renewable electricity system would be. When we consider these outcomes, given the statements from BP and Vitol about the lack of financial returns for renewables power projects at scale, we are left wondering how much more expensive these zero-carbon mandates will turn out to be once they are undertaken when developers require reasonable financial returns. The only saving grace from these politically-mandated programs is that the public will quickly see what they will cost (with little to no climate change impact), and hopefully

We are left wondering how much more expensive these zero-carbon mandates will turn out to be once they are undertaken when developers require reasonable financial returns

before existing and recently retired conventional electricity generating capacity is dismantled, enabling a detour to a different route to a cleaner power system at a lower cost.

Green Energy Support And Coal's Power Output Demise

Their analysis says that in April, renewables were on track to surpass the estimated 2,000-2,200 KMWh/d of electricity generated by coal

Smithsonian.com carried a column on May 2nd titled "For the First Time, Green Power Tops Coal Industry in Energy Production in April." We were quite surprised by the headline, as we are not aware that the government or industry is capable of producing national energy data for the prior month within two days of its ending. It turns out that the article was playing off a report by a CNN reporter who was discussing a recent analysis by the Institute for Energy Economics and Financial Analysis (IEEFA), a non-profit that supports the transition to clean energy. Their analysis says that in April, renewables were on track to surpass the estimated 2,000-2,200 thousand megawatt-hours per day (KMWh/d) of electricity generated by coal. IEEFA also said that this trend was likely to continue through May, and may occur sporadically throughout the rest of 2019 and 2020. This is good news for renewable fans and bad news for coal workers.

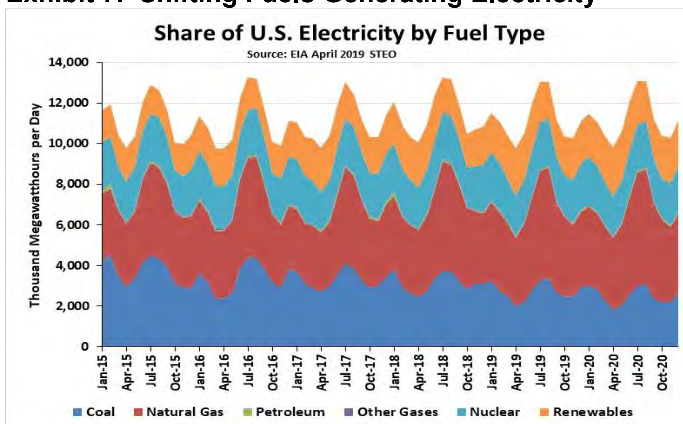
The article, which was written as a statement of fact backed up by statistics from the U.S. Energy Information Administration (EIA), actually was based on the agency's recently released forecast. Each month, the EIA prepares projections by month for a wealth of energy data series. Their forecasts extend from the latest monthly data released by the agency, in this case January 2019, through the end of 2020. One of the many tables produced shows the amount of electricity generated per day by fuel source. Sure enough, the April Short Term Energy Outlook (STEO) projects that electricity derived from renewable fuels in April totaled 2,322 KMWh/d, while that coming from coal-fired generators only reached 1,997 KMWh/d.

The April 2019 projection certainly supported the statement attributed to Dennis Wamsted, the IEEFA report author, who was quoted saying, "Five years ago this never would have been close to happening." He went on to say, "The transition that's going on in the electric sector in the United States has been phenomenal." That is certainly true, and largely reflects the efforts of politicians interested in demonstrating their embrace of the dangers from climate change, resulting in the need for clean energy fuels.

There is definitely a downward trend in the production of electricity from coal

To better appreciate the EIA's forecast, we studied both the long-term trends in electricity generated by fuel source. We plotted the monthly data from 2015, which is part of the tables in the STEO report, through the December 2020 forecast. It shows that there is definitely a downward trend in the production of electricity from coal. We also see more electricity coming from natural gas generators, as well as more from renewable fuels. In reality, there are four dominant fuel sources for electricity – coal, natural gas, nuclear power and renewables. Petroleum has been banished from the fuel slate, with the exception of its heavy use in New England during the winter when natural gas volumes are diverted to home heating at the expense of generating electricity. Only in isolated spots are other gases used to produce power.

Exhibit 7. Shifting Fuels Generating Electricity

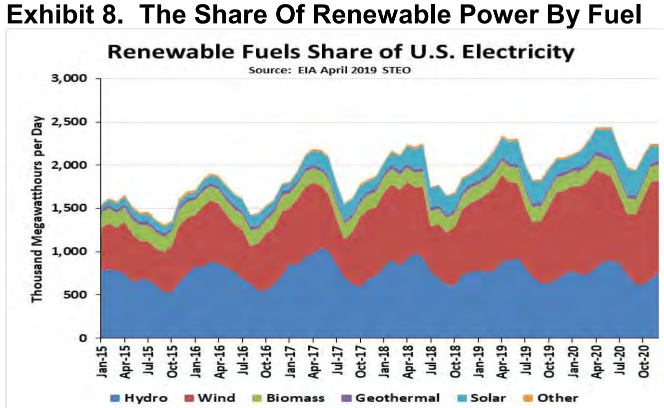


Source: EIA, PPHB

Conventional hydropower had a very steady output, something that has existed for decades

What is interesting to look at is the components of the renewables sector over the same time span. It shows how conventional hydropower had a very steady output, something that has existed for decades. The growth of hydropower depends on winter snows and year-round rain, as the United States is no longer adding to its dams, rather dismantling some for environmental reasons. The other very obvious point from the chart is the growth of wind power, which is attributed to the substantial tax subsidies for new wind farms. Biomass (wood), geothermal and other renewable fuels have demonstrated relatively stable outputs over the five-year period of data and projections. Solar power shows increasing volumes, again largely due to the heavy subsidies afforded developers, and the popularity of solar as a vehicle for distributive power.

Exhibit 8. The Share Of Renewable Power By Fuel



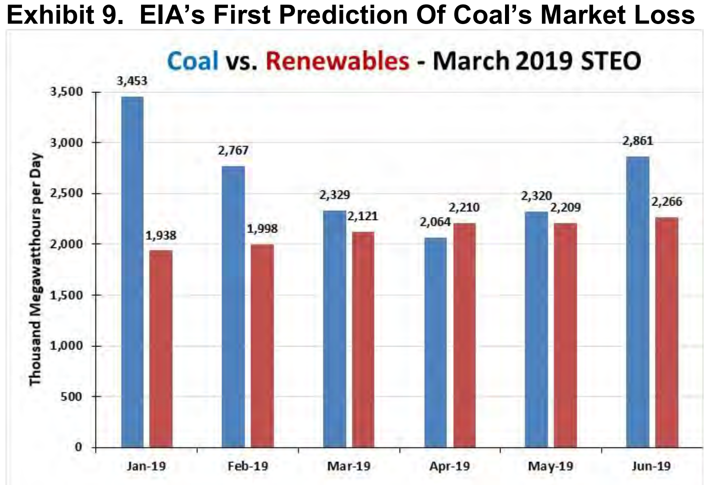
Source: EIA, PPHB

It is interesting that the report also showed renewables outperforming coal for April

The data and projections certainly appear to support the conclusions of the IEEFA analysis. That said, we went back to the March 2019 STEO and examined the same data and forecasts. It is interesting that the report also showed renewables outperforming coal for April. How come the IEEFA didn't author an analysis at that time? Of course, we still need to understand if the EIA's forecasts are actually realized, or if they might disappoint.

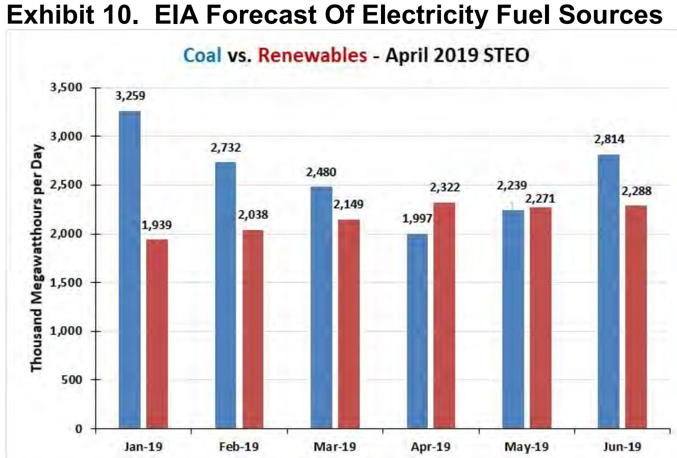
We prepared charts of the competitive positions of coal and renewables for each of the first six months of 2019 as projected by the March and April STEOs. It should be noted that the April STEO has actual January 2019 data rather than a projection, as shown in the March STEO chart.

Exhibit 9. EIA's First Prediction Of Coal's Market Loss



Source: EIA, PPHB

Exhibit 10. EIA Forecast Of Electricity Fuel Sources



Source: EIA, PPHB

What is interesting to observe is that renewables exceed coal's output in April in both the March and April STEOs. According to the

Within the renewables category, hydropower increases 3.9% and wind jumps by 12.4%

April STEO, however, renewables are projected to slightly outperform coal in the month of May, besides April. To better understand the dynamics the EIA is attempting to capture in its projections, we compared the March and April STEO forecasts for the month of April by each of the principal renewable fuels and coal. What we see is that coal's electricity output estimate falls by 3.2% between the two forecasts, while total renewables increases 5%. Within the renewables category, hydropower increases 3.9% and wind jumps by 12.4%, although solar declines by 10.1%. The remaining renewable fuel categories decline, but only marginally.

Exhibit 11. How STEO Forecasts Changed

April 2019 Projection (MWh/d) ..	March STEO	April STEO	Difference
Conventional Hydropower	850	883	33
Wind	897	1,008	112
Wood Biomass	113	107	-5
Other Waste Biomass	57	57	-1
Geothermal	46	45	-1
Solar	247	222	-24
Coal	2,064	1,997	-67

Source: EIA, PPHB

The major renewable fuel gain was produced by conventional hydropower, which generated 9% more electricity than forecast

While not meaning to criticize the EIA, forecasts are basically highly-educated guesses based on studying past trends and assimilating current information and motivations to arrive at a number. If we examine the January 2019 actual data compared to the last forecast, we see that both coal and renewables outperformed their projections. In this case, renewables electricity was 4.7% greater than forecast in March 2019. At the same time, however, coal's electricity output was 11.1% greater than projected. There is no doubt that January 2019 was colder due to several polar vortex events that drove temperatures down to extreme lows in the Midwest and Northeast forcing increased reliance on electric heat. Those weather events also impacted wind's output, which dropped sharply due to still days and nights associated with the bitter cold temperatures. Interestingly, the actual wind energy output was higher than the EIA was predicting, but only by 1.5%. The major renewable fuel gain was produced by conventional hydropower, which generated 9% more electricity than forecast. The point of this analysis is to remind people that forecasts or projections are merely estimates and they often can be wrong. The problem is no one knows whether the estimates may prove too high or too low.

"As natural gas achieved earlier, renewable generation is catching up to coal, and faster than forecast"

Mr. Wamsted was quoted in the *Smithsonian.com* column making the point about why coal proponents should not be dismissive of these statistics. He wrote: "…we believe they are indicative of the fundamental disruption happening across the electric generation sector." Mr. Wamsted further observed that "[a]s natural gas achieved earlier, renewable generation is catching up to coal, and faster than forecast." We would point out, however, that natural gas gained its market share based on competitive market dynamics – lower prices, a better emissions profile and solid operating statistics - and not due to financial subsidies and political mandates.

Shale 2.0, Global Oil Markets And O&G Business Models

Global oil supplies are being restrained by continued political turmoil in Libya, Venezuela and Nigeria

World and U.S. crude oil prices seem to be in a pause following their dramatic recovery from the collapse during the fourth quarter of 2018. Since West Texas Intermediate (WTI) reached its low price on Christmas Eve 2018, the price rebounded 50% through the end of April. The final week of April saw the price rise retreat by 6%, and WTI has remained volatile in the early days of May. This recent price action reflects crosscurrents buffeting the drivers of oil demand and supply. Concern over global economic weakness sapping the strength in demand growth has been offset by the reaffirmation of OPEC and Russia to abide by their combined 1.4 million barrels per day output cut. Global oil supplies are being restrained by continued political turmoil in Libya, Venezuela and Nigeria. Were it not for the continued rapid growth in U.S. oil production, and its blossoming oil exports, global oil prices would likely be higher, especially when one considers the uncertainty over future Iranian oil exports generated by the upcoming expiration of waivers from financial sanctions granted to certain U.S. allies who buy that nation's oil.

Today, barely three years later, the U.S. oil industry is shipping two million barrels a day of its oil to international customers

Much like how the explosion of new oil supplies from the North Sea, Brazil and West Africa destroyed the global oil market's paradigm in the 1980s, shale and tight oil in the U.S. is playing the same role today. If we were to review the strategic business plans of international oil companies (IOC) from five years ago, and certainly from 10 years ago, we would likely not find predictions of the United States exporting its crude oil output. The idea that the U.S. government would overthrow its historical (since the 1973 oil embargo) legal restriction against exporting domestic crude oil output, let alone overcome the physical limitations imposed by three decades of falling production, was not considered feasible. Two years of lobbying, growing oil production and a tax-and-spending bill desired by the Obama administration provided the vehicle for the impossible to occur. Today, barely three years later, the U.S. oil industry is shipping two million barrels a day of its oil to international customers. This seismic shift in the U.S. oil business is a direct result of the American shale revolution. What is only now beginning to be appreciated in economic and political circles is how this shale revolution is disrupting global oil markets, petroleum company strategic business plans and international geopolitics.

The dramatic growth in shale oil has catapulted the United States into first place among world oil producers. Given that newly acquired status, the U.S. has greater leverage in world energy markets, as it remains less susceptible to pressure from international oil producers to support their actions in return for assured oil supplies, even though the U.S. refining industry needs certain oil

Exhibit 12. How The U.S. Became World's #1 Producer

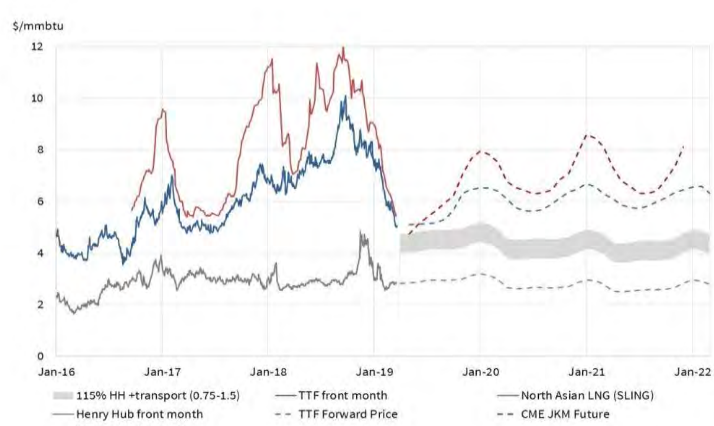
Source: EIA

types from others to maximize its output. The U.S. is using its newly achieved political independence to inflict economic pressure on adversaries such as Iran for its continued support of global terrorist organizations. Without its huge domestic oil and gas output, the U.S. would have less geopolitical leverage.

Rather than continue on its path to greater gas use in the form of LNG imports, the rising supply of domestic gas provided the U.S. with the ability to transition into a new role – a growing supplier of LNG exports

One area where American shale output has been most disruptive is in oil and gas pricing. The initial rise in U.S. shale was felt in the global gas market. Rather than continue on its path to greater gas use in the form of LNG imports, the rising supply of domestic gas provided the U.S. with the ability to transition into a new role – a growing supplier of LNG exports. Removing a projected huge consumer of global LNG, and transitioning it into a significant LNG supplier has caused significant shifts in global LNG flows with ramifications on global gas pricing. A mild winter in Asia has also contributed to dramatic weakness in LNG prices in that geographic region. The global LNG market is increasingly becoming a spot market with LNG prices becoming disconnected from oil-price indexes, thereby reducing Asian energy import costs and helping revive various countries' economies.

Exhibit 13. How U.S. Gas Impacts Asian LNG Prices

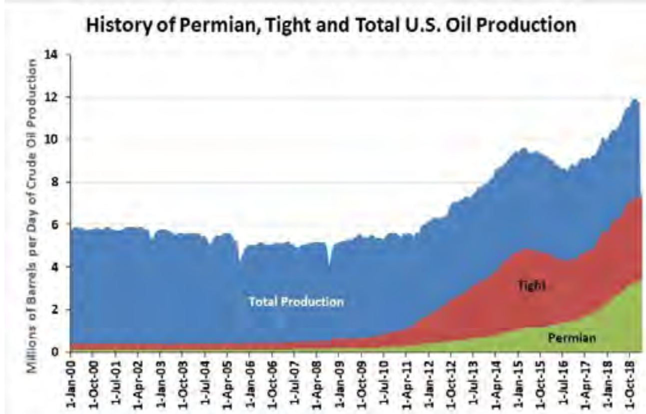


Source: *oilprice.com*

It has been almost totally due to shale's output growth

The impact of the shale revolution on U.S. crude oil markets has been nothing short of dramatic. One sees how U.S. domestic oil output has soared in recent years. It has been almost totally due to shale's output growth, as represented by the tight oil area noted in Exhibit 14. In turn, growth in Permian Basin tight oil output has been responsible for a significant share of total tight oil supply growth.

Exhibit 14. How Permian Oil Is Driving U.S. Oil Growth

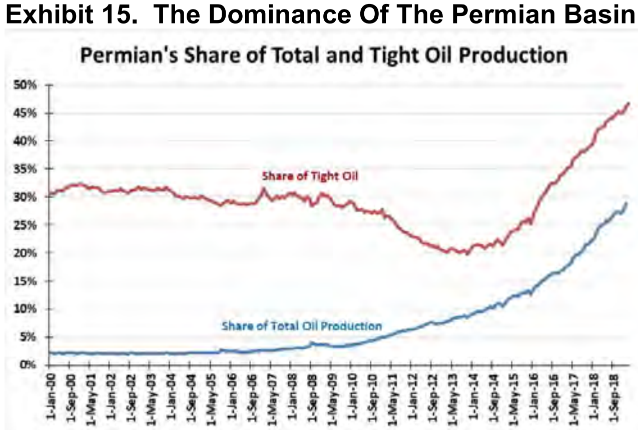


Source: EIA, PPHB

As of January 2019, Permian shale oil represented 45% of total tight oil output, but notably nearly 30% of all U.S. oil production

To gain a greater appreciation for the Permian Basin's contribution to the American shale revolution, one only needs to see its contribution to total oil production and total tight oil output since the start of this century. Exhibit 15 shows the respective shares of the two oil categories represented by Permian output. As of January 2019, Permian shale oil represented 45% of total tight oil output, but notably nearly 30% of all U.S. oil production. It is also noteworthy that the explosion in Permian tight oil output has occurred in the past eight years. The decline in the Permian's contribution to total tight oil output experienced during 2010-2016 was due to the explosive growth in output from the Bakken and Eagle Ford formations, and before that explosive growth moved to the Permian.

Exhibit 15. The Dominance Of The Permian Basin



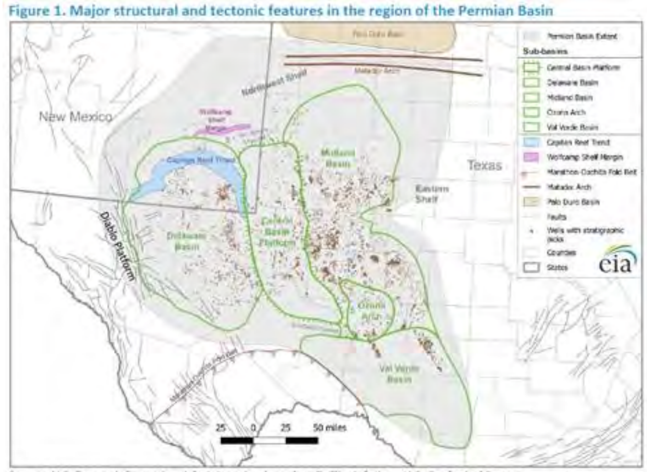
Source: EIA, PPHB

According to the EIA as of September 2018, the basin has supplied more than 33.4 billion barrels of crude oil and 118 trillion cubic feet of natural gas

The Permian Basin of West Texas and Southeast New Mexico covers an area of more than 75,000 square miles, extending across 52 counties in West Texas and Southeast New Mexico. It has produced hydrocarbons for about 100 years. According to the EIA as of September 2018, the basin has supplied more than 33.4 billion barrels of crude oil and 118 trillion cubic feet of natural gas. The use of hydraulic fracturing, horizontal drilling and modern completion technology has revived the basin and lifted its output well beyond the basin's previous production peak in the early 1970s.

Exhibit 16. The Most Important U.S. Shale Basin

Figure 1. Major structural and tectonic features in the region of the Permian Basin



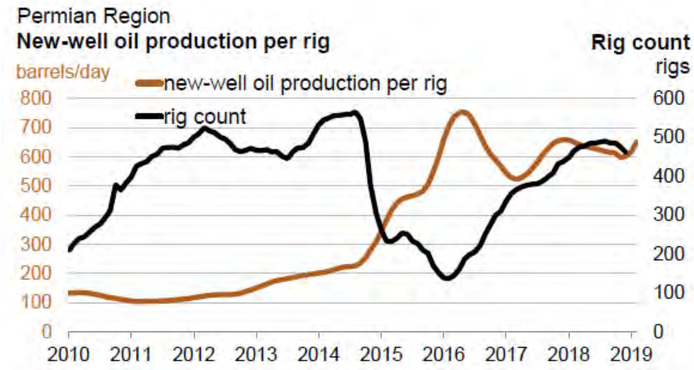
Source: U.S. Energy Information Administration based on DrillingInfo Inc., U.S. Geological Survey.

Source: EIA

The basin accounts for 46.4% of all the active U.S. drilling rigs

The Permian Basin must be considered the premier hydrocarbon basin in the United States today, accounting for 29% of the nation's oil output and 9% of its natural gas production, and it remains the most active basin for drilling and well completions. As of May 3rd, there were 459 drilling rigs operating in the Permian, all targeting crude oil. The basin accounts for 46.4% of all the active U.S. drilling rigs. Since early 2011, the total active Permian rig count has risen 21.4%, with the number of rigs targeting crude oil climbing from 357 to 459, for an increase of 28.6%. Despite the oil price recovery since December 2018, the lack of adequate oil and gas pipeline capacity to deliver incremental supply to market has forced curtailments in drilling. Since mid-November 2018, the combination of a lack of export pipeline capacity and sharply lower oil prices has caused the Permian active rig count to decline 7%.

Exhibit 17. EIA Sees More Permian Basin Output Growth

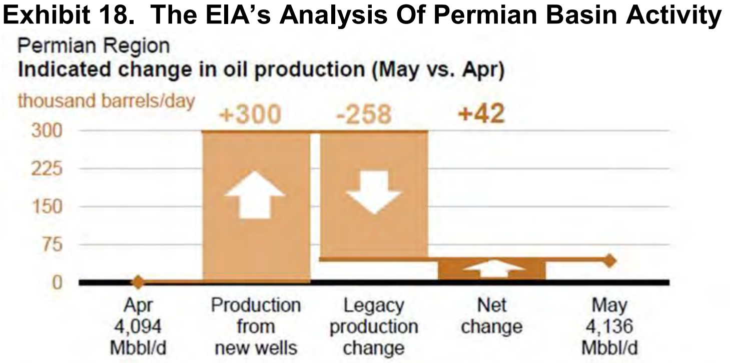


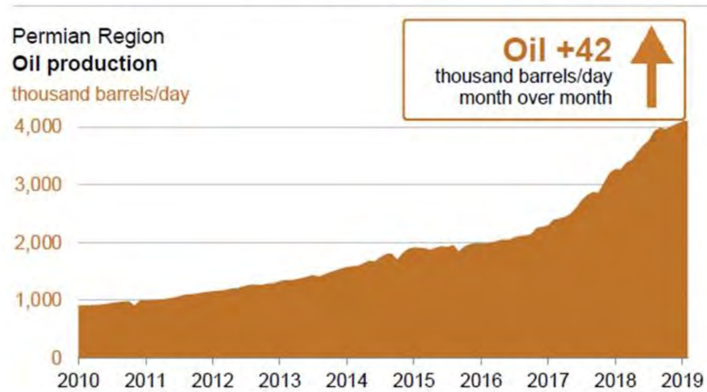
Source: EIA

Growth in oil output in the face of pipeline take-away constraints and a declining oil rig count speaks to the dynamics of this aged field, given the application of new drilling technologies

Despite the decline in the rig count, Permian oil output is expected to increase in May based on the EIA's Drilling Productivity Report. That report shows that total new oil production should be 300,000 barrels per day (b/d), which will more than offset the estimated 258,000 b/d decline in legacy oil output, netting 42,000 b/d of incremental oil supply. Growth in oil output in the face of pipeline take-away constraints and a declining oil rig count speaks to the dynamics of this aged field, given the application of new drilling technologies.

Exhibit 18. The EIA's Analysis Of Permian Basin Activity



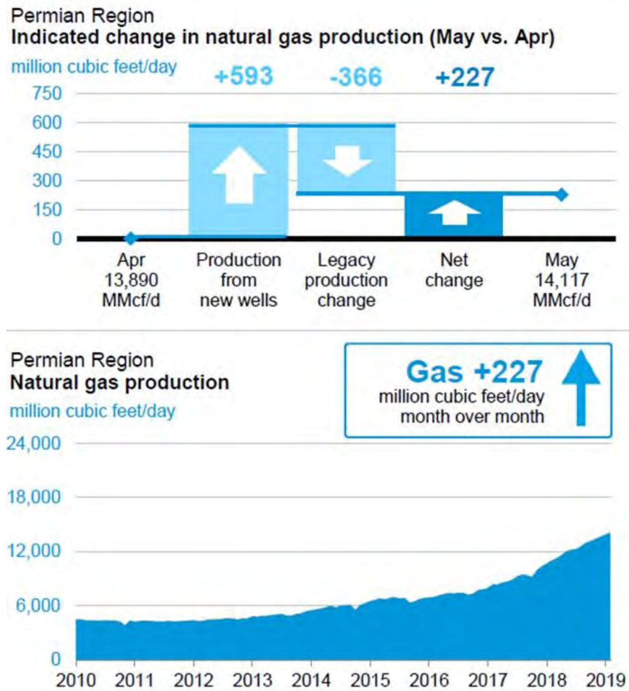


Source: EIA

With the exception of a few weeks in June 2018, the basin has not witnessed drilling targeting natural gas since the early months of 2016

The Permian Basin is demonstrating similar production dynamics for its associated natural gas output. With the exception of a few weeks in June 2018, the basin has not witnessed drilling targeting natural gas since the early months of 2016. This has not prevented the basin from continuing to grow its gas output produced in association with crude oil production. The volume of associated gas production has become so large relative to constrained pipeline capacity that producers have been forced to flare output that cannot be shipped from the basin.

Exhibit 19. Permian Basin Natural Gas Dynamics



Source: EIA

That price collapse destroyed the economics of shale gas development, forcing producers who were heavily indebted to private equity and public debt investors to seek another venue

The dynamism of the Permian is the focal point of the latest development in the American shale revolution. While some industry participants describe this evolution by noting stages of activity, we tend to mark it by shifts in the commodity focus and producer activity. For some, the shale revolution, or Shale 1.0 began two decades ago with the initial efforts of Mitchell Energy and its drilling of the Barnett Shale in the Ft. Worth Basin of Texas. That success set off a drilling boom in that region, which gradually spread to other gas-oriented basins such as the Haynesville, the Marcellus, Utica, and eventually the Eagle Ford in South Texas. Those extensions of the shale revolution coincided with the collapse in domestic gas prices from double-digit levels to the $2 per thousand cubic feet (Mcf) level. That price collapse destroyed the economics of shale gas development, forcing producers who were heavily indebted to private equity and public debt investors to seek another venue for this promising oilfield technology. Producers began applying horizontal drilling and hydraulic fracturing to crude oil basins. That effort, which accelerated in the years immediately following the 2009 recession, was supported by triple-digit oil prices. Some people call the shift from gas to oil as Shale 2.0.

Shale 1.0 was the E&P land grab from 2007 through 2011; Shale 2.0 was the productivity phase that extended from 2012 through 2016; and Shale 3.0 is the current efficiency phase in which producers maximize well output through the application of data analytics and improved logistics, procurement and commodity marketing

Will VanLoh, the founder and CEO of private equity provider Quantum Energy Partners, has described the stages of the shale revolution in the following manner: Shale 1.0 was the E&P land grab from 2007 through 2011; Shale 2.0 was the productivity phase that extended from 2012 through 2016; and Shale 3.0 is the current efficiency phase in which producers maximize well output through the application of data analytics and improved logistics, procurement and commodity marketing. This progression is similar to the historical approach to the exploration and production business. One starts by identifying a prospect, securing the land, and refining the dimensions of the target. The producer then drills the prospect and works to complete the well in the most financially-maximizing manner. From that point forward, the well/field is produced until it is depleted, and eventually plugged and abandoned.

We prefer to identify the stages of the shale revolution as Shale 1.0 being the purview of the independents – the modern version of the wildcatters who built the domestic oil and gas industry. Independents come in a wide array of companies – small, startup operations to larger, established producers who had built their companies by focusing on conventional oil and gas operations over the years. This first phase resulted in the exploration of many basins around the country, with the result that more marginal ones were deemphasized as commodity prices, well reserves and output, as well as high drilling and completion costs, made them uneconomic. Some independents were successful as they were fortunate to have leased basin sweet spots, but the burden of growth and financial leverage forced producers to switch to more promising prospects when initial efforts were unsuccessful elsewhere.

Their efforts kicked off what we describe as Shale 2.0

International IOCs were the initial large, diversified petroleum companies to jump into the shale plays. Their efforts kicked off what we describe as Shale 2.0. This phase of the shale revolution has matured with the arrival of the largest of the IOCs – Chevron Corp. (CVX-NYSE) and Exxon Mobil Corp. (XOM-NYSE). These companies are bringing some key attributes for the long-term development of shale resources – financial strength, technical expertise, data analytics, logistical expertise, transportation and refining expertise, and the proper mindset for long-term project development.

The latter quality may be the most important. Chevron and ExxonMobil are the epitome of managements that take the long-term approach to their businesses and its assets. This long-term approach is willing to accept limited or no returns on projects for an

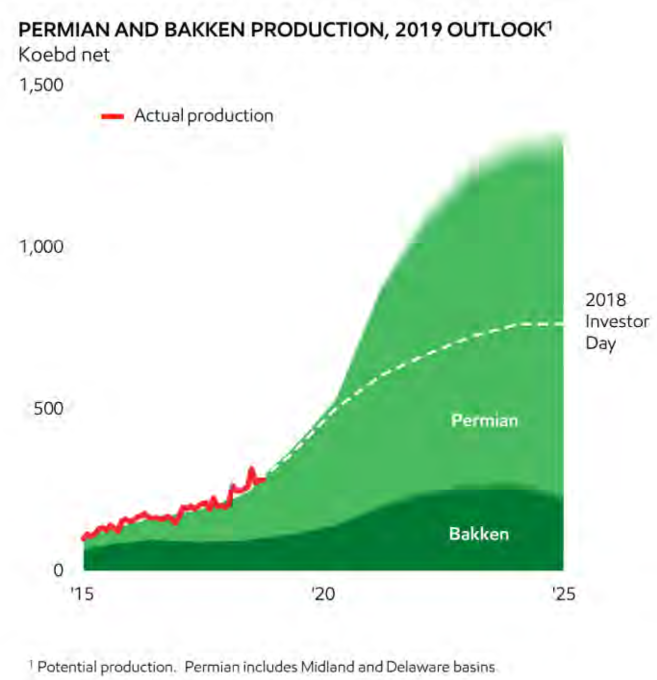
It is a total systems approach

extended period of time, as long as they remain convinced about large payoffs later. We see this mindset with respect to their international and offshore ventures, where cash and effort must be expended for years before payoffs arrive. This is how they are now approaching Shale 2.0. It is a total systems approach – establish commanding acreage positions, bring all the technological expertise company-wide to the challenges of drilling, completing and producing wells, and finally understanding how to maximize the profit from the produced oil and gas.

Each company showed its current production outlook compared to prior output guidance

At their respective analyst day presentations, Chevron and ExxonMobil set out charts showing their expectations for the future production from their Permian Basin ventures. More importantly, each company showed its current production outlook compared to prior output guidance presented at earlier analyst meetings. ExxonMobil's projected production increase is the most dramatic of the two companies. Chevron's chart presented its earlier forecasts from three analyst meetings.

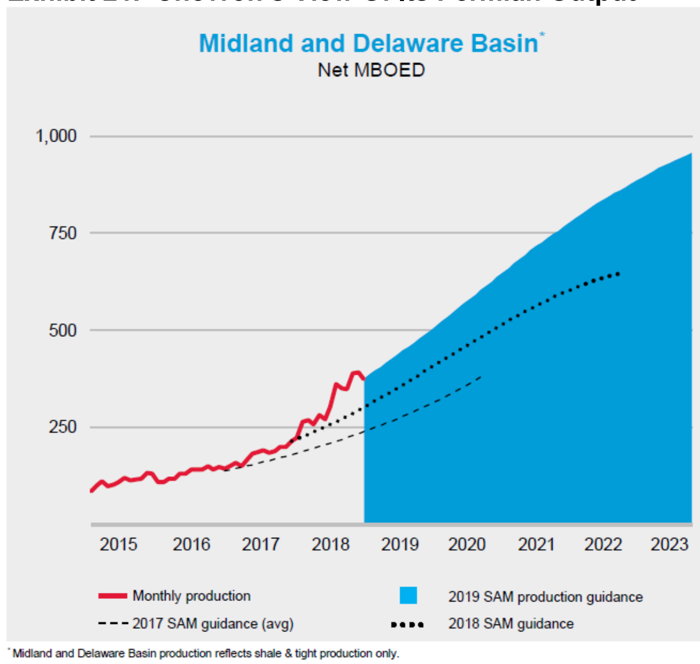
Exhibit 20. Exxon's View Of Its Permian Production



Source: ExxonMobil

While the Chevron presentation included production type-curves for its Permian wells that demonstrated improvements every year since 2016, ExxonMobil's presentation did not contain such data. What ExxonMobil did do was present detailed development plans for a number of its Permian Basin projects, showing well locations and its approach to how it planned to maximize the earnings and value of these assets.

Exhibit 21. Chevron's View Of Its Permian Output



Source: Chevron

Scale is what is important, and the IOCs are showing how critical it is for success in driving costs down and output up

One of the key requirements for successful development of shale resources is assembling contiguous acreage tracts enabling the drilling of longer lateral wells with more frac stages. This requirement has been reshaping the acreage ownerships within every large shale basin. It is what has been driving the merger and acquisition activity among shale producers, and in lease acreage purchases. These trends will likely dominate the next several years among domestic oil and gas producers as large contiguous acreage spreads are what is needed to maximize profitability. Scale is what is important, and the IOCs are showing how critical it is for success in driving costs down and output up, especially in a world where oil prices may not ever return to triple-digits, and are likely to experience further downside events. Striving to be the low-cost producer will prove critical to shale's success.

ExxonMobil and Chevron are leveraging their downstream assets and skills in order to maximize upstream shale returns

The final ingredient in Shale 2.0 that will have a lasting impact on its economics is figuring out how to maximize the profitability of well output. Rather than being only a price-taker by merely selling the well's oil and gas output at market prices, ExxonMobil and Chevron are leveraging their downstream assets and skills in order to maximize upstream shale returns. ExxonMobil's commitment to spend billions of dollars in expansions of its Gulf Coast refineries and chemical plants, as well as pipeline facilities to move its growing Permian Basin crude oil production, is an example of the company's belief in the long-term sustainability of its production, and recognition of how it can maximize profitability. These steps will also enable ExxonMobil to handle the increased light oil that is coming from its

Permian wells. The company is rumored to still be interested in acquiring additional Permian assets to further build its acreage position.

We would not be surprised to see Chevron announce an upgrade and expansion of the refinery

Chevron has agreed to acquire an idled Gulf Coast refinery from Brazil's Petrobras (PBR-NYSE) to help it handle the increasing light oil volumes coming from its Permian acreage. Once the purchase is complete, we would not be surprised to see Chevron announce an upgrade and expansion of the refinery. Its action, like that of ExxonMobil, is a statement about Chevron's commitment to, and belief in, the future of its Permian Basin shale resource.

At the start of 2017, Chevron was operating six drilling rigs. Now it has 20 operating rigs. ExxonMobil, on the other hand, has significantly ramped up its Permian activity. In 2017, it operated nine rigs, while today it has 42 rigs working across the basin, with only five not being horizontal drilling rigs.

For Occidental to take on, and apparently win, the Anadarko acquisition battle is a reflection of its need to increase its scale to leverage its already substantial Permian Basin position

The latest demonstration of the recognition of the importance of scale to be a low-cost producer in shale and the Permian Basin is the battle between Chevron and Occidental Petroleum Corp. (OXY-NYSE) over acquiring Anadarko Petroleum Corp. (APC-NYSE). One of the major attractions of Anadarko is its large acreage spread in the Permian Basin, as well as offshore and African gas assets. For Occidental to take on, and apparently win, the Anadarko acquisition battle is a reflection of its need to increase its scale to leverage its already substantial Permian Basin position. This corporate struggle is showcasing the importance the Permian and shale is playing in the thinking and strategies of IOCs and large independents striving to join that club.

Will they be seeking big oil and gas reserves and well flow rates, but without investment returns for upwards of 5-10 years, or quick production and cash returns from shale?

Whether the current state of the Permian Basin is Shale 2.0 or 3.0 is not the point of this discussion. The importance is to understand that the commitment of all the resources and technical expertise of the IOCs will impact the global oil market, as well as the domestic market. For the IOCs, they will be positioned to constantly weigh the attractiveness of short-term versus long-term investments. They will be deciding how much of their capital to devote to long-term international and offshore ventures versus their short-term shale resources. Will they be seeking big oil and gas reserves and well flow rates, but without investment returns for upwards of 5-10 years, or quick production and cash returns from shale? That strategic flexibility will enable them to better navigate the industry's future cycles – and there will be future cycles. We are looking at the ultimate commoditization of the domestic oil business. Shale scale will help boost profits if oil prices remain elevated, but, more importantly, it provides insurance against major oil price drops. Other producers, as well as oilfield service companies, need to factor the evolving shale strategies of the large IOCs into their business planning.

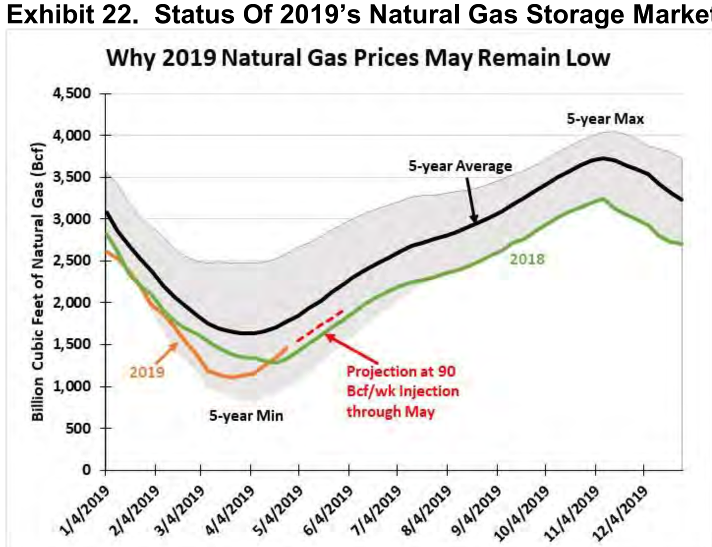
The Boring Natural Gas Market Remains Boring

With an additional two weeks of natural gas storage injection data, prices continue to reflect a market showing no concern about its ability to meet all supply demands while still building storage for next winter's heating needs. The gas storage injections for the weeks ending April 19 and April 26 were 92 billion cubic feet (Bcf) and 123 Bcf, respectively. Notably, the comparable mid-April week last year showed a continuing draw of 18 Bcf from storage, although the following week swung to an injection of 62 Bcf.

That price was viewed as a significant support level, as gas prices have only fallen below $2.50 four times during the past 20 years

Natural gas futures prices dropped below $2.50 per thousand cubic feet (Mcf) of gas as the April 26 injection data was reported. That price was viewed as a significant support level, as gas prices have only fallen below $2.50 four times during the past 20 years. Their sojourn below that threshold level proved brief, as the market shifted its focus to another blast of winter weather in the west along with concern over gas production not rising as quickly as in previous months.

Exhibit 22. Status Of 2019's Natural Gas Storage Market



Source: EIA, PPHB

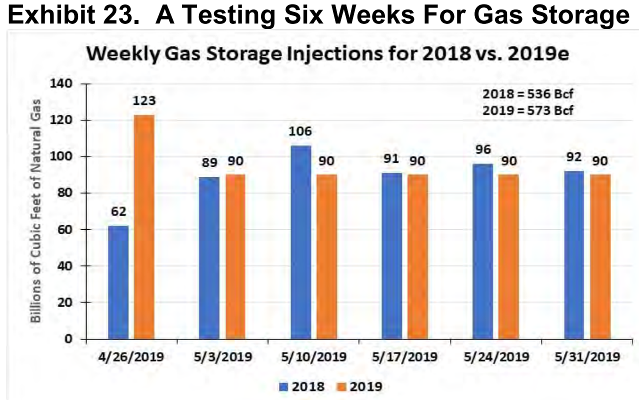
Gas traders are shifting their attention to the weather, gas export volumes and production growth

Given the magnitude of these two weekly injection volumes, natural gas storage as of April 26 stood at 82% of the 5-year average and 110% of 2018's volume. With 2019's gas storage having turned up sharply over the past few weeks, and is now healthily above last year's level, gas traders are shifting their attention to the weather, gas export volumes and production growth. Until additional takeaway capacity opens for the Permian Basin, crude oil output growth is limited, and, in turn, so is the production of associated natural gas. Additionally, if temperatures in May remain moderate in keeping with typical shoulder-month seasonal pattern, the gas

It is likely the market's focus will turn to trying to understand what will make traders worry that higher prices will be needed to boost future storage volumes

market will have sufficient capacity to rapidly build storage volumes. In 2018, for the weeks of April 27 through June 1 (six weeks), a total of 536 Bcf of gas was put into storage. Given the huge injection for this year's April 26 week, and assuming 90 Bcf per week injections for the remaining five weeks, the industry will stuff 573 Bcf into storage, a 7% increase over last year. Exhibit 23 shows how our projected weekly injections would stack up against the 2018 weekly totals. If the May 3 weekly injection reaches 115 Bcf [actually was 123 Bcf], with gas prices around $2.50/Mcf, it is likely the market's focus will turn to trying to understand what will make traders worry that higher prices will be needed to boost future storage volumes.

Exhibit 23. A Testing Six Weeks For Gas Storage

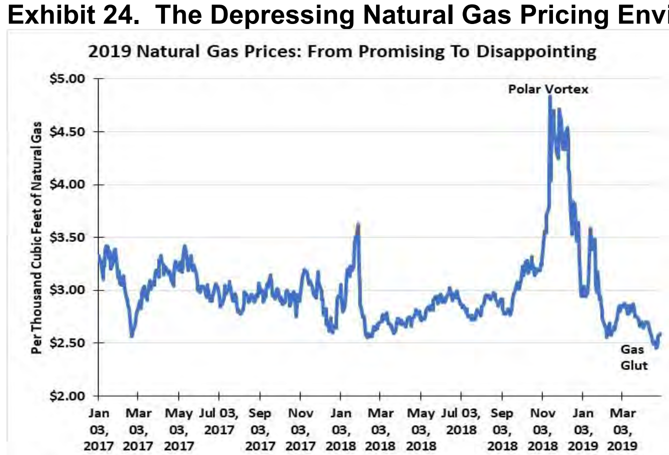


Source: EIA, PPHB

As of last Monday, the 12-month future strip for natural gas prices averaged $2.70/Mcf, while the 18-month strip was at $2.66/Mcf

A 115 Bcf injection would represent 25 Bcf more than our current projection, and 26 Bcf above 2018's volume. That could put more downward pressure on gas prices. As of last Monday, the 12-month future strip for natural gas prices averaged $2.70/Mcf, while the 18-month strip was at $2.66/Mcf. As these price projections include the seasonally-high winter prices for 2019-2020, the strip prices reflect a very muted future for natural gas prices.

Exhibit 24. The Depressing Natural Gas Pricing Environment



Source: EIA, PPHB

If commoditization is reality, producers and their service company suppliers must consider how to further reduce production costs

Absent extreme temperature events during the balance of 2019, one wonders whether we are experiencing a true commoditization of natural gas. The same question can be asked about the oil market, but we will reserve discussing that for another time. If commoditization is reality, producers and their service company suppliers must consider how to further reduce production costs. For producers, the nagging fear is that the double-digit natural gas prices of the early years of this century were the true aberration in the history of the industry, and "lower for longer" is more than an expression.

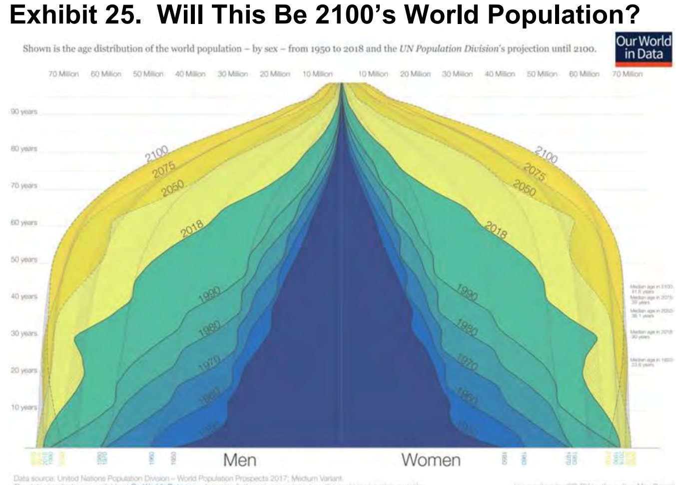
Shifting Demographics A Challenge For Future Energy Demand

One trend that is emerging is the rapid aging of the globe's population, which carries meaningful implications for future energy needs

Demographics is the statistical data relating to populations. That data is important, as it affords planners the ability to see forces that will shape long-term energy market development. Detailed demographic analysis opens windows on regional development trends and how they may impact sources of energy utilized to sustain societies and economies. One trend that is emerging is the rapid aging of the globe's population, which carries meaningful implications for future energy needs. We are beginning to examine this topic in greater depth. We hope this effort will enable us to opine on regional and age-related trends that are impacting our global demographics and how they may impact overall energy needs, along with the needs within various countries and regions.

What Exhibit 25 shows us is how the global population is projected to increase, but importantly it demonstrates the age categories that will experience the maximum sustained growth. Understanding how energy use changes as people age will become more important in the future, especially as we consider the energy transition and the relative ease or difficulty in altering particular energy supplies.

Exhibit 25. Will This Be 2100's World Population?



Source: ***Statistica.com***

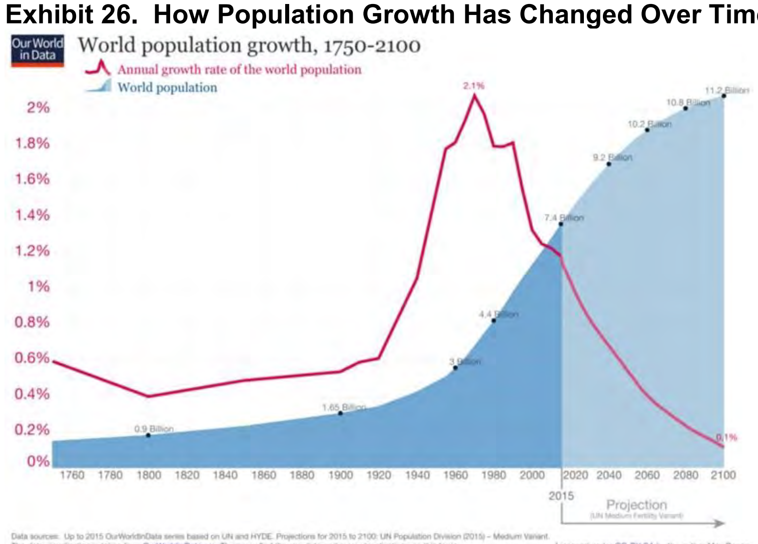
A report in Viewpoints, a 2018 publication of the investment firm Kohlberg Kravis Roberts & Co., L.P. (KKR), examined the question: "What Does Population Aging Mean for Growth and Investments?" The authors, Paula Roberts and Ken Mehlman, addressed the impact of demographic shifts on the economy and investments. They set the stage for their report with the following quotation:

> "Per the United Nations, population aging – the increasing share of older individuals in the population – is one of the most significant social transformations of the twenty-first century. At a high level, we expect global population aging to result in slower economic growth, lower financial returns, lower interest rates, increased urbanization as well as shifts in consumption and housing patterns. Each of these will have important investment implications."

There remain many subtle issues within the projected population changes that need to be better understood, and when future energy needs may be impacted

To appreciate the significance of this statement, one only needs to consider how the world's population by sex has grown and is projected to grow between 1950 and 2100. These projections come from the United Nations Population Division and shape global governance policies set forth by that world organization. The chart reflecting how the world's population has grown, and is projected to grow, dominates the visual. There remain many subtle issues within the projected population changes that need to be better understood, and when future energy needs may be impacted.

Exhibit 26. How Population Growth Has Changed Over Time



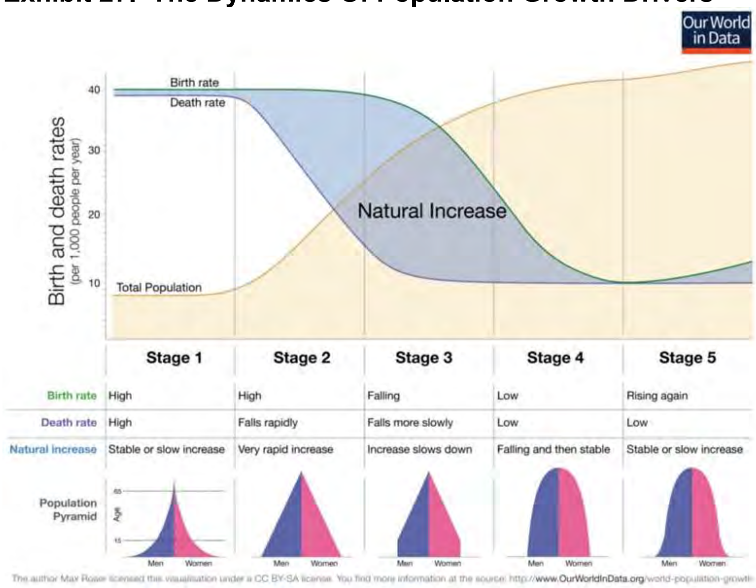
Source: ***Statistica.com***

A longer perspective of population growth, and how it is changing, is shown in Exhibit 26. With female fertility rates (births per thousand females) falling across the globe, questions about the estimates of just how large our planet's population will be in the future are being

If the world's population does not grow to the size projected by futurists, there will be implications for food and fuel

raised. If the world's population does not grow to the size projected by futurists, there will be implications for food and fuel needs, which in turn will alter projections about climate change driven by the associated carbon emissions forecasts. This is not a simple relationship, but it needs increased study to better understand the subtleties and their possible impacts.

Exhibit 27. The Dynamics Of Population Growth Drivers



Source: ***Statistica.com***

An ever-declining death rate has implications for an aging global population and the resource demands this population segment will consume

Exhibit 27 demonstrates the impact of falling death rates on population growth and aging. This is a little discussed issue, other than when the debate focuses on the quality of health care systems across the globe. However, an ever-declining death rate has implications for an aging global population and the resource demands this population segment will consume. There was a time when people living to 100 years old or longer was a rarity. Today, this age category is acknowledged and is growing rapidly due to improvements in diets and health care. Will these oldsters all be riding around in autonomous vehicles, or maybe even driving themselves, or will they largely remain homebodies? The answer to that question has meaning for future energy needs.

We are not about to present a definitive view of the global population outlook and the world's future energy demand. We know from our preliminary work on these topics is that it needs to be divided into bit-sized pieces to facilitate deeper understanding and examination of the issues. We will be focusing on some of these topics in future *Musings* reports. Therefore, we wanted to introduce this topic, helped by some interesting visual presentations of the data and drivers. We look forward to guiding readers in the quest for a better understanding of the world we will be living in and its energy needs.

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