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ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

November 3, 2020

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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

Summary:

Does Permian M&A Signal End Of This Cycle's Down Leg?

Three mergers of Permian Basin producers may be signaling the beginning of the consolidation wave everyone has been anticipating. We review Restructuring 1.0 during 1998-2002 and how the recent mergers compare.

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A Downside To Wind Turbines – Scrapping Them Safely

Decommissioning wind farms is suddenly a big business, or environmental headache. Turbine blades made from fiberglass can only be cut up and buried in landfills. Wyoming is doing it for abandoned wind farms there.

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Random Energy Observations Worthy Of Attention

Two charts of note. One highlights that per capita transportation cost has been stable since 1974! The other shows electricity cost by energy source in California versus the average of Texas, Oklahoma and Kansas.

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Does Permian M&A Signal End Of This Cycle's Down Leg?

In the span of less than a month, three significant mergers

Wow! In the span of less than a month, three significant mergers involving exploration and production (E&P) companies operating in the Permian Basin were announced. These deals follow the July merger announcement involving Chevron Corporation and Noble Energy. That deal, while having a significant component of value attributed to Noble Energy's Permian Basin acreage, also brought attractive international exploration and production opportunities that further boost Chevron's global operating scale.

The three recent Permian-centric deals included Devon Energy Corporation and WPX Energy Inc., ConocoPhillips and Concho Resources Inc., and Pioneer Natural Resources Company and Parsley Energy Inc. The last two deals were announced literally within hours of each other, in what seemed to many observers to be a rush to complete deals before all the attractive candidates were taken off the draft board.

The four significant E&P mergers this year reinforce the argument that the oil industry's road to salvation desperately requires consolidation

The four significant E&P mergers this year reinforce the argument that the oil industry's road to salvation desperately requires consolidation. That would be the best and quickest way to return the industry to solvency. Operational scale via mergers is believed to be how sustainable profitability can be restored to the domestic oil and gas business. That doesn't negate the earlier mantra that E&P managements needed to embrace Shale 3.0, which means keeping a company's production flat, while using any surplus cash generated by the business to pay down debt or be returned to shareholders. The corollary required that controlling costs, i.e., reducing expenses, overhead and employees, must be pursued aggressively. Disposing of non-essential assets should also be a part of strategies.

<u>The Shale Revolution</u>

The energy future of the United States foreshadowed an increasing reliance on foreign energy supplies, often coming from countries unfriendly to us, thereby forcing us to surrender some of the economic and political power we had amassed

The shale revolution's evolution has fit neatly into three phases, each of which was clearly discernable. Shale 0.0, the initial phase, consisted of exploring for the resource and overcoming the technological challenges of producing the trapped hydrocarbons. For historical reasons, Shale 0.0 began with natural gas. It was driven by high gas prices, the result of concern over physical shortages that would force the country to begin importing more gas from Canada and expensive liquefied natural gas (LNG) from international sources. Coupled with declining U.S. oil production, the energy future of the United States foreshadowed an increasing reliance on foreign energy supplies, often coming from countries unfriendly to us, thereby forcing us to surrender some of the economic and political power we had amassed. Such a future also dictated that our military would be playing a much greater role in securing the steady flow of foreign hydrocarbons the U.S. economy needed.

Shale was often referred to as a "junk" zone by drillers who were only hoping to get through them as quickly and easily as possible

Shale formations were known to contain significant volumes of hydrocarbons, but attempts to drill into and through them had often proven problematic. Shale was often referred to as a "junk" zone by drillers who were only hoping to get through them as quickly and easily as possible, as getting stuck often meant huge costs and potentially lost wells. Engineers at Mitchell Energy & Development Corp., a small Houston-based E&P and land development company, had worked for years advancing the science of drilling in shale and unlocking its resources. The engineers' efforts initially were undertaken in conjunction with research of U.S. government scientists begun in the 1970s. The drive to unravel the shale mystery grew more urgent, as Mitchell Energy was running out of gas reserves to fulfill its long-term contracts to deliver natural gas to the Chicago market. Much of that supply was coming from the company's leases in the Barnett region of North Texas, which had shale underlying it. The reality of running out of gas was confronting the company's management in 1997. Failure to deliver the contracted volumes would jeopardize Mitchell Energy's future. Finding new natural gas supplies became the primary focus of management, although several engineers continued to experiment with techniques for unlocking the gas trapped in the Barnett shale, often to the consternation of their bosses.

A chance encounter in 1997 between Nicholas Steinsberger, a young engineer in charge of the fracking effort in the Barnett basin for Mitchell Energy, and an engineering friend with competitor Union Pacific Resources, led to his becoming aware of their development of "slick water" fracturing technology that seemed to be having success in unlocking the shale's resources. It wasn't until 1998, however, that the gas flow from the S.H. Griffin No. 3 well, fracked with this slick water mixture, was exceeding the volume produced from any Barnett well after 90 days. Thirty days later the well was still producing gas at historical rates. The "aha moment" was achieved, although skeptics remained within Mitchell Energy.

Between 1999 and 2001, Mitchell Energy grew its gas production to 365 million cubic feet per day, a 250% increase over the two-year period. This flow, combined with the potential for further production growth, led Devon Energy to purchase Mitchell Energy for $3.1 billion, making George Mitchell, the founder of the company, a billionaire overnight. Industry competitors were skeptical of why Devon was willing to pay so much for what still seemed to be an unproven technology, but the subsequent years proved the skeptics wrong – at least in regard to tapping the trapped hydrocarbons.

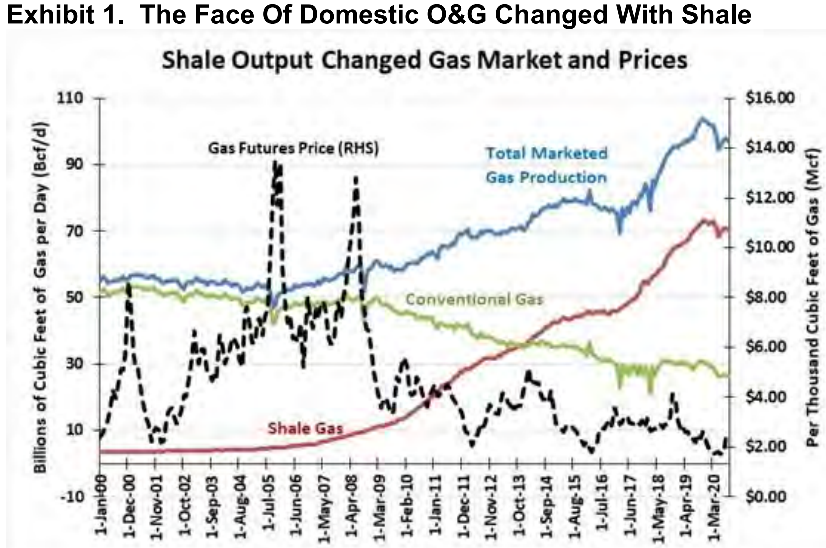
Mitchell Energy's success, and its sale to Devon Energy, kicked off Shale 1.0 – the great land grab

Mitchell Energy's success, and its sale to Devon Energy, kicked off Shale 1.0 – the great land grab. Producers began in the Barnett, but gradually started targeting other gas-rich basins possessing shale formations. The land rush was epitomized by the late Audrey McClendon, founder of Chesapeake Energy. Rushing from courthouse to courthouse, he and his brokers researched land titles and offered outsized lease bonuses in order to lock up prospective shale acreage before competitors did. While most landmen, as lease title researchers are known, were working for producers, some soon began speculating on leases on their own, knowing the likelihood was high that some producer, late to the race, would reward them with a premium for the acreage spreads these landmen had been able to accumulate.

Following the land rush, natural gas drilling took off, and soon gas supply was growing

Following the land rush, natural gas drilling took off, and soon gas supply was growing. The rise in natural gas prices, as we entered the 2000s, had been driven by growing demand and falling domestic output. This reality forced gas buyers to offer higher prices to induce producers to find more supply.

Exhibit 1. The Face Of Domestic O&G Changed With Shale



Source: EIA, PPHB

High gas prices encouraged producers to step up drilling, but it also encouraged them to push shale drilling technology

As expected, high gas prices encouraged producers to step up drilling, but it also encouraged them to push shale drilling technology. Producers and service companies began experimenting with ways to improve horizontal drilling and hydraulic fracturing techniques, which led to a steady progression in improved well efficiency, i.e., production per foot of lateral drilled.

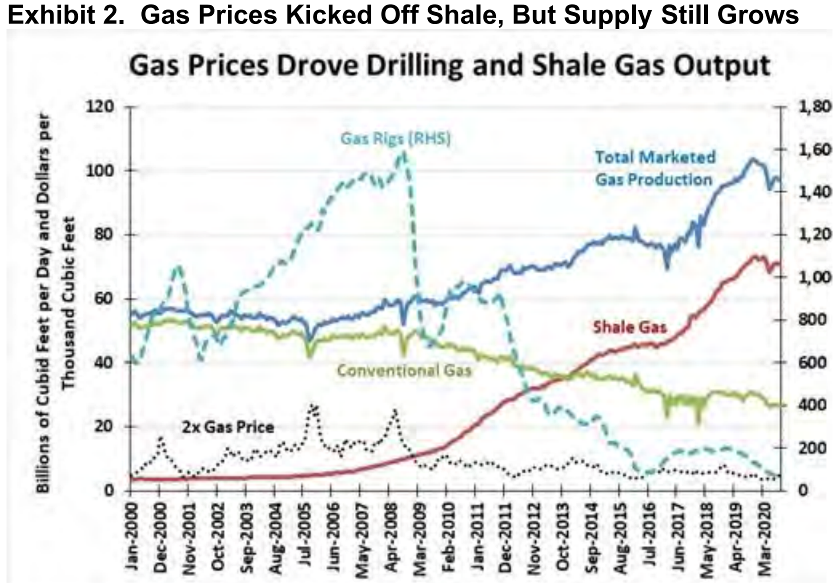
When we add active gas drilling rigs to the chart of gas production and pricing in Exhibit 2 (next page), we see how the drilling effort led to a rapid growth in gas shale output, which in turn caused prices to fall and drilling, subsequently, to decline. What didn't happen was shale production ceasing to climb

As natural gas prices were cut in half from 2005-2006 to the early years of the 2010s, profitability of the shale effort was challenged. A huge debate commenced about whether shale gas drilling would, or could, ever be profitable. Shale 1.0 showed this revolution would consume huge sums of money, due to inflated lease acreage expense, costly wells and expensive well completions, before sufficient gas volumes could be produced to repay the investment, let alone earn a return. Near-term profits were sacrificed for supply.

Images of huge future profits from shale gas wells became a magnet for capital

In a financial environment shaped by extremely low interest rates that forced investors to seek returns anywhere they could find them, images of huge future profits from shale gas wells became a magnet for capital. Wall Street was more than willing to help new and established E&P companies raise equity and debt to fund shale drilling efforts. Private equity funds proliferated, pouring money into new start-ups headed by E&P professionals willing to leave established companies in search of 'pots of gold' under the shale rainbow. Falling natural gas prices were an ominous sign, but that merely forced innovators to try other shale venues in search of the elusive shale profits. While the technical success of shale gas exploitation engineered by Mitchell Energy drove Shale 1.0, the search for new frontiers put the E&P industry on the road to one of the most ruinous episodes in America's oil and gas industry history.

Exhibit 2. Gas Prices Kicked Off Shale, But Supply Still Grows



Source: EIA, Baker Hughes, PPHB

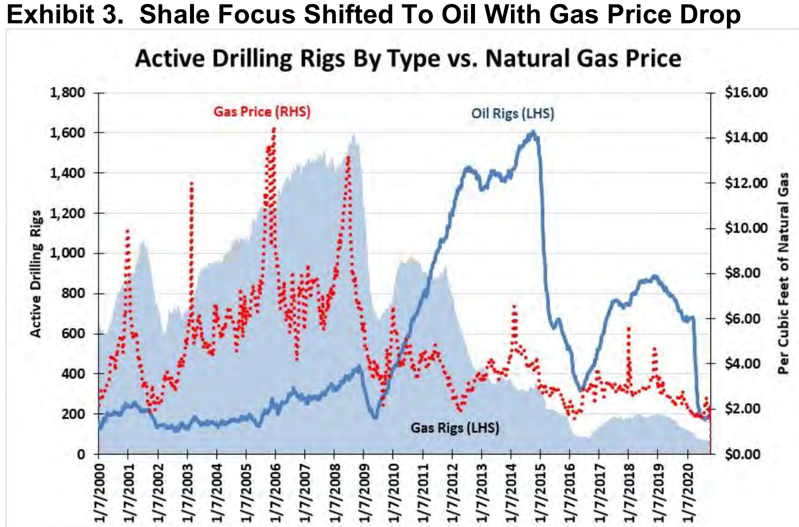
E&P executives rapidly shifted their focus from low-priced gas to high-priced oil

The 2008-2009 financial crisis and resulting recession, which was then followed by the slowest economic recovery since the end of World War II, marks the point at which the shale revolution shifted from a natural gas focus to one targeting crude oil. Whether this shift was facilitated by the economic environment, or would have occurred naturally due to falling gas prices is immaterial: E&P executives rapidly shifted their focus from low-priced gas to high-priced oil. The existence of substantial shale formations below the Permian Basin caused E&P companies to experiment with the shale

The prospect of $100 a barrel oil was viewed as key to solving the financial problems many shale producers were dealing with

technology. Those initial experiments proved successful, offering hope for a revival in Permian Basin drilling, as well as a providing a ticket to E&P profitability. The prospect of $100 a barrel oil was viewed as key to solving the financial problems many shale producers were dealing with. The oil rig count began climbing as we exited the 2009 recession. The siren song of $100 a barrel oil drove the rig count up. We can see how that hope was turned into reality, as there was a dramatic increase in oil rigs coming out of the 2009 recession. The rig count soared to a modern peak in mid-2014, which coincided with the peak in oil prices. We have rued the result.

Exhibit 3. Shale Focus Shifted To Oil With Gas Price Drop

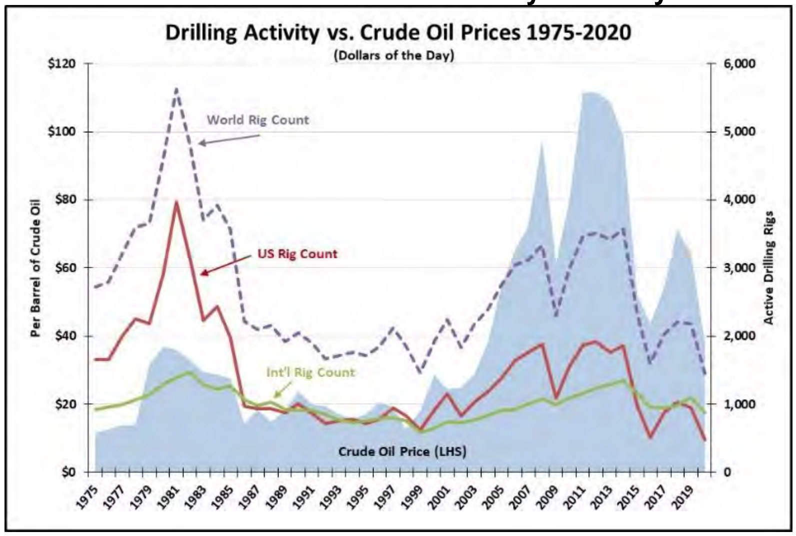


Source: EIA, Baker Hughes, PPHB

The difference in the two phases was the emphasis on scale of operation, as the key to reducing costs

The shift from a natural gas focus to crude oil drove the transition from Shale 1.0 to Shale 2.0. The difference in the two phases was the emphasis on scale of operation, as the key to reducing costs. This focus on scale pushed the move to consolidate acreage holdings. Where Shale 1.0 was focused on merely securing shale acreage, companies now needed to consolidate their acreage holdings to enable the use pad drilling (multiple wells at one location) as a cost reducing technique. Employing pads for multiple wells increased drilling efficiency – faster rig moves – and facilitated completion activity, as frac equipment could be set up once to complete multiple wells. As the volumes of sand and water necessary for drilling and completion activity escalated, acreage concentration and pad usage enabled improved logistics management - a cost control discipline. By concentrating acreage holdings, company engineers were able to begin mapping more concentrated drilling programs that would facilitate draining a greater portion of the resources trapped in the shale acreage another move to attempt to boost profitability.

Exhibit 4. Crude Oil Prices Drove Industry Recovery In 2000s



Source: EIA, Baker Hughes, PPHB

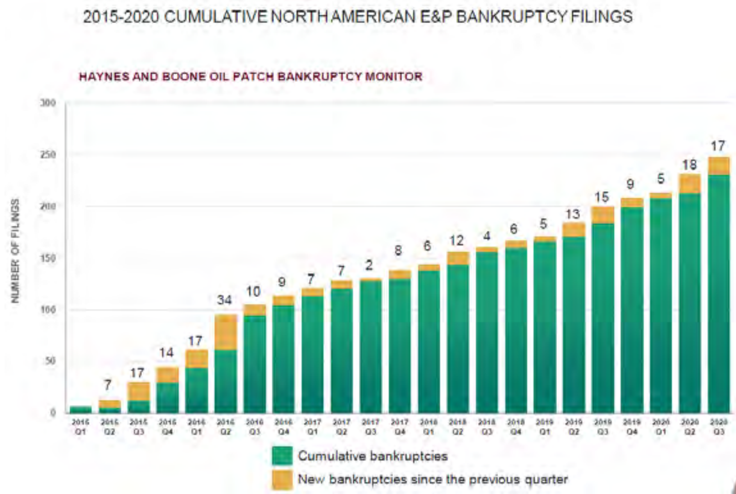
It is interesting to see how little the rig count changed during the long period of flat commodity prices of the 1980s and 1990s

Exhibit 4 shows what happened to the rig count – U.S., international and world – when oil prices fell in the early to mid-1980s. Oil prices remained largely flat for about a 17-year span, during which time the rig counts slowly declined. As oil prices began to move higher, and then substantially higher in the mid-2000s, both the U.S. and international rig counts climbed. While the relationship between oil prices and drilling is well established, it is interesting to see how little the rig count changed during the long period of flat commodity prices of the 1980s and 1990s.

Debt payment schedules, combined with investors and lenders unwilling to provide more capital to the industry, set Day of Reckoning dates for companies

The industry's financial problems with shale became very evident when oil prices crashed in 2014. With no recovery in natural gas prices, the physical and financial realities of Shale 2.0 forced a recognition that something needed to change, and quickly. The heavy capital investment required to launch a shale drilling effort – high priced acreage, expensive well drilling and completion costs, and costly overheads – that had largely been financed with debt, forced companies to re-evaluate their strategies. Low commodity prices eliminated the option of drilling more wells to boost output and revenues to overcome financial losses. Debt payment schedules, combined with investors and lenders unwilling to provide more capital to the industry, set Day of Reckoning dates for companies. The bankruptcy count among E&P companies since the 2014 oil price crash is approaching 250 filings. We doubt that new filings have ended.

Exhibit 5. Producer Segment Hurt By Debt And Low Prices



Source: Haynes and Boone

The recent merger announcements mark companies implementing the shift from Shale 2.0 to Shale 3.0

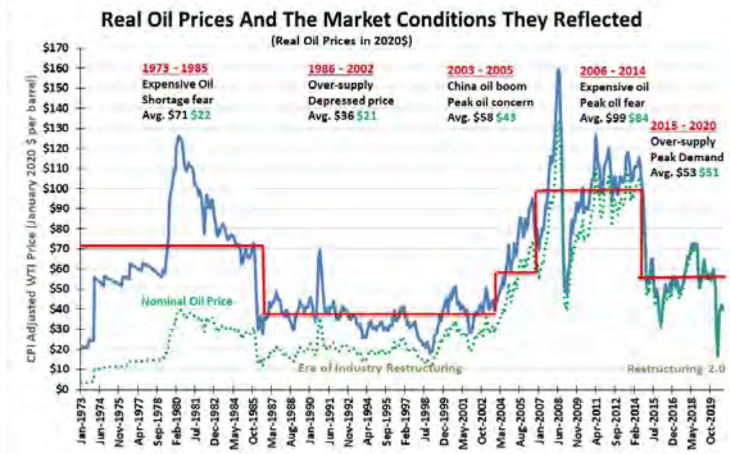
Shale 3.0 was forced on the industry. It means spending money only to sustain production, cutting costs, and using any surplus cash to pay down debt. Lastly, it has caused managements to consider exit strategies. The recent merger announcements mark companies implementing the shift from Shale 2.0 to Shale 3.0. Is this an admission that living under Shale 3.0 is just too difficult and frustrating for some companies, as it goes against the grain of traditional E&P executives? Growing reserves and production is what is in their blood and how they always have been compensated. How do you get paid for saving pennies? Grinding on expenses is hard work, and doesn't make you popular with your employees who are the ones being ground.

<u>The Oil Industry of the '80s and '90s</u>

Oil prices in both real and nominal terms were essentially flat after the oil price crash of 1986 through to the start of the China oil demand boom in 2003

If Shale 3.0, or maybe it will become 4.0, marks the start of a major transformation of the domestic oil and gas business, people will begin speculating on the industry's eventual makeup. Maybe a review of the last great industry transformation that occurred in the late 1990s and early 2000s will provide a perspective on what the future may look like. To understand that transformation, and to set the stage for a discussion about the current restructuring, we need to review the industry's history from the late 1980s to the late 1990s. Note that oil prices in both real and nominal terms were essentially flat after the oil price crash of 1986 through to the start of the China oil demand boom in 2003.

Exhibit 6. 1970s High Oil Prices Led To Years Of Low Prices



Source: EIA, BEA, PPHB

While jawboning its fellow members to stop their production cheating, Saudi Arabia cut its own output to provide support for the OPEC oil price

The two jumps in oil prices during the 1970s - 1973 and 1978 - took them to a level never seen in modern time, both in real and nominal terms. The Arab oil boycott-driven oil price spike of 1973 exposed the vulnerability of the United States, as well as other Western economies, to energy blackmail. The high oil price, coupled with the expectation for prices to remain high for the foreseeable future, drove producers to seek hydrocarbon resources everywhere outside of the Middle East. Not surprisingly, the industry was successful in adding to the world's resources and production. The additional supplies put further pressure on Middle East members of the Organization of Petroleum Exporting Countries (OPEC) who were already struggling with falling demand due to high oil prices. Moreover, OPEC members were enjoying increased wealth from high oil prices, and were not interested in it stopping. Economics, however, dictated that the additional supply would soon depress prices and weaken the role of OPEC as the supplier of the marginal barrel of oil for the global market. As OPEC was structured, one member controlled the organization's marginal barrel that established the world's oil price. The pressure on Saudi Arabia to support the cartel's target price grew dramatically. While jawboning its fellow members to stop their production cheating, Saudi Arabia cut its own output to provide support for the OPEC oil price. This strategy saw Saudi Arabia go from producing over 10 million barrels per day (mmb/d) in 1981, to 3.5 mmb/d by 1983, but OPEC's price steadily fell.

Exhibit 7. Saudi Arabia Oil Production 1975-2020

Source: Trading Economics

The kingdom knew what the impact would be on global oil prices

Global oil demand recovered somewhat after 1983, which enabled OPEC and Saudi Arabia to restore some of their reduced production. The OPEC cheating resumed and Saudi Arabia grew exasperated as it tried to support what was an unsustainable oil price. Saudi Arabia declared it would no longer restrain its output, and, in fact, would step up production to boost its revenues. The kingdom knew what the impact would be on global oil prices. They fell to below $10 per barrel, at which point the pain for fellow OPEC members grew intense and they finally agreed to begin adhering to the organization's production quota. Oil prices recovered, helped by Saudi Arabia reducing its production to speed the recovery. By the final years of the 1980s, the kingdom's production was in the 5.5-6.0 mmb/d range, on its way to 8 mmb/d.

It only required about six months of low oil prices to restore sanity among OPEC members

During the 1980s, oil prices went from the mid-$30 a barrel in 1981 to $27-$28 by 1985, at which point oil prices collapsed, with Saudi Arabia's war against its fellow OPEC members, to $11 by mid-1986. It only required about six months of low oil prices to restore sanity among OPEC members. By early 1989, oil prices were back to $20 per barrel.

The oil price rout crashed oilfield activity, forcing E&P and oil service companies to shut down activity, idle equipment, lay off employees, and eventually many of them failed financially

The oil price rout crashed oilfield activity, forcing E&P and oil service companies to shut down activity, idle equipment, lay off employees, and eventually many of them failed financially. The devastation of the global oil industry was extensive and long-lasting. For the United States, the demand decline, as a result of the 1970s oil price spikes, required 10 years to recover. Elsewhere in the world, the demand response didn't require quite as long a recovery period, but as the U.S. was (is) the world's largest oil consumer, what happened here cast a shadow on the global oil market.

The Asian Tiger Miracle

As the U.S. and global oil industry slowly recovered from the mid-1980s oil price crash, the economic miracle of Asia was gaining steam. Globalization was underway. World trade was growing faster than the world economy itself. By the early 1990s, Japan was considered the superpower economy to be emulated by countries everywhere. In fact, organizational gurus were all studying and showcasing the management styles of Japanese corporations and demonstrating why companies everywhere should be copying them.

The rise of the Asian tigers was driving economic growth, and with that growth came rapid increases in crude oil consumption

By the mid-1990s, what was going on in Asia, especially among the "Asian tigers" – South Korea, Taiwan, Hong Kong and Singapore – and the "new tigers" of Malaysia, Indonesia, Thailand and the Philippines, along with China's Guangdong Province, was not being lost on OPEC's members. Rather than relying on self-sufficiency and high trade barriers that had been the economic development canon since the 1960s, that approach to growth was cast aside by these countries in favor of policies promoting trade and the global economy. The tiger economies were growing quickly, leading to rapidly rising incomes. As Daniel Yergin pointed out in <u>The Quest: Energy, Security, and the Remaking of the Modern World</u>, Singapore, a beleaguered city-state when it gained independence in 1965, surpassed England's per capita GDP, on a purchasing power parity basis, by 1989. The rise of the Asian tigers was driving economic growth, and with that growth came rapid increases in crude oil consumption.

In the seven years from 1990-1997, Asia's share of world oil consumption jumped from 20.9% to 27.2%

To appreciate how rapidly Asian oil demand was growing, based on BP statistics, Asian oil consumption went from 17.2% of world oil use in 1980 to 20.9% in 1990. In the seven years from 1990-1997, Asia's share of world oil consumption jumped from 20.9% to 27.2%. Between 1997 and 2000, the bursting of the Asian tiger miracle saw the region's oil share only grow from 27.2% to 27.7%. What this meant was that between 1990 and 1997, world oil consumption grew 11.1%, while Asian use was up 44.8%. Asian demand accounted for 84.2% of world oil consumption growth during this period. The dramatic slowdown after 1997 was the root of the oil market's problems by the end of the 1990s.

After four days of meetings and discussions, the ministers agreed to lift OPEC's production quota by 2 mmb/d

Mr. Yergin described what happened in 1997 and 1998. In November 1997, the OPEC petroleum ministers held their regular meeting in Jakarta, Indonesia. The buoyant Asian economy was a focus of the discussions, but more importantly Saudi Arabia was intent on stopping the cheating of various OPEC members who were overproducing their quotas in order to boost incomes. After four days of meetings and discussions, the ministers agreed to lift OPEC's production quota by 2 mmb/d. This was in keeping with the reality that world oil consumption had risen by more than 2 mmb/d between 1996 and 1997, and the International Energy Agency predicting oil consumption would rise by another 2 mmb/d in 1998.

Underneath the headline of OPEC's press release was the reality that the quota increase meant the cheating members, who were producing at their maximum outputs, would be unable to participate in the expanded quota. Therefore, most of the production increase would accrue to Saudi Arabia, as well as several smaller Middle

Less than two months after the OPEC meeting, a full-scale panic was raging across much of Asia

East producers. The problem, however, was that the Asian miracle was in the early stages of unraveling. According to Mr. Yergin, the head of the International Monetary Fund office in Jakarta had dinner with two delegates attending the OPEC meeting. During their meal, this official described to the delegates how the "overheated and overbuilt" condo and office markets in Bangkok had caused a collapse in July 1997 of Thailand's currency. That had contributed to the fall of the value of other currencies in the region, along with various Asian stock markets. Less than two months after the OPEC meeting, a full-scale panic was raging across much of Asia. Companies were becoming bankrupt; people were being thrown out of work and governments were teetering. From extremely high growth rates, Asian economies were heading into a virtual depression. Oil demand evaporated, causing oil prices to crash.

Exhibit 8. How OPEC Misread The Asian Tiger Miracle

Source: EIA, PPHB

Prices were still above $20 at the time of the meeting, so while the warning of impending economic chaos was considered, it came too late

To appreciate the significance of the timing of the OPEC meeting, the lifting of its production quota by 2 mmb/d, the ending of the Asian tigers' economic miracle, and the crashing of oil prices on the industry's future, one only needs to look at the history of oil prices for 1986-2000. As oil demand was surging in 1986, oil prices traded between $20 and $25 per barrel, with prices crossing the upper end of this range during the fourth quarter. As 1987 opened, oil prices began sliding, but they stabilized near the bottom of the trading range. Given oil demand forecasts, a $20 a barrel price was not considered unreasonable, especially as projections called for higher prices in the future. Note in Exhibit 8 how oil prices ticked up into the mid-$20s, as OPEC ministers began preparing for their November meeting. Prices were still above $20 at the time of the meeting, so while the warning of impending economic chaos was considered, it came too late. OPEC had already baked in the quota hike. This may have been because the meeting's outcome was more influenced by Saudi Arabia wanting to correct the ongoing cheating within OPEC, rather than the organization's efforts to capture market share in the growing Asian region.

Instead of 2 mmb/d of demand growth in 1998, it grew by only 230,000 barrels per day, a 0.3% increase instead of the expected 2.7%

The confidence OPEC had about a continuation of the Asian tigers' miracle was soon dashed. Instead of 2 mmb/d of demand growth in 1998, it grew by only 230,000 barrels per day, a 0.3% increase instead of the expected 2.7%. At the end of November 1997, the time of the OPEC meeting, WTI was trading at $18.76 per barrel. One year later, after the Asian economic crash and oil demand evaporated, crude oil was at $11.37, a 25-year low. In the interim, OPEC petroleum ministers worked to correct their production mistake. In March 1998, they agreed to cut the organization's quota by 1.245 mmb/d, which they followed up with a second cut in June 1998 of 1.355 mmb/d, bringing the year's total cut to 2.6 mmb/d, completely erasing the November 1997 quota hike. The problem was that demand was collapsing faster, while non-OPEC supplies were growing, even though Norway had agreed to cut its output by 3% in the spring of 1998. The global oil market was devastated by OPEC's failure to cut output further at its November 25-26, 1998, meeting. What also bothered the oil market was the inability pf OPEC ministers to agree to extend their production cuts beyond the scheduled June 1999 ending. OPEC ministers did agree to meet in March 1999. When the news of the meeting's outcome was announced, oil prices sank, as the market sensed that only time and a healthy economic recovery would produce higher prices.

Oil Industry Restructuring 1.0

We discussed how regulatory, economic and technological changes underway in the oil business contributed to companies adjusting their strategies that led to the massive industry restructuring

During 1998, while the oil market wrestled with falling prices, industry executives began executing on changed strategies dictated by a new market reality. The events of 1998 marked the start of a major restructuring of the international oil industry, which was driven by changing marketplace conditions. To gain a perspective on what was underlying this great restructuring, we called our friend, Frank Knuettel. As energy analysts in the 1970s to 2000s, we had met a number of times at various industry and analyst functions. We got to know each other better when we served on the board of the National Association of Petroleum Investment Analysts (NAPIA) together. Mr. Knuettel was a top-ranked integrated oil company analyst by Institutional Investor (II) magazine for a number of years. He joined the investment broker Paine Webber in 1997, just as the industry restructuring began, and retired in 2000. In a conversation early last week, we discussed how regulatory, economic and technological changes underway in the oil business contributed to companies adjusting their strategies that led to the massive industry restructuring.

Domestic oil production had peaked in 1971 and was continuing to decline, forcing the integrated producers to have to import increasing volumes of oil. The pace of the domestic oil output decline slowed, but it wasn't reversed, despite healthy oil prices in the late 1990s. The oil war of the 1980s destroyed the domestic industry's capacity, which needed years to recover. Flat and low oil and gas prices did not help accelerate an industry recovery, so U.S. oil imports grew.

Many companies downsized their domestic E&P efforts and expanded internationally. The lack of domestic exploration success, especially for natural gas, led John Laborde, chairman of Tidewater Inc., the world's leading offshore supply vessel operator, to label the Gulf of Mexico the "Dead Sea" in an analyst presentation in the late 1990s. Gas was selling for less than $1 per thousand cubic feet, and offshore drilling and developing activity was grinding to a halt.

Tightened emissions regulations for refined products pushed companies to install new refining technologies that increased the sophistication of domestic refineries

Tightened emissions regulations for refined products pushed companies to install new refining technologies that increased the sophistication of domestic refineries. The more sophisticated refineries demanded changes in the slates of crude oil inputs, which further emphasized the need for different blends of oil. The increased sophistication enabled refiners to adjust their outputs to meet shifting market needs. As the 1990s progressed, it became evident that certain majors were further along than others in this transition. This made their downstream assets more valuable, and, in some cases, their international E&P operations, too. These subtle competitive shifts were often not adequately reflected in share prices, which created acquisition opportunities.

At the same time, a fledgling oil futures market was emerging

At the same time, a fledgling oil futures market was emerging. It contributed to companies being able to disintegrate their upstream (finding and producing) from their downstream (refining) businesses. The degree of separation was impacted by the relative position various upstream divisions played in supplying their company's downstream needs. The greater the percentage of refinery runs supplied by a company's upstream operations, the less incentive it had to hedge the prices of either its crude oil production or its refined product output, although there was more willingness to hedge the latter to protect profits. On the other hand, a company that supplied a low level of its own refining needs could benefit by hedging the prices of international supplies it needed to purchase.

In response to the question of why the major integrated oil companies combined, Mr. Knuettel suggested six key reasons. He listed them as:

1. Reducing costs,
2. Diversification of assets,
3. Enhancing stock values,
4. Responding to crude oil price volatility,
5. Enhancing market power, and
6. Synergies from combinations.

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Most of the major oil mergers during this period had employee reduction targets of roughly 7%

Reducing costs is pretty obvious, and relatively easy to achieve. One headquarters' staff and its associated expense is eliminated in a merger. Duplicate offices and operating bases are eliminated or consolidated, but the big cost reductions come from eliminating employees. Most of the major oil mergers during this period had employee reduction targets of roughly 7%. Whether those targets were actually attained is unknown, but it is interesting that the 7% figure appears in most merger announcements, signifying that this was a number investors expected as cost-savings from a deal.

Diversification of assets was important, as companies heavily dependent on the U.S. sought greater access to international opportunities and production. There was also a recognition that natural gas was beginning to play a more important role in meeting the energy needs of both the U.S. and the world's economy.

Everyone was hoping that consolidation would bring increased revenues, but importantly, widened profit margins. Greater returns anticipated from combinations were expected to be recognized in the stock market with higher per-share valuations.

A way to deal with increased crude oil price volatility is to have access to multiple sources of supply. That diversification enables the management of crude streams to not only dampen price swings, but potentially to improve profit margins. The wider the spread of E&P opportunities helps to reduce oil price volatility.

The emergence of the 12-month strip of futures prices became a measure oil companies could reasonably employ in business forecasts, well economic analyses, and acreage and company acquisitions

But there was another development in the financial community that carried huge implications for the oil business. That was the development of the NYMEX futures market. As Mr. Yergin pointed out, after the market chaos of the 1930s, industry pricing was controlled by the Texas Railroad Commission and then by OPEC. Now major financial institutions, as well as commodity traders and oil and gas companies, could hedge the price risk on some or all of their production, providing greater cash flow and profitability assurance. The emergence of the 12-month strip of futures prices became a measure oil companies could reasonably employ in business forecasts, well economic analyses, and acreage and company acquisitions. This helped make deals easier, as all parties could settle around the market's assessment of future prices as the valuation tool in deals.

In the 80-plus years following the end of the Standard Oil Trust domination, the industry had seen its market power fall from highly-concentrated to highly-dispersed

Ever since the break-up of the Standard Oil Trust in 1911, at a time when it controlled 90% of the domestic refining business, the leaders of the companies spun out of the trust were desirous of gaining greater marketing clout. In the 80-plus years following the end of the Standard Oil Trust domination, the industry had seen its market power fall from highly-concentrated to highly-dispersed. In fact, people were amazed the Exxon/Mobil Oil merger was allowed to proceed with only minor divestitures, but it was largely due to the fact that the combined entity still had less than 15% of the total U.S.

market for gasoline. As a condition for approval of the merger by the Federal Trade Commission, the combined company agreed to shed 2,431 gasoline stations in the northeast United States, California, Texas and Guam. These were regions where the combined market share was in the 20% or greater range, clearly meeting the anti-competitive threshold. The new company also was required to dispose of other assets, but none were considered critical to the rationale underlying the merger.

The new ExxonMobil cited its ability to undertake projects of any size anywhere in the world, something neither of the individual companies could state prior to the merger

While many people equate synergies with reducing costs, they are actually two very different concepts. Synergies come from integrating the strengths of one company in order to offset the weaknesses of the other. The combined entity may then be able to deliver even greater returns from projects and business units than either one could deliver on its own. The new ExxonMobil cited its ability to undertake projects of any size anywhere in the world, something neither of the individual companies could state prior to the merger. This collective strength would prove important given competitive threats, as well as unique business opportunities, internationally.

Merger deals, especially when done during times of low commodity prices, offer the ideal time to aggressively scrutinize all expenses and operating policies

Reducing costs is a more straight-forward concept – figuring out how to do more with less. While meataxes are not the preferred method of dealing with costs, finding better approaches to operating the business is what is required. That may mean operating with fewer people, switching vendors to less expensive ones or who are more efficient, or exiting low-profit business lines. Merger deals, especially when done during times of low commodity prices, offer the ideal time to aggressively scrutinize all expenses and operating policies.

How Oil Industry Restructuring 1.0 Happened

It was the shock of BP agreeing to acquire Amoco for $48 billion to improve its presence in the Americas that got everyone's attention

Nineteen ninety-eight proved to be a watershed year for the global oil industry. On May 4, Atlantic Richfield (ARCO) announced an agreement to acquire Union Texas Petroleum Holdings Inc. for $2.47 billion. While a significant industry transition, it was the shock of BP agreeing to acquire Amoco for $48 billion to improve its presence in the Americas that got everyone's attention. The real shocker, however, was the December 2nd announcement that Exxon and Mobil Oil would merge in an $77.2 billion stock and debt deal, barely days after oil prices fell below $11 a barrel, and OPEC had failed to act to stem the price slide. Before year-end, French oil company, Total SA announced a deal to acquire Petrofina SA.

Long-time oil analyst, Fadel Gheit of Fahnestock & Co., called the Exxon/Mobil Oil merger, "The deal of the century." The four deals in 1998 commenced the wave of oil industry restructuring that dominated industry news for the next several years. A noteworthy E&P deal in 1997 – Burlington Resources acquiring Louisiana Land & Exploration – may have foreshadowed what was to come starting in 1998, but few people grasped the significance. The list of major merger transactions (not a complete list) is shown in Exhibit 9. It shows the year of the deal, the acquiror, the acquired company, and the estimated deal value (US$ in billions).

Exhibit 9. Industry Restructuring Mergers Of Late '90s

1997	Burlington Resources	Louisiana Land & Exploration	3.00
1998	Atlantic Richfield (ARCO)	Union Texas Petroleum Holdings Inc.	2.47
1998	BP	Amoco	49.00
1998	Exxon	Mobil Oil	77.20
1998	Chevron Corp.	Rutherford-Moran Oil Corporation	0.09
1998	Total SA	Petrofina SA	39.00
1999	BP-Amoco	Atlantic Richfield (ARCO)	26.80
2000	Total Fina	Elf Aquitane	54.30
2000	Chevron Corp.	Texaco	35.00
2000	Andarko Petroleum	Union Pacific Resources	4.40
2001	Andarko Petroleum	Berkeley Petroleum Corp.	1.60
2001	Conoco	Phillips Petroleum	15.20

Source: Various, PPHB (collected from sources deemed reliable; dates may vary due to announcement versus completion; values may include debt)

What concerned Texaco's Mr. Bijur in early December 1998 was that no one had predicted oil prices falling to their lowest inflation-adjusted level in 49 years, and staying there

To appreciate how challenging the environment of the late 1990s was, we refer to an early January 1999 article in *The New York Times*. It opened with comments about the Wall Street oil analysts meeting in early December 1998 with the management of Texaco. CEO Peter Bijur broke with tradition at the meeting, as he only provided an industry outlook for 1999, as opposed to the normal five-year forecast. As Mr. Bijur said, "It would be ludicrous," to talk about the industry outlook for the next five years. Why was he uncertain? It was due to the oil price volatility the industry was living through. In 1997, WTI averaged $20.60 a barrel. The following year, it was only $14.39, a 30% drop. A more significant comparison was that oil prices averaged $13.13 a barrel in 4Q1998, down 34% from a year earlier. The major U.S. oil companies were expected to post earnings declines of 32% to 90% for the quarter. A year earlier, the three largest U.S. oil companies reported the biggest quarterly profits in their histories. The surging profitability in 1997 was largely due to oil prices averaging $19.94 a barrel, well above the $14 price most companies suggested was their break-even point for wells. What concerned Texaco's Mr. Bijur in early December 1998 was that no one had predicted oil prices falling to their lowest inflation-adjusted level in 49 years, and staying there.

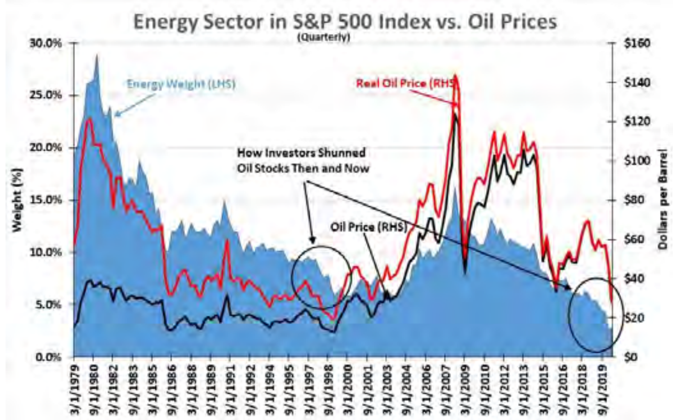
The profit collapse turned investors away from energy stocks

Douglas Terreson, at the time, the senior oil analyst with Morgan Stanley Dean Witter, said "'Blood bath' may be an understatement" in describing the forthcoming 4Q1998 oil industry earnings results. It was not surprising that earnings were collapsing given the compression of profit margins. Mr. Terreson was estimating that the industry's oil-refining profit margins in 1998 would be in the 5%-6% range, down from his prior estimate of 8%-9%. The profit collapse turned investors away from energy stocks, much like what has been

"We confess to underestimating the response of the equity market to the decline in oil prices"

happening in recent years. Interestingly, David Bradshaw, an oil analyst with Donaldson, Lufkin & Jenrette Securities, wrote to clients in 1998: "We confess to underestimating the response of the equity market to the decline in oil prices." That statement is equally valid today! And would be valid for the same reason as in 1998. One can see how the weighting of energy stocks within the S&P 500 dropped in the late 1990s versus recently by examining the circles in Exhibit 10. The difference is that today the weightings are considerably lower than they were 20 years ago.

Exhibit 10. Energy Out Of Investor Favor In 1990s And Now



Source: S&P, PPHB

They pointed out that the roster of the top oil companies was essentially the same as in 1911 when the Standard Oil Trust was broken up

Mr. Terreson is credited with playing a role in helping drive the oil industry mega-mergers. The stage for his role was set, according to Mr. Yergin, when Morgan Stanley bankers Joseph Perella and Robert Maguire made a presentation in February 1998 to oil industry executives. They pointed out that the roster of the top oil companies was essentially the same as in 1911 when the Standard Oil Trust was broken up. As a result, they said, "Were he alive today, John D. Rockefeller would recognize most of the list. Carnegie [steel], Vanderbilt [railroads], and Morgan [banking], on the other hand, would have difficulty with similar lists for their industries." This seemingly was the bankers' clarion call for industry consolidation. With all due respect, investment bankers are always in favor of M&A activity, since that is how they get paid.

"'Unparalleled globalization and scale' resulting from mergers – combined with greater efficiency and a much wider book of opportunities – would lead to 'superior returns and premier valuations'"

The Morgan Stanley bankers were then supported by Mr. Terreson's paper, "Era of the Super-Major," that laid out the case for why mergers would be good for the industry. From The Quest: "'Unparalleled globalization and scale' resulting from mergers – combined with greater efficiency and a much wider book of opportunities – would lead to 'superior returns and premier valuations.' In short, larger companies would be more highly valued by shareholders. And, by implication, those companies that were smaller and less highly valued would be at risk." This argument fits exactly with the observations made by Mr. Knuettel.

We were entering an era where petroleum technology made it possible to find, produce and refine oil much more efficiently, thus supply was less of a concern for companies

The oil supply and demand environment set the stage for the industry consolidation. After years of stable oil prices and demand met by international oil supply, optimists began to argue that cheap oil was beginning to run out. For U.S. producers, that seemed to be the reality. We were entering an era where petroleum technology made it possible to find, produce and refine oil much more efficiently, thus supply was less of a concern for companies. With low oil prices, oil executives had to become obsessive about cutting costs. As Lee Raymond, Chairman and CEO of Exxon Corp. said, “you cannot count on the market to bail you out of bad decisions.”

Thus, the merger wave. As Leo P. Drollas, deputy director of the Center for Global Energy Studies in London put it: “The industry is looking ahead and seeing low oil prices as far as they can see. The mergers are a defensive action." The obsessive focus on internal cost-cutting was no longer sufficient, according to Mobil Oil Chairman and CEO Lucio A. Noto. He pointed out the challenge for oil company executives: "The easy things are behind us. The easy finds. The easy cost savings. They're done. We tend to do the smart thing when times are tough. And times are tough now." That was his rationale for the merger with Exxon Corp.

According to Mr. Yergin, Lord John Brown, the CEO of BP, recognized as early as 1995 that his company needed to change to survive in the petroleum future foreshadowed by the 1990s

As we look to the late 1990s restructuring deals, it was evident companies felt they needed to execute on all six rationales laid out in our conversation with Mr. Knuettel. According to Mr. Yergin, Lord John Brown, the CEO of BP, recognized as early as 1995 that his company needed to change to survive in the petroleum future foreshadowed by the 1990s. He convinced his board of the need for consolidation, and then proceeded to act. His first call was with Mr. Noto of Mobil Oil, but after extensive discussions, the deal was called off. He then moved to Amoco, who was more receptive. This deal certainly broadened BP’s role in North America, but elsewhere in the world, too. That merger was followed up a year later with the acquisition of Atlantic Richfield. The Exxon/Mobil Oil deal set the stage for Chevron’s acquisition of Texaco, who had been wounded by its battle with Pennzoil over the Getty Oil acquisition. Prior to that deal, Chevron had acquired Rutherford-Moran Oil Corp. for its Indonesia natural gas assets, helping to strengthen Chevron’s Asia business. The Total/Petrofina deal added European refining assets, which were then complemented by the Elf Acquitane deal, which was engineered by the French government.

In light of the rationale that was supposedly driving the 1990s mergers, one might question, given the utterances of BP CEO Robert Dudley following the oil price crash of 2014 that his company was preparing for “lower for longer” oil prices, why it took over five years for the merger wave to start? Of course, that ignores the disastrous 2019 acquisition battle between Occidental Petroleum and Chevron Corporation to buy Anadarko Petroleum – a deal that was ill-timed, ill-financed and has jeopardized the financial health of Occidental.

The reality for oil company managers was that North America was becoming a wasteland of E&P opportunities, and the future dictated a more international focus, necessitating increased scale for all aspects of the business

The oil industry's long journey from the oil price crash of 1986 to Restructuring 1.0 was marked by episodes of small oil price rallies and busts. The reality for oil company managers was that North America was becoming a wasteland of E&P opportunities, and the future dictated a more international focus, necessitating increased scale for all aspects of the business. The final push for restructuring was the debacle of 1997, when everyone missed the bursting of the Asian economic bubble. The disastrous lifting of OPEC's production just as demand growth hit a wall led to a surplus of oil that needed to be worked down before oil prices could stabilize. In reality, the supply/demand imbalance corrected much faster than anyone anticipated, partly helped by China's gearing up the 2008 Olympics. That reality shift was unseen by the industry, investors or the media. The epitome of missing a market shift was the March 6-12, 1999, cover of *The Economist* magazine, titled: 'Drowning in oil'.

Exhibit 11. The Irony Of Mistiming The Oil Market

Source: ***The Economist***

<u>**Oil Industry Restructuring 2.0**</u>

Does the oil and gas industry consolidation currently underway measure up to the significant restructuring of the industry that began in 1998? We know history does not repeat, but it has similarities

In our estimation, the Chevron-Noble Energy deal comes closest to following the model of the industry deals executed during the late 1990s

(rhymes). In our estimation, the Chevron-Noble Energy deal comes closest to following the model of the industry deals executed during the late 1990s. Not only does this deal consolidate the Permian Basin acreage of the tow companies giving Chevron greater scale, but it will allow the combined company to reduce costs and become more efficient in exploiting its expanded resource base. This deal also adds critical scale and supply diversification to Chevron in the international arena, which should enable it to improve its competitive position (via synergies) in the global oil business. Will an improved share valuation follow?

The other recent deal that comes close to the late-1990s template is the Cenovus-Husky deal

The other recent deal that comes close to the late-1990s template is the Cenovus-Husky deal. The combined company can process more of its own oil, reducing its dependence on the Western Canadian Select oil price for selling oil, which usually trades at about a $10 per barrel discount to WTI prices. The new company plans to use the additional cash flow from the improved economics and synergies to pay down debt, improving its balance sheet. Lastly, the merger is going to lead to significant cost cutting, as management has recently indicated it expects to reduce employment levels by 25%. We are not sure how that can actually happen, but we will accept the estimate. With all these improved characteristics, one would expect the company's market valuation to improve, which is a key objective of the combination.

If investors continue to shun oil and gas investments due to fear they are buying into a "sunset" industry, it will remain a struggle for energy companies, even with improved balance sheets and greater profitability on the horizon, to see their valuations improve dramatically

But what about the other three deals, which involve primarily smaller E&P producers. These mergers are fulfilling the objectives of Shale 3.0 – keep production flat, improve profitability and use any surplus cash to pay down debt or return it to shareholders. One would expect the market to reward those companies with improved valuations, but will any improvements be material? That likely depends more on the relative market position of oil and gas investments in the stock market, given the societal and governmental pressures to phase out fossil fuels from our energy slate. If investors continue to shun oil and gas investments due to fear they are buying into a "sunset" industry, it will remain a struggle for energy companies, even with improved balance sheets and greater profitability on the horizon, to see their valuations improve dramatically. This is the most significant differentiator when considering the impact oil industry mergers may have on company valuations in 2021 and thereafter, compared to the improvements experienced by oil companies after the 1998-2002 industry restructuring. That history was dominated by an oil demand boom driven by China's consumption growth that led to $100-plus per barrel oil prices.

Exhibit 12. Can The Profit Truck Ever Be Refilled?

Source: ***The Economist***

They fail to acknowledge the physics of fossil fuel energy versus that of renewable fuels

In light of current energy developments, the cartoon that illustrated the March 1999 article in *The Economist* may actually be more apropos today when considering the oil industry's current state. It is impossible to find any forecaster predicting that the oil business is a growth industry. While there is an active debate over when global oil demand may peak, it is on the horizon. The more aggressive scenarios for the transition from fossil fuels to renewables foresees a demand peak soon, to then be followed by a demand collapse. On the other hand, most forecasters see oil demand recovering from the current Covid-19 episode and peaking within the next decade, but then remaining on a plateau for years, before beginning a slow, but steady demand decline. Such an outlook upsets the "green energy" promoters who fail to realize the magnitude of the structural economic change they are clamoring for, given the maturity and intermittency of the technologies they are promoting. They fail to acknowledge the physics of fossil fuel energy versus that of renewable fuels.

At the time the "Drowning in oil" cover story was being written, crude oil prices were in the low-$12 per barrel range, never to revisit that level until the Covid-19 oil futures debacle on April 20, 2020

Just as *The Economist's* 1999 cover of the two roustabouts slathered with crude oil marked a bottom in oil prices for the industry, the magazine's 2013 cover predicting "The end of the Oil Age," may also prove inappropriately timed. At the time the "Drowning in oil" cover story was being written, crude oil prices were in the low-$12 per barrel range, never to revisit that level until the Covid-19 oil futures debacle on April 20, 2020, when the oil price actually went negative. That was 241 months later! In the interim, the oil industry has survived several mini-boom and bust episodes. The strength of the companies that emerged from Oil Industry Restructuring 1.0 has allowed them to survive the industry's challenging periods. Hopefully, Oil Industry Restructuring 2.0 will prove equally rewarding for the surviving company shareholders, as their managers navigate the next 20 years.

Exhibit 13. A Tombstone Erected Too Soon?

Source: *The Economist*

Strong companies will become stronger, more profitable and better stewards of capital

For green energy sponsors who perceive the rash of oil industry mergers as the "last gasp of a dying industry," they fail to realize that this rationalization of oil company cost-structures will enable them to survive a world of "lower for longer" oil prices. Strong companies will become stronger, more profitable and better stewards of capital, all skills that will be necessary to actually reach "The end of the Oil Age," whenever it may arrive.

A Downside To Wind Turbines – Scrapping Them Safely

The problem is what to do with them when their useful life ends, often about the same time as their subsidy payments?

Wind energy has made giant strides within the renewable energy space, and is being pushed to take on an even greater role in the future, especially for offshore wind. Wind turbines have grown in size, enabling them to harvest more power per installation than earlier turbine versions. The problem is what to do with them when their useful life ends, often about the same time as their subsidy payments? Many of us remember the idled wind turbines were covering the hills leading surrounding passes we drove when heading into California. They were constructed in the 1970s in response to the energy crisis of that era, but soon became useless.

Last year, a popular story on Facebook was that there were 14,000 abandoned wind turbines in California. *Politifact* decided to check out the story by talking with Paul Gipe, a former wind energy company executive and the author of several books about wind energy. He disputed the number, saying that he was the author of the figure that 14,000 wind turbines existed in California, but only 4,500 have been abandoned and around 500 are still standing.

The blades of wind turbines are made from fiberglass that cannot be recycled or repurposed

Wind farm developers are required to provide a plan for decommissioning of the turbines, and since most of them are installed on private land, landowners are likely to hold them to their commitments. But, the blades of wind turbines are made from fiberglass that cannot be recycled or repurposed. Fortunately, fiberglass is inert and considered nonhazardous when buried in landfills, which is what is happening.

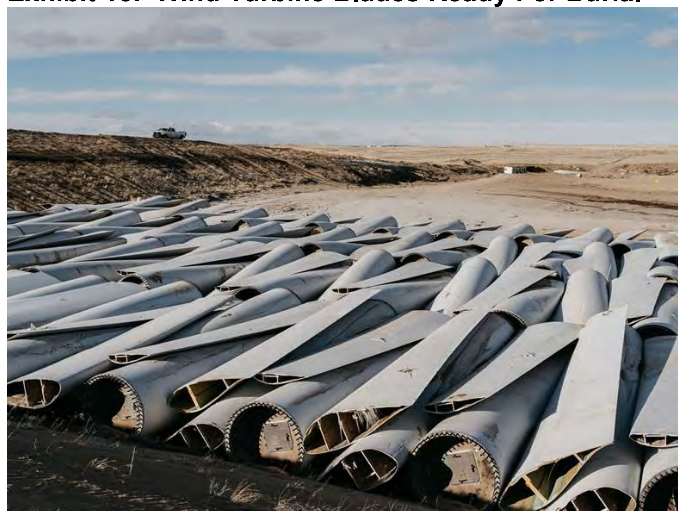
Exhibit 14. A Wyoming Landfill With Wind Turbine Blades

Source: Getty Images

They reported that 8,000 turbines per year are expected to be dismantled in the United States each year for at least the next four

A story about the burying of wind turbine blades in a landfill in Wyoming swept social media recently. The story and pictures proved accurate, based on an investigation by the investigative reporters at Snopes. Moreover, *Bloomberg Green*, the environmental news site for *Bloomberg News*, published an article not only documenting the story, but amplifying it. They reported that 8,000 turbines per year are expected to be dismantled in the United States each year for at least the next four, which will add to the landfill challenge. In the Wyoming landfill's case, it is only accepting wind turbine blades from three Wyoming wind farms.

Exhibit 15. Wind Turbine Blades Ready For Burial



Source: *Bloomberg Green*

In Wyoming, the 120-foot-long turbines are cut into three 40-foot lengths and the smaller sections are placed within the larger pieces

Due to their size – often as long as a 747 – the blades have to be cut into multiple pieces to facilitate their handling and burial. In Wyoming, the 120-foot-long turbines are cut into three 40-foot lengths and the smaller sections are placed within the larger pieces. Each turbine blade is then buried within a cell that measures a maximum of 44 cubic yards, or about the size of about three cement-mixer trucks. The effort involved, although usually paid for by the wind farm developer, is an economic and environmental cost of renewable energy generally ignored by the green energy activists.

Mr. Christian said the cost to abandon the 12,000 wind turbines currently operating in Texas could reach $2.3 billion

According to Wayne Christian, a commissioner of the Texas Railroad Commission, it costs about $200,000 to decommission a wind turbine, roughly 10 times the cost of abandoning an oil well, and over a 30-year shorter energy-producing life. He also points out that contrary to Texas regulations, a wind farm developer does not have to provide financial assurance for cleaning up a site, either through posting a bond or a deposit to cover the decommissioning cost in the event the developer fails to remove the turbine. That means state taxpayers may be on the hook for the clean-up cost, as opposed energy producers who are subject to rules requiring them to provide financial assurances to cover the cost of plugging and abandoning oil and gas wells. Mr. Christian said the cost to abandon the 12,000 wind turbines currently operating in Texas could reach $2.3 billion.

The Wyoming wind farms being dismantled are from 1990, or the start of the recent wind energy push. In the future, as more wind farms are abandoned, disposal of turbine blades will become an escalating cost, especially since wind turbine lives are a fraction of the life of a fossil fuel power plant, while also only producing power intermittently.

Fasten Your Seatbelt – Here Are Your Future Airplanes

Hydrogen – the new wonder fuel of the future – is being considered as a solution to the airline industry's CO_2 emissions challenge. Since hydrogen, when consumed, only emits water vapor, it is the cleanest fuel, assuming its technological challenges and economic hurdles can be overcome.

The problem is that planes will need up to four times the volume of kerosene to remain airborne

For all its environmental advantages, hydrogen is not an easy fuel to deal with. Compared to kerosene, it has three times the energy density, which is a big advantage over batteries, and it only weighs a third as much. The problem is that planes will need up to four times the volume of kerosene to remain airborne. For air transportation, space is notoriously scarce, and thus precious on any aircraft.

Another challenge is that hydrogen is a so-called cryogenic fuel, meaning that to liquefy the gas, it must be cooled to minus 253 degrees Celsius (minus 423 degrees Fahrenheit). But to be used for propulsion, the fuel must be compressed under high pressure, which necessitates a double-walled, cylindrical or spherical tank, adding a challenge to the aircraft's design.

The company's plan is to have available a zero-emission plane by 2035

European plane manufacturer, Airbus, recently unveiled three concepts for its hydrogen planes of the future, acknowledging that these are only designs. The company's plan is to have available a zero-emission plane by 2035. But which design?

Exhibit 16. The Longest Hauling Hydrogen Airplane

Source: Airbus

It is unable to do long-haul or transcontinental flights

The first concept is a conventional-looking turbofan design, able to carry 120 to 200 passengers on routes of up to 3,700 kilometers (2,300 miles). This means it is unable to do long-haul or transcontinental flights. The concept aircraft is slightly smaller than the current base model A320neo, such as those operated by Lufthansa among others, but it achieves the same speed of over 800 kilometers (500 miles) per hour when operating on hydrogen.

The design is shown in Exhibit 16 (prior page). "In the aft part of the aircraft, behind the pressure bulkhead of the cabin, the hydrogen tank is located, and the nozzle on top of the stabilizer serves to let off gas in the case of a leak," explained Airbus Chief Technology Officer Grazia Vittadini at a recent presentation of the hydrogen-powered airplane designs.

Exhibit 17. A Turboprop Hydrogen Plane Concept

Source: Airbus

The plane can reach 600 kilometers (375 miles) per hour, making it about 20% faster than current turboprops

The second concept is a turboprop aircraft with propellers, taking up to a hundred passengers on short-haul routes. The plane can reach 600 kilometers (375 miles) per hour, making it about 20% faster than current turboprops. Both concepts feature modified gas turbines for propulsion, complemented by a hybrid electrical motor run by fuel cells.

Exhibit 18. A Flying Wing Hydrogen Plane Concept

Source: Airbus

It is a hydrogen-powered Blended Wing Body design

The third concept is more disruptive. It is a hydrogen-powered Blended Wing Body design. The wings and fuselage form one continuous aerodynamic body. This design is deemed the preferred one for future aircraft. According to Airbus' Ms. Vittadini, "The blended wing is aerodynamically the most advantageous model to integrate hydrogen tanks. But that doesn't mean that it is the ultimate solution for all other parameters." We have seen military versions of “flying wings,” but never a commercial aircraft with passengers.

Exhibit 19. The Dutch Flying V Hydrogen Concept Plane

Source: KLM

Some experts say commercial versions may not be available for 20 years, beyond the target date

KLM and the Delft University of Technology in the Netherlands have shown their version of the Blended Wing Body concept - the Flying V – as a result of their study of possible hydrogen-powered aircraft. We wonder when we will see the first prototypes of these concept planes? Some experts say commercial versions may not be available for 20 years, beyond the target date. However, Dragan Kozulovic, professor for flight propulsion at the Hamburg University for Applied Sciences, said, "The world is ready for it and Airbus has seized the opportunity." He expects the turboprop to be the first commercial version, but then the airline industry will need to deal with readying the fueling system – the manufacture, transporting, storing and fueling of hydrogen - at airports before the next phase can begin.

"These aircraft will be significantly better, but not emission free"

Because hydrogen is only sustainable if produced from "green" energy, - solar or wind power – Dr. Kozulovic objects to Airbus billing its concepts, called ZEROe, as being entirely "emission free." Even if no CO_2 is emitted, combusting hydrogen still produces water vapor, causing contrails in the skies that have a climate impact, as well as nitric oxide. "These aircraft will be significantly better, but not emission free," he explained. Hum. Will those emissions be acceptable under the Green New Deal?

Random Energy Observations Worthy Of Attention

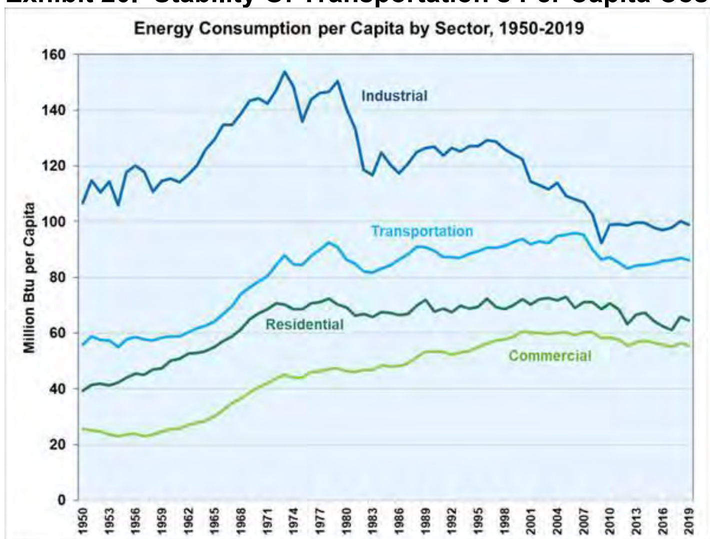
DOE Vehicle Technologies Office Fact of the Week October 26, 2020

Per Capital Transportation Sector Energy Consumption Has Been Relatively Flat Since 1974

On a per capita basis, the transportation sector energy consumption in 2019 was 86 million Btu, which is a 54% increase from 1950 and about the same level as in 1974

On a per capita basis, the transportation sector energy consumption in 2019 was 86 million Btu, which is a 54% increase from 1950 and about the same level as in 1974. The industrial sector, which had the highest energy consumption, decreased 7% from 1950 to 2019 and decreased 36% from its highest point in 1973. The residential and commercial sectors rose 64% and 116%, respectively, from 1950 to 2019.

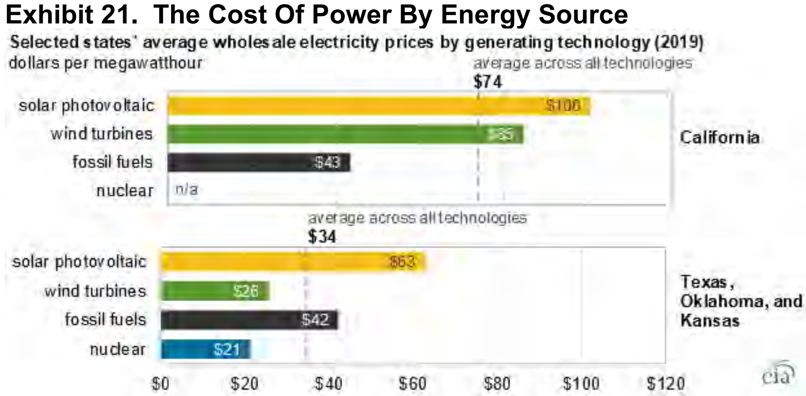
Exhibit 20. Stability Of Transportation's Per Capita Cost



Source: DOE

EIA's Today In Energy – October 9, 2020

Exhibit 21. The Cost Of Power By Energy Source



Source: EIA

Do subsidies and mandates have anything to do with California's high-cost of renewable energy compared to other states with large renewable energy output?

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