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

Summary:

The Rhyme Of Oil History Should Be Heard And Studied – Part 3

We continue our series on the history of the oil and gas and oilfield service industries through the boom of the 1970s and bust of the 1980s. In this article we focus on how the drilling business responded to the jump in oil prices and the subsequent decline of prices. The price trajectory impacted investment in energy and drove drilling activity, which suffered significantly in the 1980s and afterward. We study the trends in the drilling market, both onshore and offshore, and in international and domestic markets.

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Offshore Wind May Have More Problems Than Thought

The International Energy Agency released its latest World Energy Outlook that pointed out the huge potential offshore wind holds for the renewables sector. The problem is that two other reports are showing renewables cost declines are slowing, raising questions about their competitive status. The other report demonstrates that offshore wind farms have overstated their efficiency, reducing the rates of return on these projects.

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The Rhyme Of Oil History Should Be Heard And Studied – Part 3

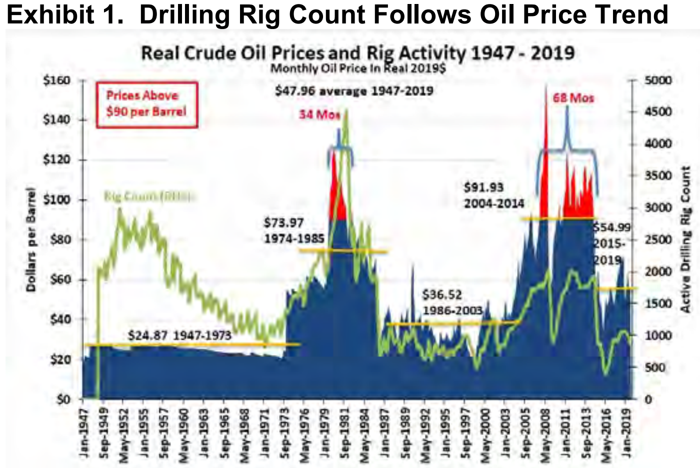
Figuring how much money companies will have to spend on new drilling and well completions next year is challenging

The Baker Hughes drilling rig count continues sliding lower as crude oil prices vacillate in a fairly tight range. There is much speculation on how quickly shale oil production will fall with the lower rig count. Although natural gas prices are climbing, it is primarily in response to a wave of early, cold weather that likely will produce the first storage draws of the upcoming winter season. Oil and gas companies have recently reported their third quarter financial results – some good and some less good – but the bottom line is that generating solid earnings and positive cash flow is harder than many have wanted to admit previously. Figuring how much money companies will have to spend on new drilling and well completions next year is challenging, given the shifting attitudes of investors, lenders and policy makers toward the unrestrained use of crude oil and natural gas.

If 2019 marks a watershed shift for the business, more dramatic corporate adjustments will be necessary

Industry executives, as well as others involved or merely interested in the future of hydrocarbons, wonder if the business is merely mired in a typical industry cycle, or is undergoing a more significant readjustment. The management playbook for an industry cycle is pretty well understood, needing a few tweaks, but not many major adjustments. On the other hand, if 2019 marks a watershed shift for the business, more dramatic corporate adjustments will be necessary. Our goal in writing this series of articles examining the industry's history during the 1970s oil boom and its subsequent bust in the 1980s and recovery in the 1990s, is to understand the similarities and differences of today's downturn compared to that history. That last major industry cycle needed a decade-long healing process extending well into the 1990s in order for the industry to ready for the opportunities and challenges of the 2000s. Are we looking at such an extended cycle this time? If so, what lessons does the past offer for guidance in navigating the future?

Exhibit 1. Drilling Rig Count Follows Oil Price Trend



Source: EIA, BEA, Baker Hughes, PPHB

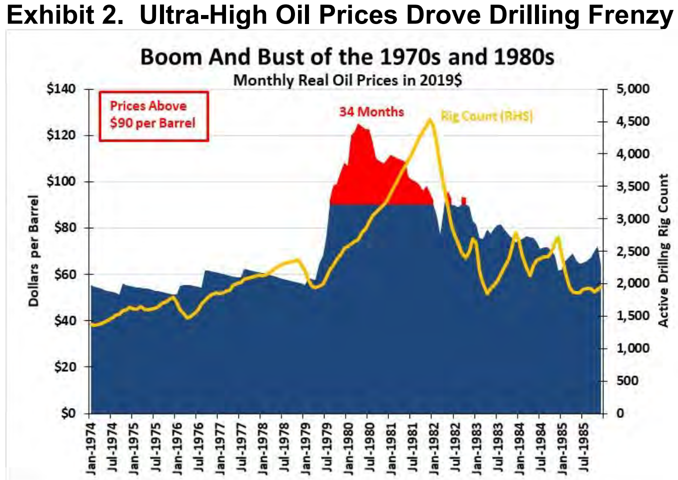
Based on his team's planning, the industry growth trends were so high that Mr. Clark questioned if they were on the "lunatic fringe"

The first two parts of this series have examined the broader history and development of the industry boom in the 1970s. We ended our last article after focusing extensively on the outlook for oilfield activity in the first half of the 1980s, as projected from the history and perspective of the 1970s boom. The president and chairman of Baker International Corporation, E. H. (Hubie) Clark, Jr., titled his talk to the IADC/PESA Marketing Seminar on August 14, 1980, "The '80s A Decade of Opportunity." That was an apt summary of the outlook for the industry as viewed from 1980. Based on his team's planning, the industry growth trends were so high that Mr. Clark questioned if they were on the "lunatic fringe." He was comfortable that they were not on that fringe.

In reality, the peak in industry activity was less than 18 months away from Mr. Clark's optimistic talk, but the real downfall for the industry came a few years later

As history demonstrated, Mr. Clark and his management team at Baker International were missing an understanding of critical trends unfolding that were altering the trajectory of the future energy landscape. This group of managers – highly respected within the business and among investors – were not alone in missing the seismic shifts underway. The optimism about the industry's future drove significant oil and gas, as well as oilfield service, investment and capital spending to expand the capacity of the business to meet anticipated energy needs. Unfortunately, the optimism was blind to the changes underway. In reality, the peak in industry activity was less than 18 months away from Mr. Clark's optimistic talk, but the real downfall for the industry came a few years later. Industry participants who survived the 1981-1983 rig collapse were "fooled" by the recovery experienced between 1983 and 1985. They were shocked when the "wheels came off" oil prices in 1985, and the industry, weakened by the earlier turmoil, was ill-prepared for the financial pressures suddenly crushing it. In some ways, the current industry environment is reminiscent of that mid-1980s collapse. That is why we focus so much on that past era, as we believe it does offer guidance for the challenging market of today.

Exhibit 2. Ultra-High Oil Prices Drove Drilling Frenzy



Source: EIA, BEA, Baker Hughes, PPHB

The value of the 55/45 stock/cash deal was nearly ten times SEDCO's $122 million in net income earned in its June 30, 1984 fiscal year

We are reminded of the story Carl Thorne, Chairman and CEO of ENSCO, used to tell about the 1980s downturn. He had been a senior executive with Dallas-based contract driller, SEDCO, when it was sold to the Paris-based Schlumberger, Ltd. (SLB-NYSE), the world's premier oilfield technology company. The deal was struck in September 1984 when Schlumberger, then headed by Jean Riboud, offered to buy SEDCO for slightly over $1 billion, a nearly 30% premium to the company's stock market value prior to the deal's announcement. The value of the 55/45 stock/cash deal was nearly ten times SEDCO's $122 million in net income earned in its June 30, 1984 fiscal year.

Mr. Thorne responded that he and his fellow managers were anticipating the downturn would last 10 years

The story involved Mr. Riboud visiting SEDCO after inking the deal. He and Mr. Thorne and a couple of other SEDCO executives were drinking coffee in the basement kitchen at the restored Cumberland Hill School on the edge of Dallas and home to the drilling company. Mr. Riboud questioned Mr. Thorne about his outlook for the oil and gas business, after proffering that Schlumberger's economists were calling for a recovery in 1985. Mr. Thorne responded that he and his fellow managers were anticipating the downturn would last 10 years, and was why they had undertaken to lock up their drilling rigs into long-term contracts with major oil companies, most likely to continue to drill, or at least pay their bills, even if oil prices fell.

On the other end of the spectrum were contractors who believed in striking long-term deals at "fair" dayrates, seeking to secure their revenue stream and offering better financial stability

The history of the contract drilling business, especially the offshore sector, was marked by differing philosophies about marketing rigs. Some contractors wanted their fleet to have short-term contracts so they would be frequently re-contracting rigs into what they anticipated to be a rising demand with rising dayrates. On the other end of the spectrum were contractors who believed in striking long-term deals at "fair" dayrates, seeking to secure their revenue stream and offering better financial stability. They acknowledged that they were often giving up the potential to earn more, but enjoyed the ability to always sleep well at night. Of course, there were companies that mixed the two pricing strategies, seeking a blend to capture some of the rising dayrates, but being assured of much of their income stream.

SEDCO, which started as a small land driller in Texas, had grown and was operating a large fleet of land drilling rigs in the Middle East, as well as commencing a fledgling offshore drilling business, starting with some jackup rigs. Over the years, with the help of talented engineers and rig architects, SEDCO developed leading-edge semisubmersible drilling rigs that were capable of working in deep water and harsh environments, especially the North Sea. The Clements family that had founded the Southeast Drilling Company was financially conservative. As they built new offshore drilling rigs, whose costs were escalating significantly, they would seek an initial contract that would repay about 2/3rds of the total rig cost in its initial work term. SEDCO was then willing to gamble on the market for subsequent contracts, feeling comfortable with the low debt associated with the rig. This approach to rig contracting gave SEDCO flexibility to bid lower if market conditions warranted in order to secure work. They also could push for premium rates based on the performance records of their rigs when the initial contract expired, especially if the offshore rig market was tight.

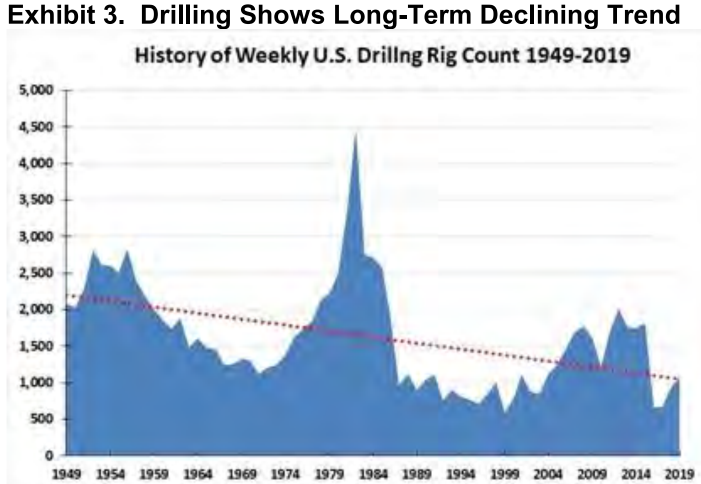
Always, the philosophy was for the initial contract to cover a substantial portion of the rig's construction cost, reducing SEDCO's financial risk

As the cost of drilling rigs spiraled higher, the initial contract term for rigs lengthened. What started out as two-year contracts grew to three years and then five. As rigs grew even more expensive toward the end of the 1970s boom, plus the desire of customers to want to push the technology limits for deepwater and harsh environment rigs, often demanding the new capability for dynamically-positioned rigs, along with rigs that were self-moving rather than needing to be towed between locations, contract terms stretched to seven and, eventually, ten years. Always, the philosophy was for the initial contract to cover a substantial portion of the rig's construction cost, reducing SEDCO's financial risk. For the final series of rigs SEDCO built, they entered into ten-year partnerships with oil company clients, or groups of clients, who put up some of the money, reducing the amount of debt the contractor had to assume. Many of these rig partnerships were entered into in the early- to mid-1980s. They were "unbreakable" agreements, to which we can personally attest. It was this fleet contracting philosophy that gave the SEDCO management comfort that they could survive a decade-long downturn. Barely over two years after the deal, Schlumberger was forced to write-off nearly $800 million of goodwill from the $1 billion purchase of SEDCO.

The drilling rig count provides a quick measure of the health of the oil and gas industry

The drilling rig count provides a quick measure of the health of the oil and gas industry, much like the Dow Jones stock index reflects the health of the economy. Exhibit 3 shows the history of the U.S. drilling rig count from 1949 to early November 2019. We added a linear trendline, which shows how the number of drilling rigs active in

Exhibit 3. Drilling Shows Long-Term Declining Trend



Source: Baker Hughes, PPHB

the United States has been on a downward trend line almost throughout the modern history of the business. That trend reflects the impact of the incredible improvements in drilling technology that have happened over the past 70 years. Improved drill bits, downhole directional drilling tools and systems, top drives, synthetic drilling fluids, increased real-time drilling knowledge, and on and on, have enabled the industry to do more with fewer rigs.

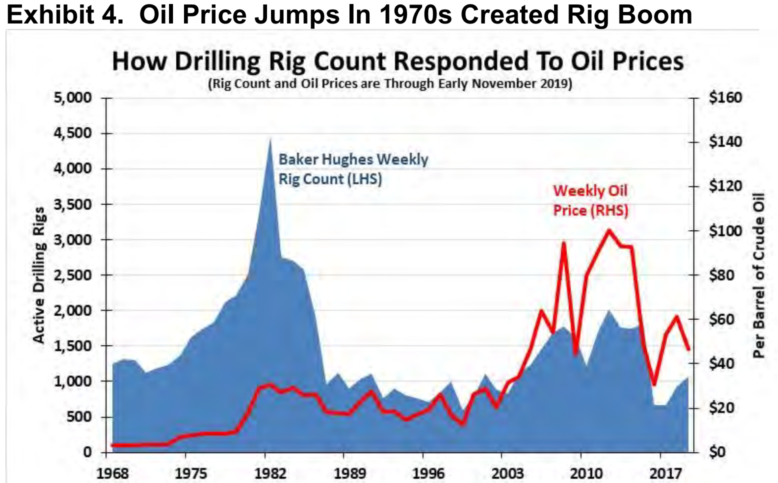
One also notices that during the 1960s, as well as the 1990s, the industry suffered through extended periods when the rig count was well below the trendline

When we examine the trend in active drilling rigs, we see high rig counts around 1950, in the 1970s and again during the shale boom of the early 2000s. Each of these peaks appear to have been anomalies above the trend line. One also notices that during the 1960s, as well as the 1990s, the industry suffered through extended periods when the rig count was well below the trendline. Does this pattern suggest that the drilling industry going forward may have to experience another extended period with activity rates under the historical trendline? There are many logical reasons why it won't: oil demand is substantially higher and continuing to grow; the world's oil market is much tighter than at almost any point in the past; and, the always persuasive argument – there are no more technology breakthroughs ahead. On the other hand, there are forces at work in the energy world that might reduce the amount of oil and gas the world will consume.

The high drilling rig counts in the late 1940s may have been a holdover from the incredible effort the oil industry undertook to help win World War II

The high drilling rig counts in the late 1940s may have been a holdover from the incredible effort the oil industry undertook to help win World War II. That was an era when oil prices were low, because the U.S. was the world's leading oil producer and supplier, and we were blessed with cheap oil, only to be surpassed in the future by cheaper oil from South America, the Middle East and Russia. Maybe, the key to future drilling activity will depend on international oil market trends.

Exhibit 4. Oil Price Jumps In 1970s Created Rig Boom



Source: EIA, Baker Hughes, PPHB

Each of those prices jumps helps explain the heady increase in drilling seen in the 1970s, with the 1979 jump producing the "lunatic fringe" forecasts Mr. Clark worried about

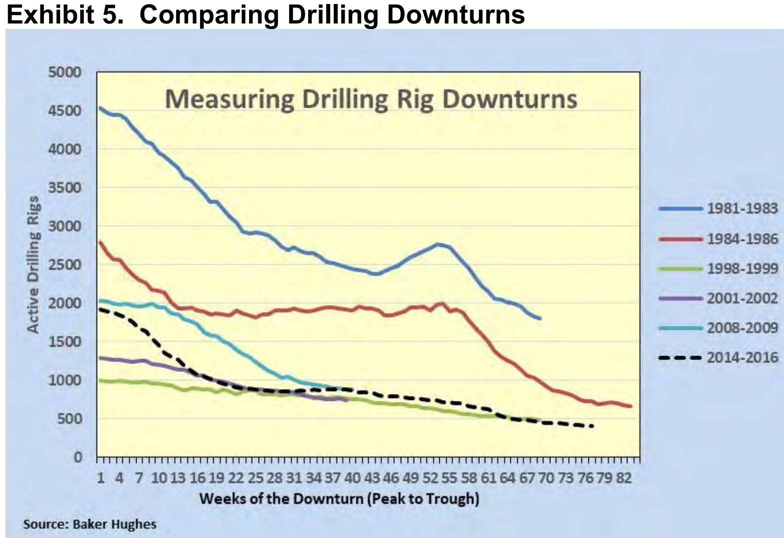
When we add the weekly oil price to the chart of weekly drilling rig counts, we find an interesting correlation. The rig count seems to closely follow the oil price. The oil price data is the price-of-the-day, so the early year low prices are not as low when translated into current dollar terms. What is noticeable about the early boom was the magnitude of the relative oil price increases in 1973 and 1979. Each of those prices jumps helps explain the heady increase in drilling seen in the 1970s, with the 1979 jump producing the "lunatic fringe" forecasts Mr. Clark worried about.

What we also see is that during the 1980s and 1990s, as the industry worked out of the excesses of the 1970s boom, the drilling rig count essentially matched the trend in weekly oil prices. That relationship was not obvious at the time to those in the industry. It is more clearly seen in retrospect.

When rig downturns are measured by the absolute number of drilling rigs laid down, 1981-1983 was the most significant

Given the changes in capabilities of drilling rigs over time, it might be interesting to look at rig downturns. We plotted downturns in drilling activity that lasted for an extended period. When rig downturns are measured by the absolute number of drilling rigs laid down, 1981-1983 was the most significant. What is more important is that absent the brief drilling upturn in late 1983 and early 1984, were we to combine the two downturns, we find that the industry shed roughly 3,800 rigs out of an active fleet at the start of 4,500!

Exhibit 5. Comparing Drilling Downturns

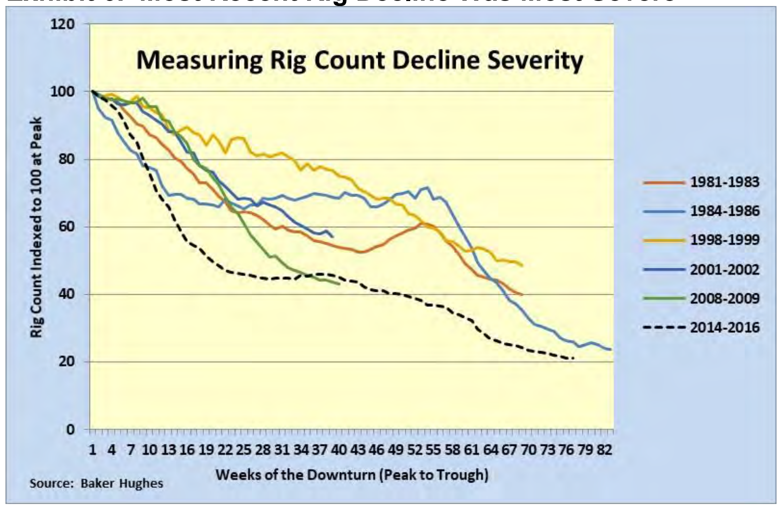


Source: Baker Hughes, PPHB

Even the smallest rig decline (1998-1999) resulted in nearly 500 rigs being dropped from the rolls. That means the 12-month long decline of 2018-2019, which has seen exploration and production companies letting 264 rigs go, or 24.4% of the working rig fleet in early November 2019, would barely register against the other rig declines. Exhibits 5 and 6 (next page) do not reflect the current rig downturn, as they were prepared and published in 2016.

What this analysis shows is that of all the rig declines, the 2014-2016 downturn has been the most significant

Exhibit 6. Most Recent Rig Decline Was Most Severe



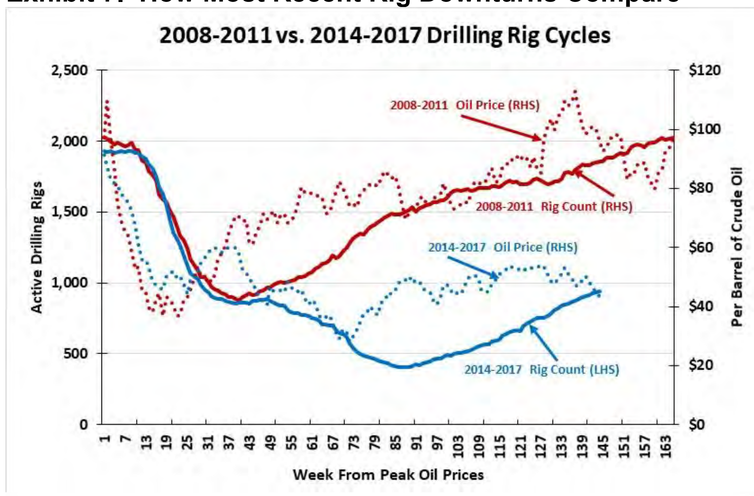
Source: Baker Hughes, PPHB

Looked at differently, the 2014-2016 rig downturn was the second fastest decline initially, but then it accelerated and became the sharpest decline of all the prior rig downturns. The rig count declines in Exhibit 6 were measured by indexing them to their peak starting points. What this analysis shows is that of all the rig declines, the 2014-2016 downturn has been the most significant. However, all the declines were fairly sharp for the first few months, but the 1998-1999 decline stands out because its fall moderates significantly compared to the others, which may reflect the more international characteristic of the oil market turmoil.

After about five months, all the rig count declines were about on par, except for the 2014-2016 decline. After nine months (40 weeks) both the 2014-2016 decline and that of 2008-2009 were at the same point. The latter decline ended and the rig count began rising as global crude oil prices rebounded following the easing of the financial crisis and ending of the 2009 recession.

The magnitudes of the rig declines may tell us something about the impact falling oil prices had on E&P company drilling economics. Exhibit 7 shows the absolute rig count movements compared to oil prices during the two most recent drilling downturns. The data shows that it takes nearly two months before the rig counts begin to fall once oil prices have dropped significantly. In both declines, the pace of the rig count declines was almost exactly the same until after nine months. In the 2008-2011 decline, oil prices were already in a strong recovery mode after nine months, which is what stopped, and ultimately reversed, that decline. In the more recent decline, the oil price recovery that began at about the same point as during 2008-2011 began to falter and headed lower. As oil prices in 2016 fell to a new low, the rig count decline slowed, but then accelerated and fell to its lowest point after approximately one and three-quarter years after the decline had commenced. One can see in this oil price/rig count decline pattern provided the rationale for Bob Dudley's, CEO of BP plc (BP-NYSE) mantra of "Lower for Longer."

Exhibit 7. How Most Recent Rig Downturns Compare

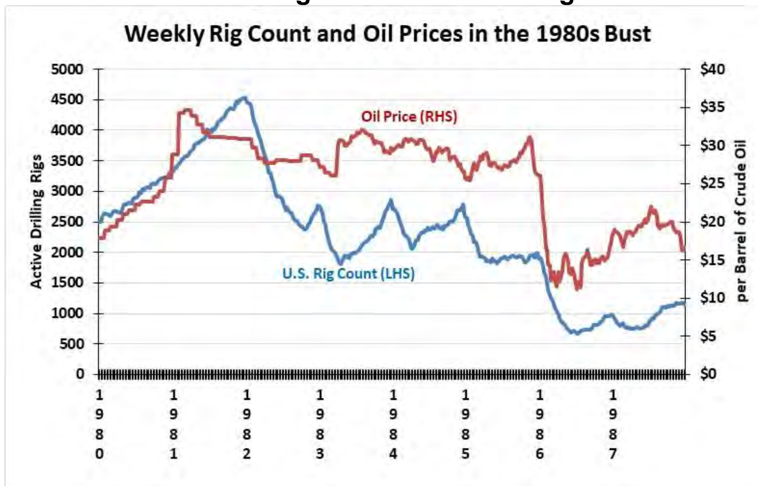


Source: EIA, Baker Hughes, PPHB

As oil prices fell day-by-day during 1985, ultimately reaching $10 per barrel, the question became when and how would Saudi Arabia produce cohesion about oil pricing policy to enable OPEC regain its market power?

An examination of oil prices and the weekly drilling rig count in the 1980s, shortly before it peaked and after the 1985 oil price collapse, showed a pattern much like that which the industry has recently experienced. The U.S. oil price peaked in March 1981 and then dropped steadily for the next two years. In early 1983, the oil price rose, but and then slowly eroded before rallying again in mid-1985. It was at that point that the Saudi Arabia's struggle to defend OPEC's official price, while conceding market share to its fellow organization members, forced the kingdom to take drastic action. It chose to ramp up its production, crushing the oil price. As oil prices fell day-by-day during 1985, ultimately reaching $10 per barrel, the question became when and how would Saudi Arabia produce cohesion about oil pricing policy to enable OPEC regain its market power? In the U.S., oil prices reached a low of around $13 per barrel before rallying back to the mid-$20s, but then dropping close to $15 per barrel in the 2nd half of 1987.

Exhibit 8. 1980s Drilling Bust Was Not Straightforward

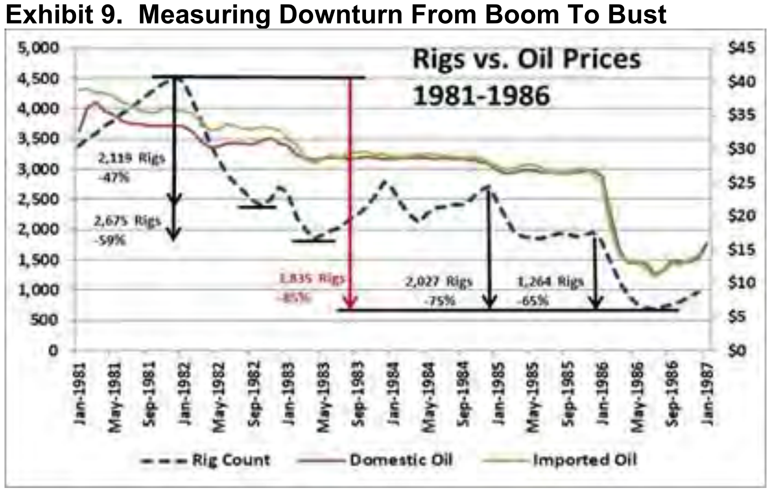


Source: EIA, Baker Hughes, PPHB

The reality dawned on people that high oil prices would bring on new supplies, leading to a topping out of energy share price advances

It was nearly six months after oil prices peaked that the rig count crested. As 1982 opened, the rig count was poised to collapse. People were beginning to realize that this was a possibility. As we remember it, an article in the *Wall Street Journal* highlighted the discovery of a new large oil field in Russia's Siberian region. Despite the reality that it would be years before this oil would hit the market, the article pointed to a number of new fields Russia was developing in this region. The reality dawned on people that high oil prices would bring on new supplies, leading to a topping out of energy share price advances, as investors turned against them. The prospect of a world oil "glut" seized the market's dynamics, making it hard for companies to make progress against a wave of worry about substantially lower oil prices and for an extended period of time.

Exhibit 9. Measuring Downturn From Boom To Bust



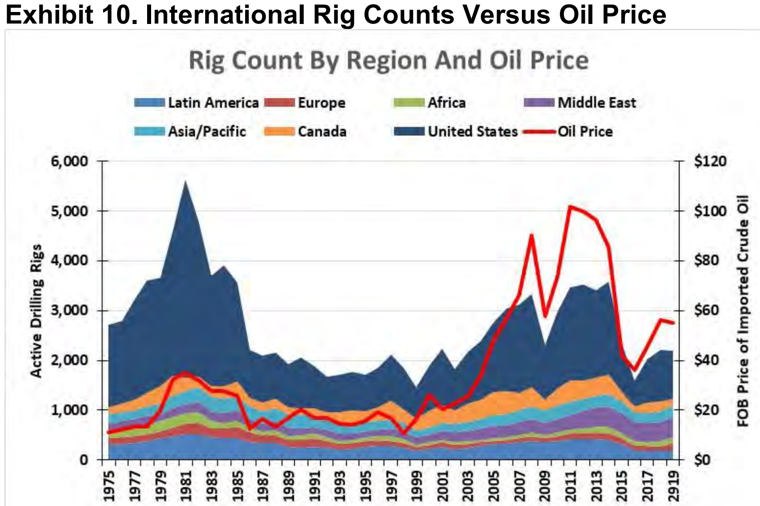
Source: EIA, Baker Hughes, PPHB

From peak to trough, the domestic drilling business saw the active rig count fall by 85%

After dropping nearly in half, the rig count bounced back briefly, only to resume falling. Exhibit 9 shows the magnitude of rig declines from the industry peak to its eventual bottom in summer 1986. From peak to trough, the domestic drilling business saw the active rig count fall by 85%. While it required four and a half years for this cycle to completely play out, there were periods when the rig count was rising in response to improved commodity prices and a belief that oil and gas price trajectories would lead to even higher future prices. The chart shows just how challenging market conditions were for the drilling business. The swings in the rig count would involve anywhere from 500 to 1,000 rigs. Each upturn generated optimism, only to see it crushed when the rig count fell.

A contributor to the rig count gains were increases in the offshore rig count, which we will deal with later. However, it is appropriate to examine how the international rig count fared compared to the U.S. rig count, during this time, as there were noticeable differences.

Exhibit 10. International Rig Counts Versus Oil Price

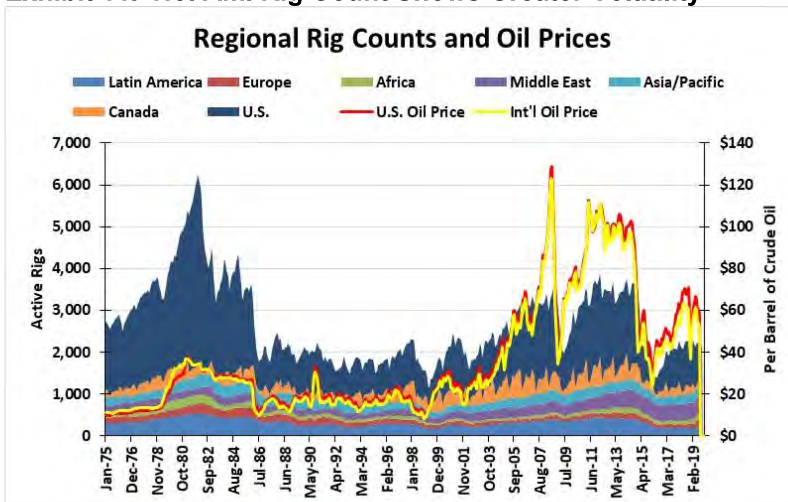


Source: Baker Hughes, EIA, PPHB

There was an intense drilling boom experienced in the North Sea (Europe) in the 1970s compared to much less active market recently

Exhibit 10 shows the rig count by broad international geographic areas, as well as for Canada and the United States. We have utilized the F.O.B. price for oil imported into the U.S. as the price marker. Besides the peak rig activity in North America in the 1970s and 2000s, one sees a similar response internationally. However, upon close examination, we see that almost every international area showed more activity in the 1970s and in the 2000s, also, but with fewer rigs in the latter period. That, as in North America, is probably related to drilling rig technology improvements. In some cases, it also reflects the passage of time. For example, there was an intense drilling boom experienced in the North Sea (Europe) in the 1970s compared to much less active market recently. A contrary pattern is seen in the Middle East, as Saudi Arabia ramped its drilling activity to sustain its high oil export volumes. Canada also showed more activity in the 2000s than in the 1970s, which we attribute to the increased role of Canadian natural gas in supplying the United States, as well as shale drilling technology.

Exhibit 11. No. Am. Rig Count Shows Greater Volatility



Source: Baker Hughes, EIA, PPHB

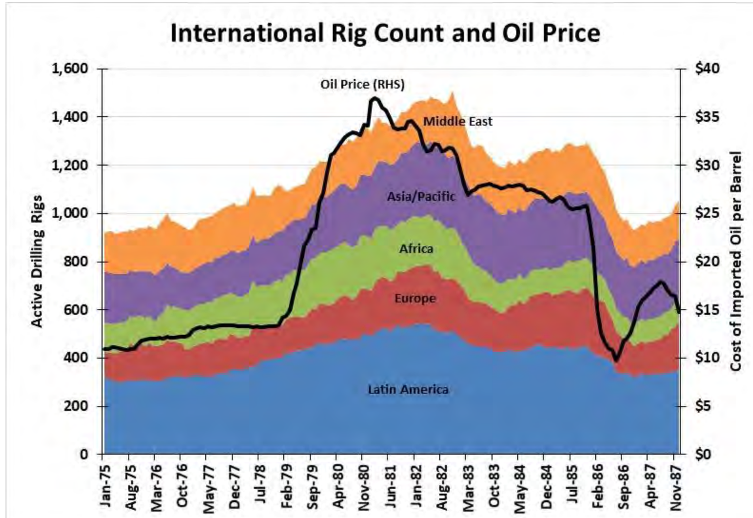
Outside of the United States, the most important international markets are the Middle East and Asia/Pacific

We see the annual patterns reinforced in the monthly data. We used both the first price for domestic oil paid by refiners and the average import oil price when tracking monthly drilling rigs in Exhibit 11. These two measures turned out to be more comparable, with a few exceptions, than we had anticipated. The most important conclusion we draw from Exhibit 11 is that outside of the United States, the most important international markets are the Middle East and Asia/Pacific. Latin America has had a very recent uptick in activity, but it remains unclear whether that increase will be sustained given the tumultuous political developments throughout that continent.

Different regions peaked at slightly different times, most notably with the Middle East peaking later

When we focus on the period prior to and immediately following the 1985 collapse in global oil prices, we find different drilling rig activity patterns internationally than observed in the United States. As seen in Exhibit 12, there was a slow growth in drilling activity in all regions that began in the second half of 1978 but peaked in 1982. Different regions peaked at slightly different times, most notably with the Middle East peaking later. Crude oil prices had peaked at the end of 1980, so the delayed response by drilling was a reflection of the lag-time necessary to wind down activity in the face of lower oil prices and reduced cash flows for E&P companies.

Exhibit 12. International Markets Tied Closer To Oil Prices



Source: Baker Hughes, EIA, PPHB

Following the 1982 peak, rig activity in all regions declined until late 1983, after which there was a rebound in activity that lasted until the collapse in oil prices in the second half of 1985. Crude oil prices had steadily declined from the 1980 peak to the second half of 1985 oil price collapse. We can see the start of positive increases in drilling activity in certain regions during the latter part of 1987 as oil prices started to rebound.

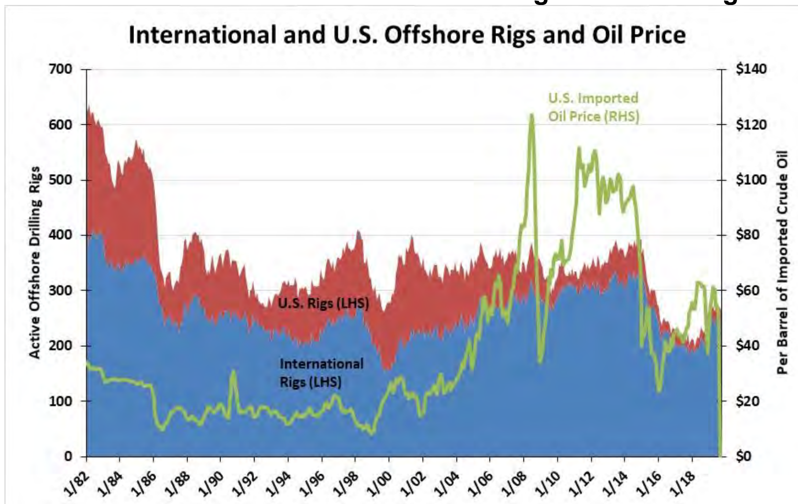
Because of the high cost of offshore exploration and development, this market segment activity has always been highly sensitive to oil prices

Turning to the offshore drilling segment, we find a much smaller industry and one that was growing rapidly as technology and economics were opening up many opportunities for E&P companies. Because of the high cost of offshore exploration and development, this market segment activity has always been highly sensitive to oil prices, oil price changes, and, importantly, expectations for future oil prices.

In the early 1980s, the U.S. offshore market included a number of rigs working off the East Coast and off California

Exhibit 13 shows a history since 1982 of the number of offshore working drilling rigs divided internationally and domestically. We have utilized the U.S. imported oil cost (price) as representative of world oil prices. What is amazing for those involved in the U.S. offshore market is how it has shrunk over time relative to the international market. We will point out that in the early 1980s, the U.S. offshore market included a number of rigs working off the East Coast and off California. There were also a few rigs working in Alaska, a market that still exists, but is considerably smaller than in earlier years. The East Coast and California markets are virtually non-existent today, and likely to remain that way given the anti-oil agendas of political leaders in these regions.

Exhibit 13. Domestic And International Rig Counts Changes



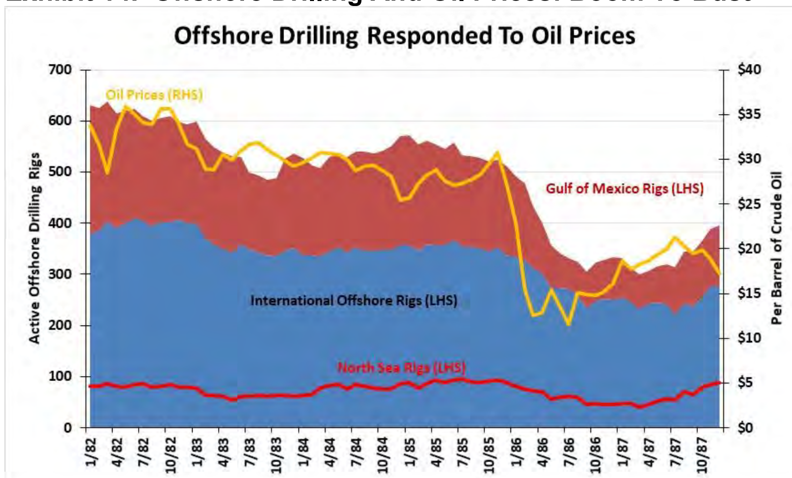
Source: Baker Hughes, EIA, PPHB

The message today for oilfield service companies is that if you are not involved in the international offshore market, you will struggle to generate revenues and profits when operating only in the domestic market. Hopefully that will change, but at the moment there is little precedent for today's offshore U.S. market other than during the early years of the offshore industry.

For much of the early 1980s, the total offshore drilling market was split about 1/3rd U.S. and 2/3rds international

That wasn't always the case, as we see when we look at the offshore drilling market of the 1980s. For much of the early 1980s, the total offshore drilling market was split about 1/3rd U.S. and 2/3rds international. What was going on then was important for the global oil industry. Note the North Sea rig count line, which represented about a quarter to a third of all international offshore drilling rigs up until the 1985 oil price collapse. That drilling effort proved to have a significant impact in changing the global oil industry's dynamics going forward. We would also point out the uptick in U.S. offshore drilling that began at the end of 1983 and continued until the oil price collapse killed industry capital spending.

Exhibit 14. Offshore Drilling And Oil Prices: Boom To Bust



Source: Baker Hughes, EIA, PPHB

The impact of so many new bidders drove average acreage bid prices toward minimal levels, but many more companies were able to secure significant offshore acreage positions

The U.S. drilling upturn, despite the continuing slide in oil prices, was a direct result of the change in U.S. government policy regarding offshore leasing. Prior to the 1983 Western Gulf of Mexico lease sale, the procedure for all offshore lease sales required two or more oil companies to nominate an offshore tract for inclusion in a sale. It was thought that this procedure would ensure competitive bidding on tracts that would provide the U.S. government with a fair price for the potential resources in the blocks. In May 1983, the government shifted its offshore leasing process to areawide. All the unleased acreage within a defined span of the Gulf of Mexico was put up for bid. This meant many more oil and gas companies could bid, assuming they qualified and paid their entry fee. The impact of so many new bidders drove average acreage bid prices toward minimal levels, but many more companies were able to secure significant offshore acreage positions.

Without having to encourage competition for leases, companies could secure acreage alone in order to test their newly developed theories

What areawide leasing did was transform the offshore E&P business. New offshore seismic technology had enabled exploration professionals to develop new theories about where oil and gas resources were deposited and how they might be discovered. Without having to encourage competition for leases, companies could secure acreage alone in order to test their newly developed theories, which many believed might be proprietary and give them a competitive advantage.

The effect on the offshore industry was similar to what the Indian lands experienced when the part of what became Oklahoma was opened to homesteaders, who were allowed to rush into the Unassigned Lands on April 22,1889. An estimated 50,000 settlers rushed in once the cannon boomed at noon, signaling the start of the land rush. These “boomers” rushed to stake out claims to land, only, in some cases, to find that “sooners” had entered the territory before the rush officially started and staked out claims. Towns such

The offshore free-for-all didn't quite match Oklahoma's history, but it certainly revitalized an oil and gas industry sector

The two areawide lease sales in 1983 resulted in the industry securing leases on four-to-five times more acreage than they acquired in the offshore sales of 1980-1982

as Norman, Oklahoma City and Guthrie sprang up overnight, and those homesteaders propelled Oklahoma's population growth, such that 18 years later the Indian Territories along with the Oklahoma Territory formed the State of Oklahoma, the 46th state of the United States. The offshore free-for-all didn't quite match Oklahoma's history, but it certainly revitalized an oil and gas industry sector that was sinking under the weight of sliding oil prices created by chaos within OPEC.

To grasp the significance of this development on the offshore petroleum industry, one only needs to look at what happened as a result of the two areawide lease sales held in 1983 compared to sales held earlier. As Exhibit 15 shows, the two areawide lease sales in 1983 resulted in the industry securing leases on four-to-five times more acreage than they acquired in the offshore sales of 1980-1982, which happened during the height of the industry boom and the peak in global oil prices. There was also a small Eastern Gulf of Mexico lease sale earlier in 1983 held under the old nomination-process that added 11 tracts and 58,120 acres to the industry's lease total for that year.

The industry's response to the areawide lease sales was beyond the wildest expectations. The sales, like all others, was held in a meeting room in the New Orleans Superdome and lasted for hours! It was broadcast over the radio enabling industry participants to marvel at the spectacle of the head of the Minerals Management Service having to yield to others in reading off the bid results on the hundreds of bids submitted to rest his voice. The impact lifted the sagging spirits of offshore industry participants.

Exhibit 15. Areawide Lease Sales Revived Offshore Drilling

		Sale	Planning	Tracts offerred		Tracts bid on		Tracts leased	
Year	Sale No.	Date	Area	Number	Acres	Number	Acres	Number	Acres
1980	A62	9/30	C	192	909,207	147	706,042	116	551,643
	62	11/17	W	81	456,720	74	420,058	67	383,323
				273	1,365,927	221	1,126,100	183	934,966
1981	A66	7/21	C&W	212	1,077,914	162	829,899	156	799,899
	66	10/20	C&E	209	1,081,364	107	532,064	102	508,301
				421	2,159,278	269	1,361,963	258	1,308,200
1982	67	2/9	C,W&E	234	1,219,847	137	695,765	115	590,265
	69(1)	11/17	C&W	144	732,570	67	339,999	56	281,213
				378	1,952,417	204	1,035,764	171	871,478
1983	72	5/25	C	7,050	37,867,762	656	3,249,199	623	3,089,872
	74	8/24	W	5,848	32,620,248	436	2,410,809	406	2,246,005
				12,898	70,488,010	1,092	5,660,008	1,029	5,335,877

Source: MMS, PPHB

Following the May 1983 sale, analysts and industry players began assessing how the oil and gas companies were going to test all the acreage acquired. Almost immediately drilling activity picked up, if for no other reason than for producers to make sure they secured

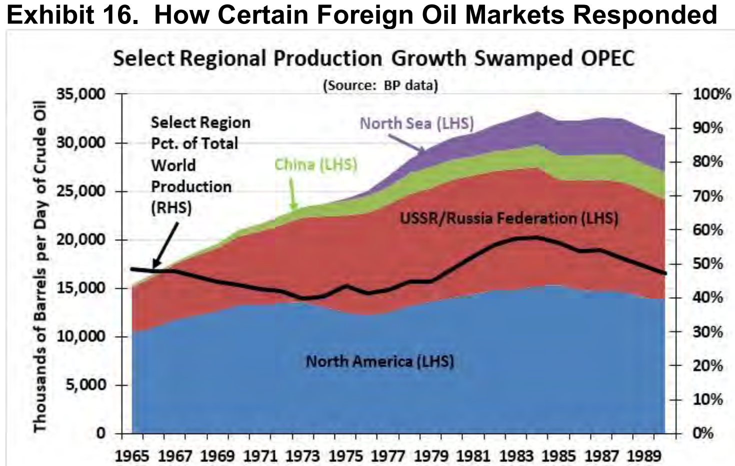
This was as close to nirvana as the industry had been since 1980, amidst the oil boom that was being driven by the fallout from the oil market turmoil due to the Iranian Revolution

rigs capable of drilling their new leases once the bids were approved and drilling permits issued. The August 1983 Western Gulf of Mexico lease sale results confirmed the impending boom for the Gulf of Mexico drilling business. This was as close to nirvana as the industry had been since 1980, amidst the oil boom that was being driven by the fallout from the oil market turmoil due to the Iranian Revolution. Little did people know how industry trends were soon to change and lives were about to be altered.

Thus, the decision came down to the incremental cost of drilling the well above the rig contract expense that would have had to be paid regardless

Across the Atlantic, the North Sea was in full swing, having been kicked off with the Ekofisk oil discovery in Norwegian waters in December 1969. The discovery, which came after the company and its partners had drilled 12 dry holes, among nearly 200 dry wells throughout the basin, propelled Norway into the ranks of international oil producers, a development with significant long-term implications for the global oil market. An interesting historical note comes from our conversation in 1972 with Phillips Petroleum geologist Max Melli. He was the man who had to convince the Board of Directors of Phillips to drill the 13th wildcat well, which discovered Ekofisk, after 12 straight dry holes. He was helped by the fact that Phillips had the ODECO's Ocean Viking drilling rig under long-term contract and the company's European management had been unsuccessful in finding someone willing to farm out the rig. Thus, the decision came down to the incremental cost of drilling the well above the rig contract expense that would have had to be paid regardless. As fate would have it, well Number 13 turned out to be very lucky for Phillips, which had been in a serious retrenchment effort, laying off 1,000 workers and suffering earnings hits from expensive dry holes. Phillips was not alone in the industry facing this fate, but for a smaller company, these were certainly dismal times. For OPEC, well Number 13 turned out to be not so lucky. It kicked off an exploration phase of one of the world's most significant offshore hydrocarbon basins. The impact can be seen in Exhibit 16.

Exhibit 16. How Certain Foreign Oil Markets Responded



Source: BP, PPHB

For the North Sea, the groundwork for its long-term future was set with the 1959 discovery of the giant Groningen gas field in the Netherlands

The impending shift in oil pricing power from the United States, and its Seven Sisters counterparts, was becoming evident as the decade of the 1970s opened. For the North Sea, the groundwork for its long-term future was set with the 1959 discovery of the giant Groningen gas field in the Netherlands. That field was estimated to contain 60 billion cubic meters (bcm) of natural gas, but since it contained a higher than normal nitrogen content, the energy output was not as high as with many other fields. As further delineation of the field occurred, its size swelled to 470 bcm in 1962 and 2,800 bcm in 1967. The greater significance is that the field's presence led geologists to reassess their views of the hydrocarbon potential for the Southern North Sea, and in turn, to examine the potential for the rest of the North Sea basin, especially the border line separating the UK and Norway sectors.

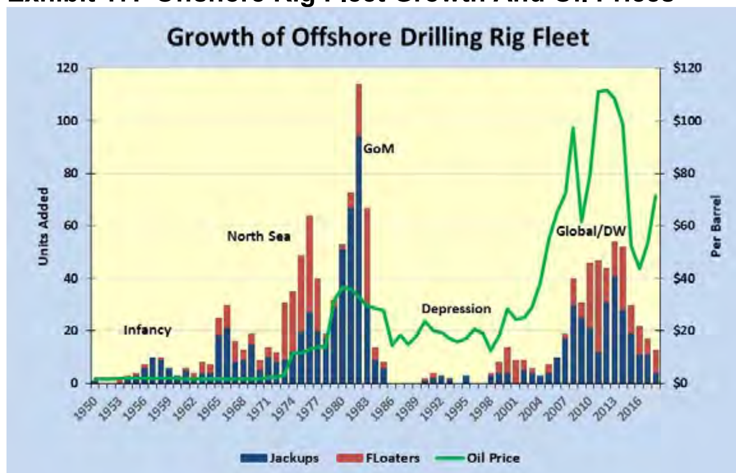
The North Sea emerged as a new oil supply source in the 1970s and grew in importance through the 1980s

What Exhibit 16 (prior page) shows is that the North Sea emerged as a new oil supply source in the 1970s and grew in importance through the 1980s. At the same time, the increase in the global oil price triggered by the Arab oil embargo in 1973 provided stimulus to regions such as China and Russia to lift their production. North American production also increased during the 1970s, with the United States leading output gains from Canada and Mexico. (We will explore the implications of high oil prices on emerging new supplies of crude oil that upset the global oil market balance in the next segment of this series.)

The North Sea rig boom barely ended before the huge fleet growth phase occurred, driven by the explosion in global oil prices in 1973 and 1979

More immediately, the emergence of the North Sea provided the impetus for expansion of the global offshore drilling rig fleet. In particular, the deeper waters and harsher operating environment of the North Sea drove the industry to build a large number of semisubmersible drilling rigs. These rigs are able to sink their substructures below the surface of the water to a depth that was subject to significantly less wave motion. As a result, these floating drilling rigs are highly stable allowing for safe drilling operations to occur. Exhibit 17 shows the annual offshore rig fleet expansion. The North Sea is marked and characterized by the large number of floating drilling rigs added. The North Sea rig boom barely ended before the huge fleet growth phase occurred, driven by the explosion in global oil prices in 1973 and 1979. That fleet expansion was marked by the orientation toward Gulf of Mexico drilling, which was in shallower water depths that was satisfied by jackup drilling rigs. As we showed in our last article, the use of tax-sheltered financing structures contributed nearly 7% to the rig fleet's growth during that period.

Exhibit 17. Offshore Rig Fleet Growth And Oil Prices



Source: Offshore Data Services, Barclay's, PPHB

In six of those years, no new offshore drilling rigs were added to the global fleet, a phenomenon that had not happened since 1951-1952

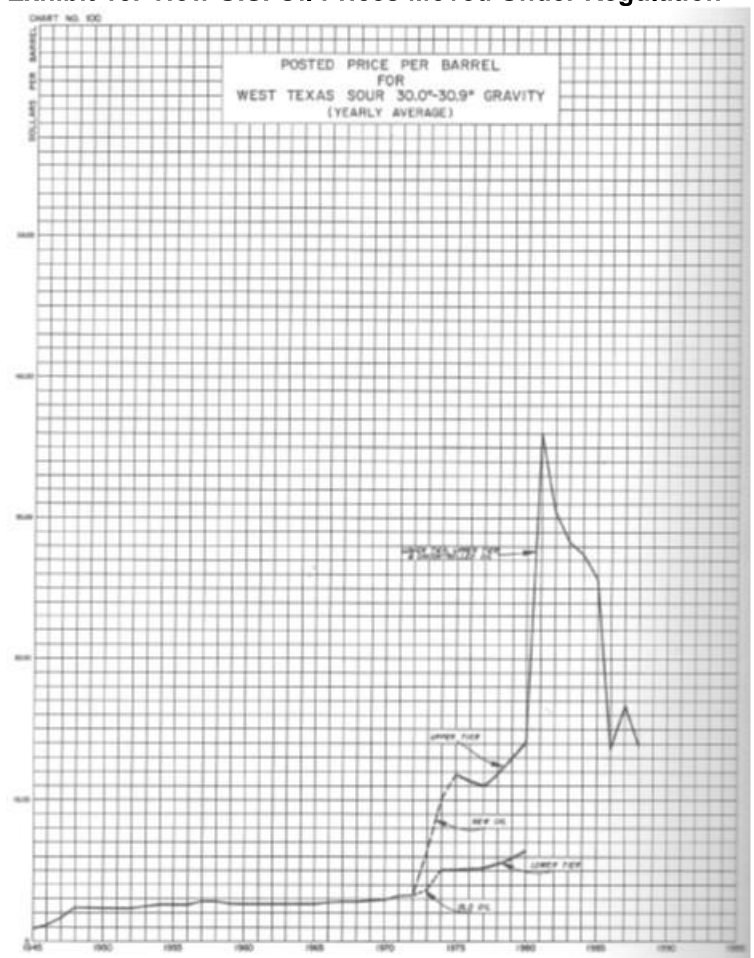
When oil prices peaked in 1982 and started down, the rig building boom ended. With its ending came the offshore industry's depression phase that lasted until nearly the end of the 2000s. From 1984 to 2007, the industry added few rigs, never reaching 20 new units in any one year. In six of those years, no new offshore drilling rigs were added to the global fleet, a phenomenon that had not happened since 1951-1952, at the very beginning of the offshore drilling industry. This depression period was marked by industry participants trying to survive.

The offshore fleet is now in the early stages of being rationalized by age and capability once again, as the industry becomes smaller and deals with the challenges of ultra-deep water as well as more remote and harsh environments

As the industry neared 2010, the recent success of deepwater exploration and development, coupled with extraordinarily high global crude oil prices, set off the latest offshore boom. This fleet construction phase was split fairly evenly between floaters and jackups. The former rigs were larger and more capable of operating in ultradeep waters and harsh environments, while the latter were often replacements for older, less capable jackups built in the prior boom. The offshore fleet is now in the early stages of being rationalized by age and capability once again, as the industry becomes smaller and deals with the challenges of ultra-deep water as well as more remote and harsh environments. This process will take years, much as the prior bust had to live through its depression.

One thing that is different with the current environment compared to the 1970s and 1980s is commodity prices. In the earlier era, there were a number of pricing issues that make linking activity shifts to changing prices challenging. To illustrate some of the challenges, we have included two scanned charts from volumes published in 1988 and 1989. The first chart (Exhibit 18, next page) shows the posted price per barrel for West Texas Sour 30.0°-30.9° gravity crude oil taken from the 45th edition of Twentieth Century Petroleum Statistics 1989, prepared and published by oil consultants DeGolyer & MacNaughton.

Exhibit 18. How U.S. Oil Prices Moved Under Regulation



Source: DeGolyer & MacNaughton

Starting in 1972, a dashed line moves sharply higher and is labeled "new oil," reflecting oil from newly drilled wells

The line shows the oil price history from 1945 through 1989. Starting in 1972, a dashed line moves sharply higher and is labeled "new oil," reflecting oil from newly drilled wells. This line continues to move higher until it peaks in 1975. At that point, a dotted line continues and declines to 1977 before rising again until 1980.

At the end of the oil price line in 1972, a dotted line extends and moves slowly higher until 1974 and is labeled "old oil." That old oil line remains flat through 1976 and then very slowly increases until 1980. This line is labeled "Lower Tier" oil.

In 1980, crude oil prices were decontrolled and Upper Tier and Lower Tier oil prices matched the Uncontrolled Oil price. Therefore, the line on the chart that starts in 1980 and spikes and peaks in 1981 and subsequently falls sharply, reflects market prices for U.S. oil. This era of U.S. oil price controls created significant turmoil in the industry as the rules were not clearly drawn and companies were

As one would expect, given so much confusion, it opened opportunities for fraud

forced to expend significant efforts in determining what classes of oil their wells were producing. As one would expect, given so much confusion, it opened opportunities for fraud. As some accountants were known to comment, they actually were the most successful oilmen in that era since they could turn "old" oil barrels into "new" oil barrels and generate significant profit increases without having to drill a new well.

Early in 1973, we went to Washington to meet with a government policy consulting firm and Congressional staff who were working on energy legislation. The consulting firm provided us with an early version of the price control legislation that Congress was working on drafting. It is important to remember that the world was not that far removed from an era of significant government price and allocation control over economic activity. That was a critical characteristic of the American economy during World War II, and to a lesser degree during the Korean War. Thus, the philosophical approach to dealing with spiking oil prices was government control.

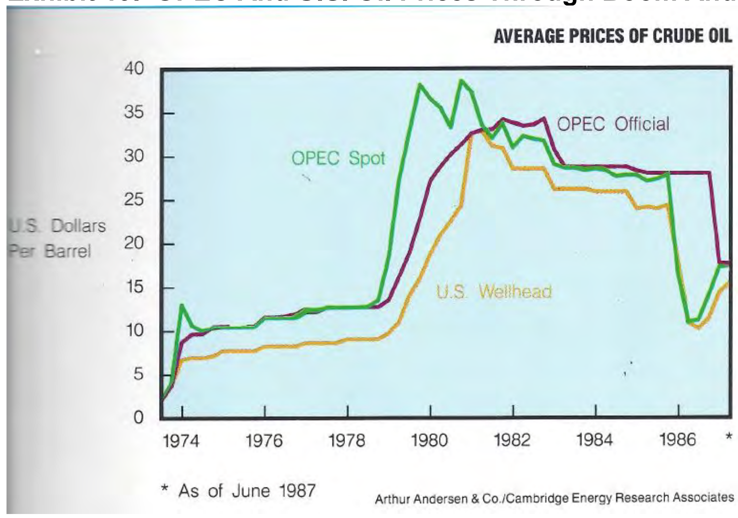
He realized that the creation of a tightly controlled "old oil" category, which represented most of Phillips's current output, was going to have a substantial impact on the earnings prospects for the company

The next day we were attending an investment meeting in Boston with president of Phillips Petroleum. As a representative of a large shareholder of Phillips, we had requested a private meeting with Bill Martin, who would be making the presentation. We showed him the draft legislation, which he had not seen, as his Washington office had yet to secure a copy. As the investor relations official was telling us that there wasn't much in the works legislatively that would impact Phillips' business, Mr. Martin began reacting to what he was reading. He realized that the creation of a tightly controlled "old oil" category, which represented most of Phillips's current output, was going to have a substantial impact on the earnings prospects for the company. This was when the company was in the midst of starting up its massive North Sea oil discovery, Ekofisk, which had not only changed the fortunes for the company, but would become an even more crucial component of the company's future earnings and cash flow prospects.

The chart shows how the U.S. used controls to keep domestic oil prices from rising to match market prices represented by OPEC Spot

The second chart (Exhibit 19) shows the interaction of world (OPEC) oil prices and U.S. prices. It came from the 1987-88 edition of World Oil Trends published by Arthur Andersen & Co. and Cambridge Energy Research Associates (CERA). The chart shows how the U.S. used controls to keep domestic oil prices from rising to match market prices represented by OPEC Spot. For most of 1974-1977, OPEC Spot matched the OPEC Official price. Starting in 1978, OPEC Spot surged sharply higher than OPEC's official price, but then began sliding as cheaper supplies found their way into the marketplace. There had been one market price retreat and rebound during 1979 and 1980, but then prices slid steadily lower, putting pressure on the official OPEC price. U.S. oil prices throughout this entire period remained below the global market price, until OPEC Spot caught up with it in 1985 amidst the oil price collapse engineered by Saudi Arabia. As the kingdom was able to ramp up production to teach its fellow OPEC members a lesson about cheating, it was unable to reach an agreement on what the new OPEC benchmark price would be until the latter part of 1986. That price agreement set the stage for the recovery of the oil industry.

Exhibit 19. OPEC And U.S. Oil Prices Through Boom And Bust



Source: Arthur Andersen, CERA

The turmoil of that earlier pre-war period was caused by the fallout from the oil industry's "gusher age," which saw spectacular discoveries such as Spindletop, the East Texas field, Sour Lake, Humble and Goose Creek, along with the Glenn Pool near Tulsa, Oklahoma, to name just a few

Industry participants, facing the chaos of the 1970s and 1980s, were learning on the job. There was virtually no one around who had managed through the oil business' wild 1920s and 1930s who could either take control or provide guidance for navigating through that environment. The turmoil of that earlier pre-war period was caused by the fallout from the oil industry's "gusher age," which saw spectacular discoveries such as Spindletop, the East Texas field, Sour Lake, Humble and Goose Creek, along with the Glenn Pool near Tulsa, Oklahoma, to name just a few of the significant fields of the first 30 years of the 20th Century. The arrival of new gushers led to periodic gluts that drove oil prices to extremely low levels. For example, in 1902, when Spindletop was pumping away, total production for the year exceeded 17 million barrels, at a time when the total production for Texas two years earlier was only 836,000 barrels. The result was that at one point, oil prices fell to 3-cents per barrel, below the price of water in some areas.

This market control mechanism became a key feature of the operation of the global oil industry

The governor of Texas, through the power of the Railroad Commission of Texas (RRC), also referred to as the Texas Railroad Commission, attempted to control production in an effort to stabilize prices. The federal government also exercised control at times. Eventually, the RRC gained control over oil production and set pro-rationing orders that limited the amount of oil a well could produce each month, which gradually stabilized oil prices. This market control mechanism became a key feature of the operation of the global oil industry.

In the Arthur Andersen/CERA report for 1987-1988, the authors made the following point about 1986.

One must not forget that the world oil industry is an industry in which, during much of its history, there has often been a manager or a management group – sometimes weak, sometimes strong

> "Last year, most market participants found the adjustment to an oil market without an effective management system to be difficult and disturbing. One must not forget that the world oil industry is an industry in which, during much of its history, there has often been a manager or a management group – sometimes weak, sometimes strong. The current management system is a device for relative stability and currently gives psychological support to the price and the system."

Reading the concluding paragraph of the report resonates for us as defining the challenge oil and gas industry managements, as well as investors and bankers, must confront today. The authors wrote:

> "Many companies still want to find the *one* forecast with which to guide their strategies into the 1990s. But a powerful lesson of the last decade and a half is the complexity of factors that shape the oil industry environment. Thus, companies seeking to make durable strategies need to test them against scenarios that capture the basic forces at work in the oil industry."

While many observers may think that renewable fuels are a new dynamic, their impact on oil demand was mentioned in the Arthur Andersen/CERA report 30 years ago

The forces that were shaping the oil industry in the late 1980s included psychological forces and government policies around the world, institutional forces such as the OPEC management system and the orientation of non-OPEC producers, and the physical factors of supply and demand. These are the same forces shaping the oil industry today. While many observers may think that renewable fuels are a new dynamic, their impact on oil demand was mentioned in the Arthur Andersen/CERA report 30 years ago. We actually have evidence of people paying attention to carbon emissions even earlier than that. This is further evidence of the value of studying the oil industry's past.

Offshore Wind May Have More Problems Than Thought

It shows the highest energy demand growth rate – 1.3% per year through 2040

The International Energy Agency (IEA) recently released its World Energy Outlook 2019 (WEO 19). The agency presented three scenarios - Current Policies, Stated Policies and Sustainable Development – assessing the future for energy supplies and carbon emissions. The Current Policies Scenario is essentially a "business as usual" case, which assumes nothing changes, in particular no improvements in energy efficiency, something that troubles us, as improvements happen naturally. As one would expect, it shows the highest energy demand growth rate – 1.3% per year through 2040. While that growth is well below the 2.3% increase experienced in

2018, it is still expected to strain all aspects of energy security. Moreover, this scenario is projected to continue to pump out large volumes of carbon emissions.

This is the IEA's attempt to show policymakers the consequences of their decisions rather than guessing how policy preferences might shift in the future

The Stated Policies Scenario used to be called the New Policies Scenario. The new name reflects the IEA's decision to base its forecast on only specific policy initiatives that have already been announced. This is the IEA's attempt to show policymakers the consequences of their decisions rather than guessing how policy preferences might shift in the future. We suspect the IEA no longer wants to speculate on future policy decisions only to be undercut by being wrong, which makes their projections of little value. It may also lend itself to being a hammer to pound on policymakers when their actions do not achieve meaningful carbon emission reductions.

The Sustainable Development Scenario is aspirational, as it embraces the Paris Agreement goals for limiting the rise in global temperatures to less than 2°C, and hopefully only 1.5°C. It also strives to deliver universal energy access and cleaner air. Achieving all these goals requires acknowledging that there are no simple or single solutions. To sharply cut emissions will depend on embracing an "all of the above" fuel matrix and technologies for efficient and cost-effective energy services. It would reduce carbon emissions the most of the three scenarios.

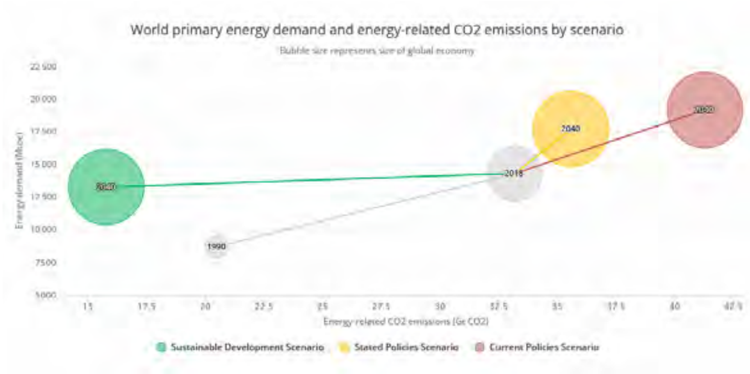
In the summary material we reviewed, there was no comment on future energy use in the Sustainable Development Scenario, but greater focus on the carbon emissions reduction. As mentioned above, energy demand rises 1.3% per year to 2040 in the Current Policies Scenario, but at a cost of substantial future carbon emissions.

The Stated Policies Scenario results in 1% per year energy demand growth to 2040

The Stated Policies Scenario results in 1% per year energy demand growth to 2040. In this scenario, expectations call for solar photovoltaics to supply more than half the growth, with natural gas meeting a third of the energy increase. Under this scenario, by the 2030s, oil demand flattens and coal use declines. The IEA expects many energy sectors will undergo rapid transformations, with electricity being the most impacted. Despite a positive outlook for renewables, they do not fully offset the energy demands from an expanding global economy and growing population. Carbon emissions growth does slow, but it falls well short of meeting the sustainability goal of limiting the global temperature increase to under 2°C.

Exhibit 20 shows CO_2 emissions projections for the three scenarios. Only the Sustainable Development Scenario shows a reduction in emissions, but we are unsure what sacrifices people must make for that to occur. When commenting on the scenarios, Dr. Fatah Birol, head of the IEA stated: "The world urgently needs to put a laser-like focus on bringing down global emissions. This calls for a grand coalition encompassing governments, investors, companies and everyone else who is committed to tackling climate change. Our Sustainable Development Scenario is tailor-made to help guide the members of such a coalition in their efforts to address the massive climate challenge that faces us all."

Exhibit 20. Carbon Emissions Under IEA Scenarios

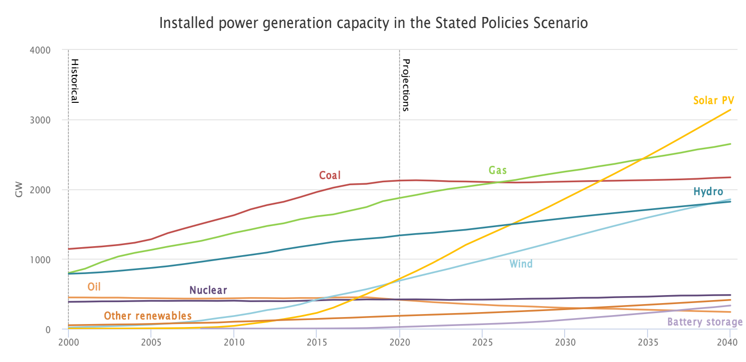


Source: IEA

The 1.2% annual rate of improvement achieved in 2018 is about half the rate seen since 2010, and well below the estimated 3% per year improvement needed to achieve the forecast

To achieve this reduced CO_2 goal, there needs to be a sharp pick-up in energy efficiency improvements. The problem is, according to the IEA, they are slowing. The 1.2% annual rate of improvement achieved in 2018 is about half the rate seen since 2010, and well below the estimated 3% per year improvement needed to achieve the forecast. Within this scenario, electricity overtakes oil by 2040. Wind and solar provide almost all the increases in electricity generation (Exhibit 21).

Exhibit 21. Renewables Should Show Strong Growth

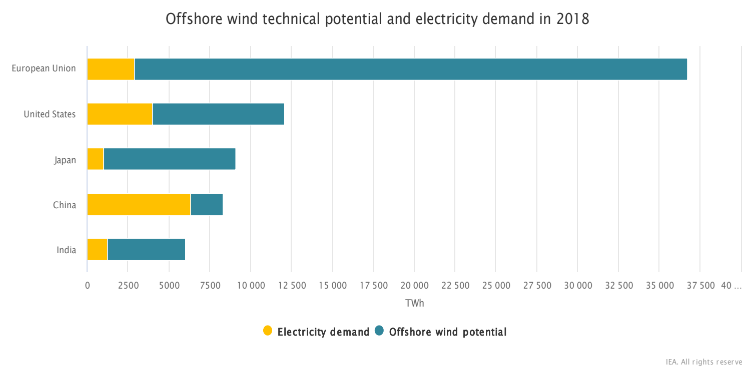


Source: IEA

The world's offshore is being opened up to greater wind power development

The IEA's focus on renewables was highlighted by a chart showing the potential of offshore wind along with electricity demand in 2018. The IEA says that given the cost reductions and experience gained in Europe's North Sea, the world's offshore is being opened up to greater wind power development. It means offshore wind has the technical potential to meet the world's electricity needs multiple times over. While acknowledging wind's intermittency, the IEA cites the fact that offshore wind offers substantially higher capacity than solar, and greater and more reliable power than onshore wind due to the use of ever-larger turbines to tap higher and more reliable wind currents, its development will be challenging.

Exhibit 22. Europe's Offshore Wind Bonanza



Source: IEA

The world's largest offshore wind company recently reported during its third quarter earnings call that it was downgrading the anticipated rates of return for several offshore wind projects in Europe and Taiwan

A twofold problem has recently emerged for offshore wind. First, Ørstad A/S (DOGEF-OTC), a Danish power company and the world's largest offshore wind company, recently reported during its third quarter earnings call that it was downgrading the anticipated rates of return for several offshore wind projects in Europe and Taiwan. The reduction is to 7-8% from 7.5-8.5%. It is due to reducing the expected efficiency of the projects to 48% from 50%. The changes were necessary after the company admitted that it had been underestimating the impact of wake and blockage effects on turbine performance.

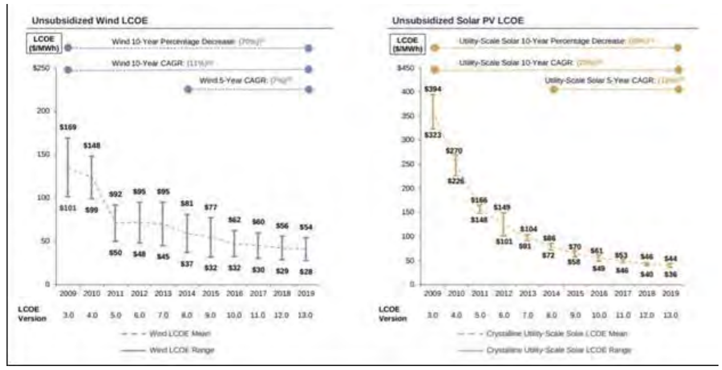
For wind, the cost decline for the last five years has been 7% per year, down from the 11% average rate of the last ten years

A second challenge for offshore wind comes from the conclusions of the latest Lazard study of levelized cost of energy (LCOE). The report showed that the decline rates for the cost of renewables, primarily solar and wind, were continuing, but at a much slower rate than in prior years. For wind, the cost decline for the last five years has been 7% per year, down from the 11% average rate of the last ten years. Solar has experienced a similar decline, falling to 13% from 20%.

In the Lazard study, the LCOE for offshore wind is more expensive than for a combined-cycle natural gas generator

What does that portend for the projections for renewables to cost less than conventional power sources, especially if backup power costs are included in the cost to run wind and solar projects? In the Lazard study, the LCOE for offshore wind is more expensive than for a combined-cycle natural gas generator. The Lazard study concludes that offshore wind, with an efficiency rating of 45-55%, has a LCOE of $115-$64 per megawatt-hour (MWh). That compares to a combined-cycle gas plant with 55%-70% efficiency and a LCOE of $$68-$44/MWh.

Exhibit 23. Renewables Growth Rates Have Slowed



Source: Lazard

The 25-year power purchase agreement (PPA) for the electricity calls for an all-in, fixed cost of $110.37 per megawatt-hour (MWh), which reportedly equates to a 2017 LCOE of $79.60/MWh

In Ørstad's third quarter earnings report, it reported that in July, New York State selected Sunrise Wind, a joint venture of Ørstad and Eversource, to build an 880 megawatt (MW) offshore wind farm. The 25-year power purchase agreement (PPA) for the electricity calls for an all-in, fixed cost of $110.37 per megawatt-hour (MWh), which reportedly equates to a 2017 LCOE of $79.60/MWh. The project is expected to be operational in 2024, assuming the partners reach a final investment decision soon. The difference between the 2024 PPA price and the 2017 LCOE is roughly 39%, or approximately a 5% per year increase. Given the admission that Ørstad has been overestimating the efficiency of its wind farms, we wonder whether such overestimation was factored into the economics, and subsequent pricing, for Sunrise? Clearly, there is time for the company to make adjustments or abandon the project, developments to keep an eye on.

The problem arises from the impact that arrays of wind turbines may have on overall efficiency compared to the efficiency of a stand-alone turbine

Ørstad management claimed that the efficiency reduction was not a company-specific issue, but rather an industry-wide one. That is a serious acknowledgement, as it suggests all the offshore wind projects are at risk of having overstated their efficiency ratings. The problem arises from the impact that arrays of wind turbines may have on overall efficiency compared to the efficiency of a stand-alone turbine, which is used in the calculation of the wind farm's efficiency. The degradation of the performance of neighboring turbines is a permanent condition, and the recognition of the impact is relatively new.

There are two wind turbine impacts: wake and blockage

There are two wind turbine impacts: wake and blockage. In wake, the impact comes from turbulent air reducing the output of turbines behind the subject turbine. Think of it as a wave crashing into a rock – water goes around it, while some goes over and some is repelled. Any rock behind the first one will not experience the same force.

In the case of blockage, the impact results from airflows slowing down as they approach an obstacle (wind turbine) and thus reduces the efficiency of the turbines on the periphery from what a stand-along turbine would produce.

These issues were highlighted in a 2018 paper authored by a team of engineers with DNV GL, an international accredited registrar and classification society based in Norway. The four engineers published a paper in *Energies* titled "Wind Farm Blockage and the Consequences of Neglecting Its Impact on Energy Production." The key conclusion of the paper was:

> "Field observations at three wind farms reveal significant wind speed reductions upstream of each project. The primary cause behind these reductions is very likely the presence of the wind farms themselves. Correspondingly, RANS solutions, which are in reasonable agreement with measurements, consistently exhibit wind-farm-scale and turbine-scale blockage slowing upstream flow as it approaches each wind farm. The magnitude and spatial reach of the measured and simulated slowdowns call into question widely used assumptions regarding the upstream influence of wind turbines. These findings, in turn, indicate that energy assessment procedures used throughout the wind energy community likely contain a material overprediction bias."

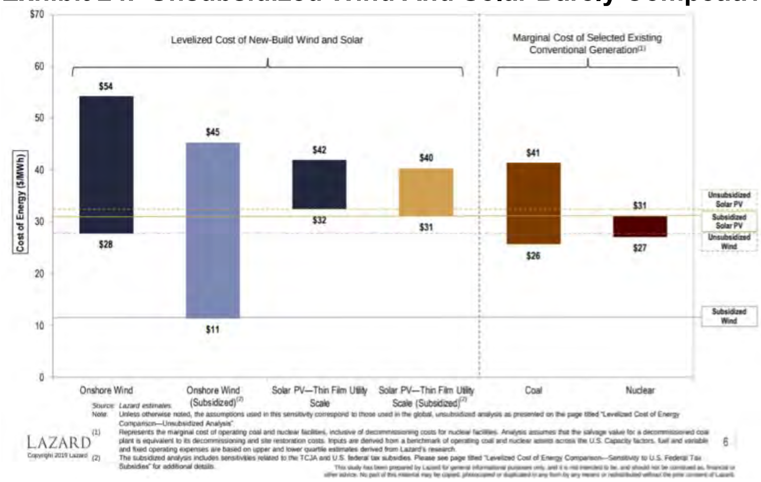
"These findings, in turn, indicate that energy assessment procedures used throughout the wind energy community likely contain a material overprediction bias"

According to the paper's lead author, "the standard approach does not account for the full extent of the blockage effect." As wind farms grow in number of turbines, and the size of turbines increases, there may be offsets to the blockage effect. More research will be necessary to assess this possibility.

Questions that still need to be answered include whether the efficiency reduction is only 2%? Could it be greater, and if so, what impact will that have on wind farm financial returns? Can the arrays of wind turbines be adjusted to reduce the blockage and wake effects, or possibly to even capitalize on them? The layout of wind turbine arrays is already subject to challenges for those projects being planned offshore Massachusetts. In those cases, the objectors include the fishing industry that needs greater clearances between turbines when pulling their nets, and the shipping industry that has discovered radar interference from wind turbines leaving vessels unclear where the turbines are actually located. Radar interference has also been raised by the military and the general aviation industry.

Questions that still need to be answered include whether the efficiency reduction is only 2%?

Exhibit 24. Unsubsidized Wind And Solar Barely Competitive



Source: Lazard

Absent subsidies, the low end of the LCOE for wind and solar are in line with marginal cost of coal and nuclear power plants

Another chart from the Lazard study, which we found interesting, compared the LCOE for new-build onshore wind and solar projects versus the marginal cost of coal and nuclear power plants. In the wind and solar examples, Lazard produced power cost estimates for plants receiving subsidies and those not receiving subsidies. Absent subsidies, the low end of the LCOE for wind and solar are in line with marginal cost of coal and nuclear power plants. With a $17/MWh subsidy for onshore wind, this fuel scores a huge win versus coal and nuclear.

With the slowing of the cost reductions for wind and solar, coupled with the new evidence of negative impacts on offshore wind projects, the smug assumption that green energy will prevail over fossil fuel, despite their intermittent nature may prove to be a less sure outcome. A lot more research still needs to be done, but certainly red flags have been raised.

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