ENERGY INVESTMENT BANKING

MUSINGS FROM THE OIL PATCH

August 23, 2016

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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

As Recovery Gains, Trajectory Becomes Critically Important

As long as that battle continues, and is shaped by weakening demand in China, the largest market within Asia, it is hard to see how oil prices can rise materially despite improving industry fundamentals

After retreating from the $50 a barrel threshold they had crossed in early June, oil prices have rebounded from their recent one-day settlement below $40 a barrel in early August. Oil prices are now being powered higher (into the upper-$40s a barrel) by the chatter that OPEC's leading producers and Russia may be willing to meet to establish a more stable oil price. What does this mean? For many, it would mark the end to the nearly two-year price war. Others remain unconvinced that the battle over market share, especially in Asia, the healthiest global oil market, is about to end anytime soon. Saudi Arabia continues to fine-tune its selling price to customers in Asia in a struggle to take market volumes away from its ferocious competitors – Iran and Russia. As long as that battle continues, and is shaped by weakening demand in China, the largest market within Asia, it is hard to see how oil prices can rise materially despite improving industry fundamentals. Might the oil exporters agree to a plan that freezes oil output? That could take the pressure off any scenario that would send oil prices back to the $30s a barrel. That would be good news, but likely not sufficient to send producers racing back to work.

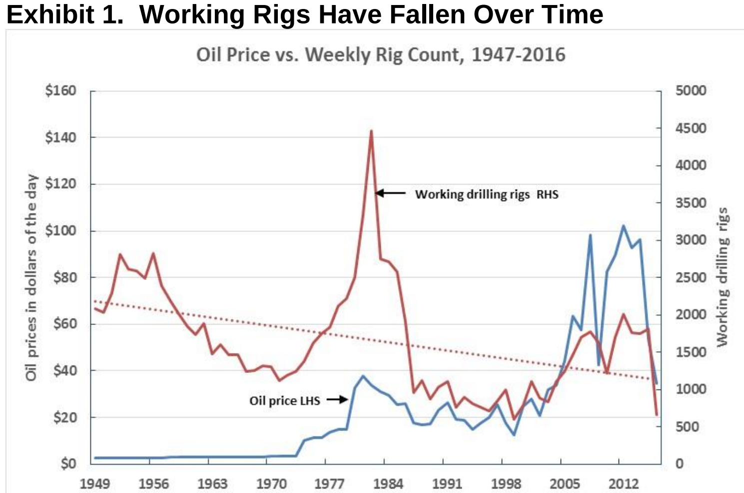
Is this the start of a sustained drilling rig recovery, or is it merely a blip

In response to rising oil prices, producers have begun to step up new well drilling activity having put 70 more drilling rigs to work over the past eight weeks, ending August 19th. Is this the start of a sustained drilling rig recovery, or is it merely a blip in response to the need for certain debt-loaded producers to boost their revenues and cash flows in response to higher oil prices? Obviously, there are some financially-strong producers who, because they bought properties during the worst of the industry downturn at extremely distressed prices insuring them ultra-low breakeven points, see more drilling as a normal profit-maximizing exercise. Without tracking every single well and which company is drilling them, it is impossible to know the answer to whether this is a healthy or survival driven recovery. What might be important in assessing the future of the oilfield service industry is to see how this nascent recovery is stacking up against previous ones.

First, over the entire period, there has been a downward trend in the number of drilling rigs needed to support our domestic production

Our starting point was examining the long-term history of active drilling rigs versus oil prices. We went back to the starting point for the Baker Hughes weekly drilling rig count. Since we don't have weekly oil prices, we spread the monthly oil price (dollars of the day) over the corresponding weeks of that month. Admittedly, when you plot data over nearly 70 years, it is hard to see some of the small movements in the trends. However, we can draw several conclusions. First, over the entire period, there has been a downward trend in the number of drilling rigs needed to support our domestic production. We have needed more rigs recently as production has grown, but even that number is being questioned by the sustainability of output despite the collapse in the rig count. This pattern stands out when you note the upward trend in crude oil prices that have soared above $100 a barrel in recent years. For purposes of this analysis we have used dollars of the day pricing for oil since those are the prices producers were reacting to when deciding about operating more or fewer drilling rigs.

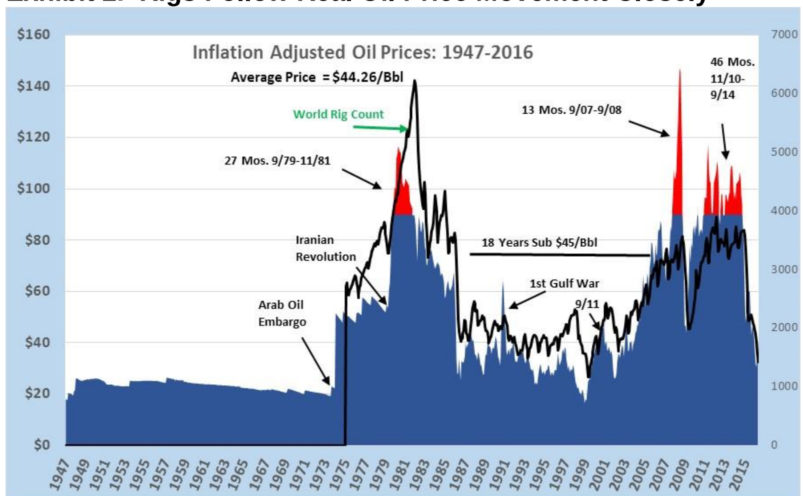
Exhibit 1. Working Rigs Have Fallen Over Time



Source: Baker Hughes, EIA, PPHB

The issue of whether oil prices and drilling rig activity were reacting to other factors is best shown in Exhibit 1 by the sharp decline in working rigs against a slowly rising oil price between 1949 and the early 1970s. Since that time, drilling rigs have closely followed real oil price trends. To demonstrate this close relationship, Exhibit 2 (page 3) shows oil prices for 1947-2016 against the world drilling rig count starting in 1975 (available data – this chart was generated for another use but is useful for this purpose). While the pattern in global drilling closely followed inflation-adjusted oil price movements, in recent years the count has declined despite high oil prices. This contrasts with the sharp rise in drilling rigs occasioned by the global oil price spikes in 1973 and 1978.

Exhibit 2. Rigs Follow Real Oil Price Movement Closely



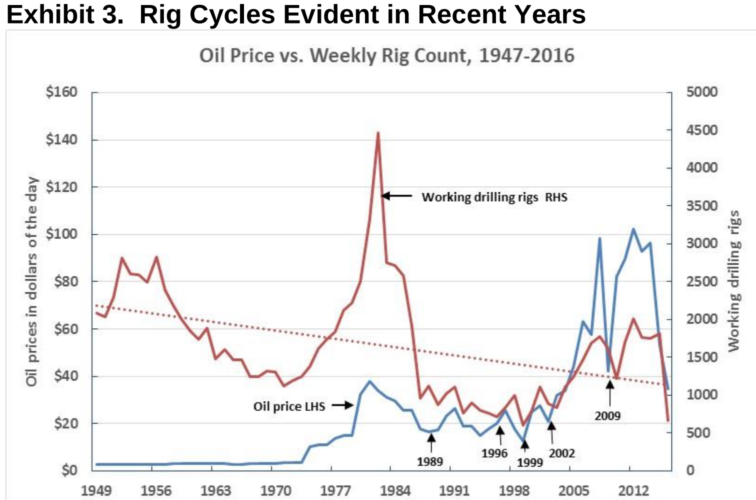
Source: Baker Hughes, WSJ, BLS, PPHB

The 1970s marked such a radical change in global oil market conditions

In examining the historical data for drilling rigs and oil prices, we eliminated the period prior to the dramatic oil price decline in the mid-1980s as offering little guidance about oilfield recoveries. That is because the 1970s marked such a radical change in global oil market conditions as oil pricing power shifted to OPEC producers and away from U.S. producers, who had exhausted their ability to supply domestic needs let alone export oil.

To perform our analysis of rig recovery cycles, we focused on industry conditions during five periods, marked by arrows in Exhibit 3, beginning with 1989.

Exhibit 3. Rig Cycles Evident in Recent Years



Source: Baker Hughes, EIA, PPHB

In 1989, the drilling rig business experienced its first recovery following the 1985 collapse

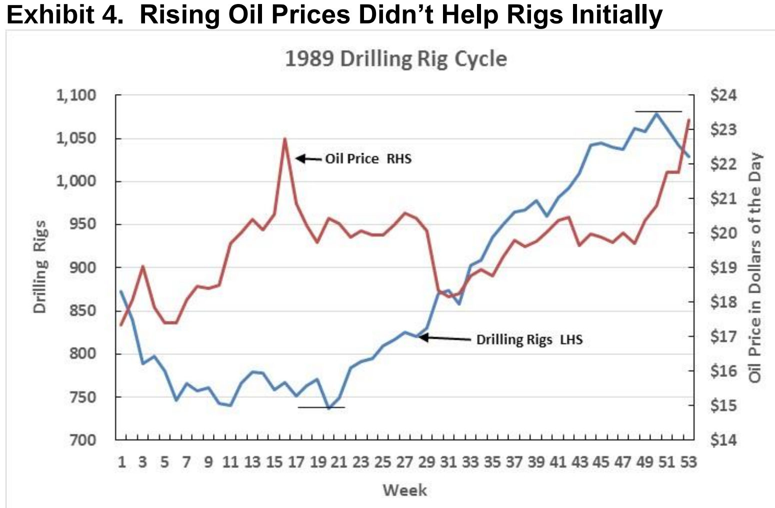
That price drop undercut the economics of new well drilling and led to the destruction of the global oil and oilfield service industries, and especially the contract drilling segment

Each drilling rig cycle was impacted by different industry dynamics, which makes drawing conclusions difficult about the one that offers the best template for how this rig count recovery is likely to progress.

In 1989, the drilling rig business experienced its first recovery following the 1985 collapse that followed the surge in non-OPEC oil output following the explosion in crude oil prices resulting from the 1973 Arab oil embargo, the 1978 Iranian revolution and the extended recession the industry experienced. As non-OPEC production surged in the early 1980s from places such as the North Sea, Alaska, West Africa, Mexico and South America, OPEC struggled to support the $32 per barrel oil price it had established as the market price. That price soon declined to $27 a barrel.

Saudi Arabia, OPEC's largest oil exporter played the role of market governor by cutting its production to attempt to hold up the informal OPEC price targets. As Saudi Arabia's output fell from 10 million to 3 million barrels a day, the country's oil minister, Sheik Zaki Yemani, decided to give up supporting the price because it allowed other OPEC members to cheat on their production quotas in order to seize greater revenues at the kingdom's expense. He ordered that output be stepped up, while letting global oil prices sink. The oil price struggle that spanned 1981-1986 saw oil prices fall from an average of $36.67 to $15.40. That price drop undercut the economics of new well drilling and led to the destruction of the global oil and oilfield service industries, and especially the contract drilling segment. Contractors had believed that the oil world had moved into a new era as a result of the jump in oil prices in the 1970s. They believed that the new era would be characterized by ever rising oil prices. Thus, the companies elected to mortgage their futures to build new drilling rigs to meet the anticipated demand of their customers, only to be wiped out by the OPEC oil price war.

Exhibit 4. Rising Oil Prices Didn't Help Rigs Initially



Source: Baker Hughes, EIA, PPHB

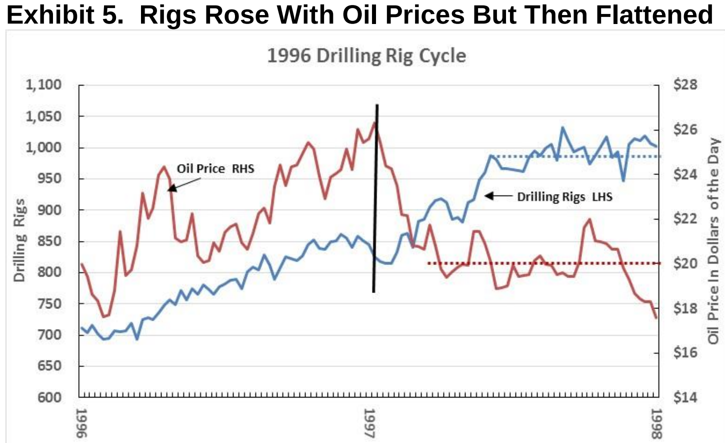
It went from 737 rigs working in week 20 to 1,079 in week 50, a 342-rig increase in a span of 30 weeks or a rise of 46%

At the end of 1988, oil prices had fallen below $14 a barrel. The rig count continued falling from late 1988 into 1989, and bottomed at 737 rigs during week 20. By then, oil prices were rising sharply until they peaked at $23 a barrel before falling back to the low $20s a barrel. After dipping to $18 a barrel, the oil price then climbed back above $23 a barrel by the end of 1989, helping the rig count to recover. It went from 737 rigs working in week 20 to 1,079 in week 50, a 342-rig increase in a span of 30 weeks or a rise of 46%.

As oil prices peaked at the start of 1997, the rig count continued rising as producers were convinced that oil prices would quickly rebound after the drop from $26 a barrel to $20

The 1996 drilling recovery followed a different pattern as rising oil prices during the first half of the year encouraged producers to consistently employ more rigs. Thus, the traditional response of drilling rigs following the direction of oil prices held throughout 1996. As oil prices peaked at the start of 1997, the rig count continued rising as producers were convinced that oil prices would quickly rebound after the drop from $26 a barrel to $20. This optimism was partially driven by Asian oil demand, which had grown sharply and prompted OPEC to increase its production to meet that demand. However, demand began falling due to the Asian currency problem caused by real estate speculation and bank lending issues in Southeast Asian countries, which undercut economic growth, causing panic in oil markets. Oil prices eventually stabilized, fluctuating between $20 and $22 a barrel before dropping to $18 by year-end 1997. The rig count also plateaued during the fall before dropping toward year-end.

Exhibit 5. Rigs Rose With Oil Prices But Then Flattened

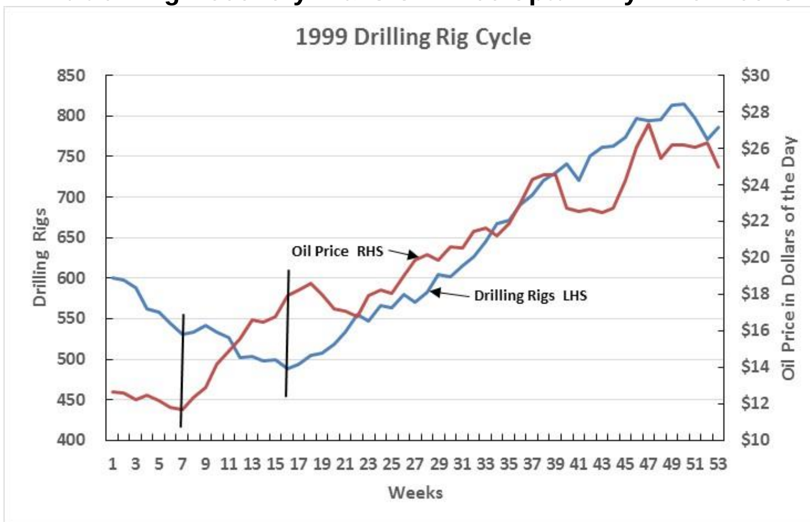


Source: Baker Hughes, EIA, PPHB

The two lines to the left in the chart in Exhibit 6 show that it took about nine weeks of rising oil prices before the rig count turned up

After falling to $12 a barrel at the onset of 1999, oil prices began a relentless climb to almost $28 a barrel by year-end. The rig count followed oil prices with a small lag throughout the year. It is interesting to see how quickly the drilling rig count responded to changes in oil price direction. The two lines to the left in the chart in Exhibit 6 (next page) show that it took about nine weeks of rising oil prices before the rig count turned up. That response time is not surprising given the time needed for producers to get organized, hire drilling rigs, move them to locations and start drilling.

Exhibit 6. Rig Recovery Trails Oil Price Upturn By Nine Weeks

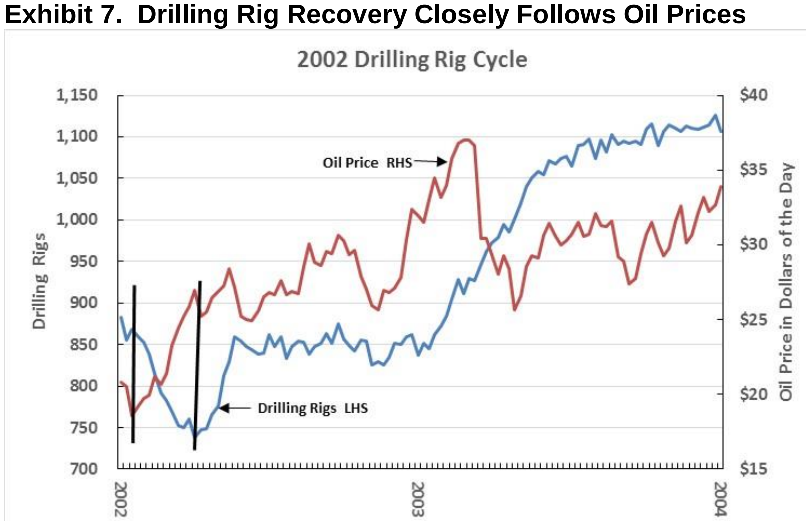


Source: Baker Hughes, EIA, PPHB

The surprise was that oil prices peaked at almost the exact same time the rig count turned up

The 2002 drilling rig cycle was another one in which rigs followed oil price movements with only a modest lag. Once again we looked at the upturn in oil prices that eventually caused the turnaround in the drilling rig count. Note the two black lines in Exhibit 7 marking oil price and drilling rig count lows. The surprise was that oil prices peaked at almost the exact same time the rig count turned up. Presumably, the volatility of oil prices during the balance of 2002, as they bounced between $25 and $30 a barrel, contributed to the rig count flattening after its initial surge. That pattern was essentially repeated in the fall of 2002 and into 2003. After dropping in early 2003, oil prices stabilized and traded between $25 and $33 a barrel while the rig count flattened after approaching 1,100 rigs.

Exhibit 7. Drilling Rig Recovery Closely Follows Oil Prices

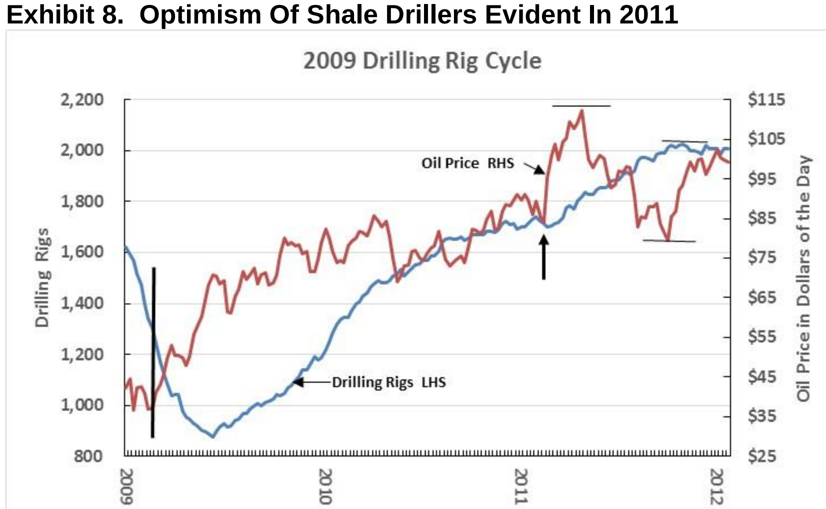


Source: Baker Hughes, EIA, PPHB

This rig count rise finally peaked at almost the exact same time the oil price pullback ended

The established pattern of oil prices leading the drilling rig count was also evident during the 2009 drilling rig cycle. This time, it took 16 weeks after oil prices bottomed and began rising before the rig count bottomed and turned up. When examining the chart (Exhibit 8), as the oil price advance flattened, the rate of increase in the working rig count also slowed. When oil prices peaked in early 2011, the rig count continued to climb at what appears to be a steady rate. This rig count rise finally peaked at almost the exact same time the oil price pullback ended. The sharp drop and subsequent oil price rebound seemed to have little impact on the direction of the rig count until it slowly began sliding late in the year.

Exhibit 8. Optimism Of Shale Drillers Evident In 2011

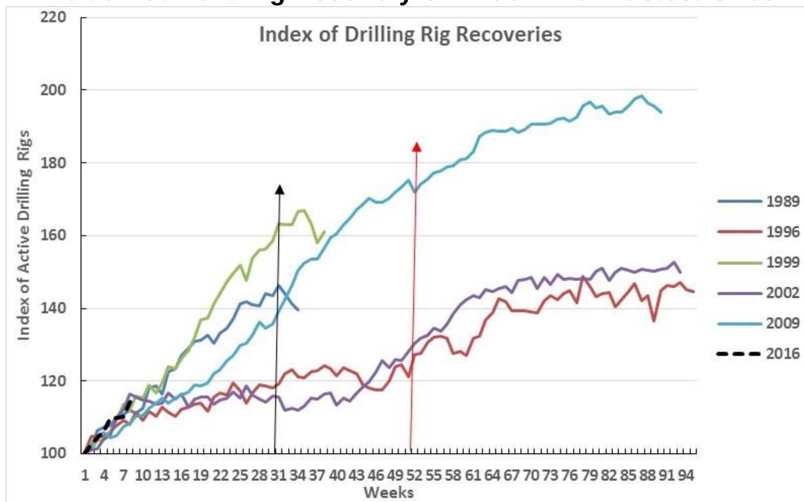


Source: Baker Hughes, EIA, PPHB

What this analysis showed was that the rig recoveries fell into two categories – rapid or slow

All of this color about the movement of oil prices and the drilling rig count during five significant industry recovery periods is helpful, but probably not as useful as a mechanical metric that would translate into a forecast for drilling activity over the rest of 2016 and in 2017. In order to assess where today's rig recovery, now up for seven straight weeks (through August 12), we indexed all the drilling rig recoveries so we could compare them better. What this analysis showed (Exhibit 9, next page) was that the rig recoveries fell into two categories – rapid or slow. The 1996 and 2002 recoveries proved to be the slowest. In contrast, the 1989, 1999 and 2009 recoveries proved to be the most robust, producing larger rig count gains. We also plotted the current drilling rig recovery, shown as the black dotted line. It shows that this recovery, while still in an early phase, is matching the three fastest recoveries. That has to be considered good news for oilfield service companies and their employees, especially those that have been laid off, but could receive recall notices in the future. The question is whether this fast pattern will continue.

Exhibit 9. Current Rig Recovery On Track With Fastest Ones



Source: Baker Hughes, PPHB

In Exhibit 9, you will notice two arrows – one (black) at the 30-week mark and the other (red) at the 52-week mark. The point of showing them is to calculate what the gains in past rig count recoveries would imply for the current rig count if it tracked those past recoveries exactly. The results of this analysis are shown in Exhibit 10.

Exhibit 10. Trying To Find Best Pattern To Repeat

	30-Week Increase		52-Week Increase		Past Rig Cycles		
Year	Index	Implied Rig Ct.	Index	Implied Rig Ct.	Starting Ct.	30-Week	52-Week
1989	143.55	604	NA	NA	737	1,061	
1996	118.18	498	127.27	536	693	819	882
1999	158.61	668	NA	NA	488	774	
2002	115.99	488	130.35	549	738	856	962
2009	135.73	571	171.92	724	876	1,189	1,506

Source: Baker Hughes, PPHB

That leaves the 2009 rig count cycle prediction as the more likely template for this rig count recovery

The current rig recovery started with the industry employing 421 drilling rigs. By applying the gains experienced in the past recoveries as of week 30 during their uptrends, we get implied rig counts that range from 488 to 668. As the rig count as of the week of August 12th was at 481 rigs, we could dismiss the 2002 30-week projection (488), and probably dismiss the 1996 prediction of 498 rigs as that implies only 17 more rigs going to work over the next 23 weeks. We also performed the same calculations for the 52-week time period, which only happened in three of the recovery periods analyzed. Again, given the number of remaining weeks in the recovery (45), it seems that the 1996 and 2002 projected implied rig counts are likely conservative at 536 and 549, respectively. That leaves the 2009 rig count cycle prediction as the more likely template for this rig count recovery.

If that template proves correct, then we could be looking at another 90 rigs added over the next 23 weeks. The 52-week target of around 724 rigs in June 2017 implies a gain of 243 rigs. What the

That latter point may really depend on how sustainable producers believe the well drilling and completion cost reductions of the past two years are

2009 rig cycle pattern suggests is that the rig count will grow slowly in the near future but then accelerate as we move into 2017. Whether that proves a likely trajectory depends on the future course for oil prices and how quickly higher prices both repair the damage to the industry and instill confidence in producers to resume activity. That latter point may really depend on how sustainable producers believe the well drilling and completion cost reductions of the past two years are. If they believe prices will rise soon, the pace of drilling could accelerate in an attempt to capture the lower prices.

Four of the five past cycles commenced with the rig count at substantially higher levels than this rig recovery

A potential criticism of our analysis is that every past drilling rig cycle started at different levels of rig activity. Therefore, it is possible that the percentage recovery rate reflected in those past cycles might have been impacted by their starting points. We listed in the far right-hand columns of Exhibit 10 the starting rig counts for each cycle, what level they reached in week 30 of their recovery, and their 52-week rig count number. Four of the five past cycles commenced with the rig count at substantially higher levels than this rig recovery. The 1999 rig cycle showed the closest starting-point comparison with 488 rigs versus the 2016's 421 rigs. If the starting point is important, then by following the 1999 rig cycle pattern, we might be looking at a U.S. drilling rig count around 670 at the end of 2016. That would imply a gain of about 190 rigs, or 100 rigs more than projected if the current rig recovery follows the 2009 rig cycle pattern. Because of the lower starting point for this cycle that is not a surprising conclusion.

What the next rig cycle may reflect is a return to exploration and production profitability at lower oil prices as a new discipline is embraced

Two last points to consider, if one wants to utilize the 2009 rig recovery pattern as a guide, are the influences of $100 a barrel oil and the emergence of the shale revolution. Both events were pointed to by industry participants saying that they reflected a new world for oil and gas. Maybe. What the next rig cycle may reflect is a return to exploration and production profitability at lower oil prices as a new discipline is embraced. Of course, the recovery will continue to depend on capital availability, but that is really a discussion about zero-interest rate monetary policies and their distortion of global energy economics. We will continue watching and cheering for the 2016 rig cycle recovery as it is currently on a pace that is faster than the most robust rig cycle recoveries in history, but we remain early in the recovery phase.

Canadians Learning The Cost Of Environmental Legislation

Some of the Canadian experience with green energy and its cost pre-date Mr. Trudeau's rise to power.

The love affair between United States President Barack Obama and Canada's Prime Minister Justin Trudeau, is largely based on their symbiotic view of climate change and the need to radically alter their respective economies to prevent the potential damage. Some of the Canadian experience with green energy and its cost pre-date Mr. Trudeau's rise to power. Much of the experience comes from power market machinations conducted in the province of Ontario.

The NDP's agenda was left of center and heavily focused on changing the province's natural resource based economy

The most recent Canadian green energy shock is occurring in the province of Alberta where the New Democratic Party (NDP), led by Premier Rachael Notley, gained political office a few months ahead of the national election that brought Mr. Trudeau into office. The NDP's agenda was left of center and heavily focused on changing the province's natural resource based economy, raising taxes and implementing a green energy agenda.

Alberta's economy is estimated to experience a 1.9% contraction in 2016 after shrinking by 4% in 2015

The oil industry downturn arrived shortly before the NDP assumed power and has slammed the province's economy while generating knock-on economic impact on the nation's economy. Alberta's economy is estimated to experience a 1.9% contraction in 2016 after shrinking by 4% in 2015, but the nation is expected to post a 1.5% gain in gross domestic production (GDP) this year after reaching only a 1.2% growth in 2015. The continuing global economic weakness may prove to be a further drag on Canada's national economy, although the rise in global oil prices may assist Alberta's economic recovery. Now, however, Alberta is facing a huge potential problem with the cost of its electricity that could further penalize future economic activity in the province.

The far-ranging climate policy, besides raising the carbon tax for the first time in eight years, also included a cap on oil sands emissions, a phasing out of coal-fired electricity generation and an emphasis on wind power

In late November 2015, Premier Notley announced that the government would raise the carbon tax in the province from $15 per ton to $20 effective January 1, 2016, and then raise it again in 2017 to $30 per ton. The applicability of the tax was also extended, meaning that households in the province would likely find that their heating, electricity and transportation costs increase by $470 in 2018 assuming they use the same amount of fossil fuels as they did in 2015. The far-ranging climate policy, besides raising the carbon tax for the first time in eight years, also included a cap on oil sands emissions, a phasing out of coal-fired electricity generation and an emphasis on wind power. It is aspects of the electricity plan that have now come back to bite the NDP causing them to run to the courts in an attempt to have judges bail out incompetent bureaucrats.

This year that same megawatt hour of electricity can only be sold for $16, seriously damaging the economics of electric contracts tied to the earlier megawatt prices

The phase out of coal-fired electricity generating plants was scheduled for 2030, but now that date has been moved forward. The cost of operating these coal-fired power plants is rising due to the carbon tax hike and the mandated increase in efficiency targets for large carbon emitters. Low natural gas prices have further undercut the plants' economics. The new carbon tax is estimated to push the carbon cost for electricity from about $2 a megawatt hour in 2015 to $21 in 2017. At the same time, natural gas-powered plants are generating electricity at considerably lower prices. The result is that while coal-fired plants could sell its electricity for $49 a megawatt hour in 2014, that price was down from $80 a megawatt hour in 2013. This year that same megawatt hour of electricity can only be sold for $16, seriously damaging the economics of electric contracts tied to the earlier megawatt prices.

The companies elected to exercise a clause in those agreements to hand back the PPAs that was allowed if a change in law made them "more unprofitable"

After discussions with the government, four power companies, with existing power purchase arrangements (PPAs) with the province's Balancing Pool to purchase electricity produced by these expensive coal-fired power plants, decided to hand them back. The companies elected to exercise a clause in those agreements to hand back the PPAs that was allowed if a change in law made them "more unprofitable." The companies have estimated that the value of these PPAs is $2 billion. A recent report by two Canadian university economists, one who was a chair of the Alberta advisory panel that helped develop the revised provincial climate policy, claims the cost of the PPAs is overstated by $1.4 billion. We aren't going to get into the numbers debate. Suffice it to say that the cost impact is large. It will show up in the form of higher monthly utility bills for households. Furthermore, one of the entities owning a PPA is the Calgary municipal electricity company. It pays its dividend to the City of Calgary that is used to help fund budgetary commitments such as subsidized transit passes for low-income residents. That flow of funds will disappear negatively impacting the Calgary budget and likely resident tax bills.

The clause is being referred to as the "Enron clause" and being sold by the government to the province's residents as a tarnished act because an email written by an Enron employee in 2000 suggested that the provision needed to be included in the final PPAs

The comedy in this episode is that the Alberta government has filed suit against the power companies asking the court to void the provision in the PPAs that allowed the companies to return the agreements if changes in law negatively impacted the PPAs' profitability. The clause is being referred to as the "Enron clause" and being sold by the government to the province's residents as a tarnished act because an email written by an Enron employee in 2000 suggested that the provision needed to be included in the final PPAs. Based on a conversation with one of the PPA negotiators, the clause was well-known to all parties and was not "sneaked" into the agreement at the 11-hour. However, it is on the basis of the email that the Alberta government is claiming the clause was introduced at the last minute and therefore was illegal. The government's media campaign is attempting to show the public that the bureaucrats had done nothing wrong, it was the bad companies who did an illegal act. That argument misses the point on several basis. First, had the bureaucrats read the PPAs, they would have known of the existence of the clause and its potential impact. Secondly, there is nothing illegal about a party exercising its rights under a properly executed contract, especially after the government acted in a way that made the economics of coal-fired power electricity plants more uneconomic. Finally, it was the existence of that contract clause that convinced the PPA buyers to enter into the contracts initially, which have enabled Alberta households to receive C$4.4 billion in credits on their utility bills since 1999.

We have no experience with Canadian courts, so we don't know whether judges are ideologically-bent rather than adherents to the law. If the latter, then there will be no case as the companies are certainly allowed to exercise their rights as defined by the contract. However, if judges are ideologically driven then it is possible the

The bottom line is that when politicians are driven by ideology, their employees (bureaucrats) will do whatever it takes to carry that ideology into effect

companies' rights will be circumscribed by some social well-being mandate. The bottom line is that when politicians are driven by ideology, their employees (bureaucrats) will do whatever it takes to carry that ideology into effect. In this case, that drive resulted in the bureaucrats failing to perform the necessary due diligence by examining the legality of their actions. Increasingly these episodes are appearing in actions to deal with climate change. This should not be a case of acting and then asking for permission.

While this should translate into lower power prices in Canada, a hidden tax for renewable power actually drives electricity bills to high levels

The electricity situation in Ontario is not quite the same, but it flows from the same vessel of ideological purity. The wholesale price for electricity in the province, called the Hourly Ontario Electricity Price (HOEP), has fallen over the past decade from five to eight cents per kilowatt hour (kWh) to now below three cents and often as low as two cents, all thanks to the shale gas revolution. While this should translate into lower power prices in Canada, a hidden tax for renewable power actually drives electricity bills to high levels.

So with the HOEP at around 2.5 cents, someone has to pay for the 11-cent subsidy for wind power, and that is where the GA comes in

The Global Adjustment (GA) is the tax levied on electricity purchases to cover the subsidies for green energy. In 2009, when the Green Energy Act was passed, the HOEP was about five cents per kWh. As the subsidies for wind and solar generators kicked in, the GA jumped from zero to about 3.5 cents per kWh. Today, the GA is about 9.5 cents per kWh, and in April it rose above 11 cents, three times the HOEP. How did this happen? It stems from the Ontario government signing contracts with wind generators that guaranteed them 13.5 cents per kWh. Solar generators actually get paid more. So with the HOEP at around 2.5 cents, someone has to pay for the 11-cent subsidy for wind power, and that is where the GA comes in. Therefore, the more renewable power generated, the greater the GA becomes.

It will account for a greater percentage of total power supplied and thus the GA charge will grow reflecting the greater subsidies

The perverse nature of the GA is demonstrated by the fact that if consumers are good students of their power usage and electricity demand falls, renewable power output doesn't decline. As a result, it will account for a greater percentage of total power supplied and thus the GA charge will grow reflecting the greater subsidies. The power situation is further complicated by the fact that the province, due to its generous renewable fuels subsidies, often exports power to the United States at a loss.

Going back in history, the Ontario power structure was initially adjusted toward a competitive marketplace before climate change policies took over. A report last December by the province's Auditor General (AG) showed that actions such as the conversion of the Thunder Bay coal plant to biomass, using imported wood as a fuel source, will result in electricity costing $1,600 per megawatt hour (MWh). The report also cited a hydropower plant being constructed at $1 billion over the initial cost estimate and thus raising the cost of hydro power to $135/MWh.

From 2009 to 2014, Ontario had to pay generators $339 million for not producing 11.9 million MWh of surplus electricity

The AG report also took issue with the province emphasizing conservation while encouraging more renewable energy generators. The result is a substantial surplus of generating capacity within the province that forces it to sell its surplus power at a lost and boosts consumer power bills. As power is exported below cost, other generators are paid not to produce power. From 2009 to 2014, Ontario had to pay generators $339 million for not producing 11.9 million MWh of surplus electricity.

However, when ideology blinds people to reality, incompetence should not be rewarded

So while Ontario residents actually have the lowest cost power in decades, due to their power industry being restructured to deal with potential climate change issues their bills are the highest they have been and are on track to rise further in the future. Now, Albertans may confront a similar situation as the incompetence of their government has led to the households having to pay for the losses on the PPAs being handed back by the companies who have seen the economics of their power contracts impaired in the name of climate change. That might be acceptable if the action was not done through carelessness or incompetence. However, when ideology blinds people to reality, incompetence should not be rewarded.

U.S. Renewables Enters A New Era – Deepwater Wind Starts

The U.S. renewable energy business will soon enter a new era when the turbines start generating electricity

The wind turbines offshore Block Island, Rhode Island are rising faster than expected due to favorable weather and wind conditions. In fact, the last blades were installed on the fifth wind turbine last Thursday. The U.S. renewable energy business will soon enter a new era when the turbines start generating electricity. Many people may wonder why it has taken the U.S. so long to start an offshore wind industry, given the success of Western European countries.

Gov. Carcieri was wrong about the number of wind farms that would pop up, but he was right that Quonset on Narragansett Bay does provide a convenient location for assembly of wind farm components

Deepwater Wind, the developer of the Block Island wind farm project, started working in 2008 to secure the rights to construct these wind turbines. The idea of offshore wind farms was pushed by then-Rhode Island Governor Donald L. Carcieri (Rep). He believed wind farms would sprout up and down the East Coast and Rhode Island possessed one of the best locations for constructing the components necessary for creating these wind farms. Unfortunately, Gov. Carcieri was wrong about the number of wind farms that would pop up, but he was right that Quonset on Narragansett Bay does provide a convenient location for assembly of wind farm components. That base has been utilized by Deepwater Wind for its project and they plan to use it for future wind farms they are hoping to construct.

The biggest problem for offshore wind is its cost. The first proposed project – Cape Wind – was bedeviled with challenges from wealthy homeowners on Martha's Vineyard and Cape Cod including the late Senator Edward Kennedy and his family, several of the Koch brothers and relatives of numerous influential Washington legislators from both political parties. As the battles continued, the cost of building the 100-turbine project escalated and financing was difficult to secure, causing the electric utility buyers to void their power purchase agreements. While rising costs and lost customers dogged the project, securing the financing may also have been hurt by the on-again/off-again federal tax credits afforded to renewable energy projects.

However, during the PUC hearing, officials of the EDC disclosed that they had not done any economic studies of the project's costs and benefits

The Deepwater Wind project had its trials in reaching completion. The project initially was rejected by the Rhode Island Public Utilities Commission (PUC) in April 2010 for being assessed as "not commercially reasonable." The PUC ruled that the Deepwater Wind plan would impose an increased burden on ratepayers who would be "paying $390 million more for electricity." The PUC also described the project's benefits as "based on speculation." How could this have happened? The governor had testified for Deepwater Wind and the state's Economic Development Commission (EDC) recommended it. However, during the PUC hearing, officials of the EDC disclosed that they had not done any economic studies of the project's costs and benefits. It was just assumed that the economic benefits outweighed the costs. As a result, the PUC decision shocked Rhode Island politicians and set them off to find a way to overturn the ruling. In fact, it took less than 60 days for the Rhode Island General Assembly to pass legislation changing the definition of "commercially reasonable." As a result, the PUC was forced to review the project in a second hearing using the newly "watered down" definition of "commercially reasonable."

"Apparently dissatisfied with the Commission's findings, on June 10, 2010, both chambers of the General Assembly passed amendments" to the original legislation

The gamesmanship ongoing with the project was not lost on the PUC. It wrote in its 2-1 decision approving the project under the new standard: "Apparently dissatisfied with the Commission's findings, on June 10, 2010, both chambers of the General Assembly passed amendments" to the original legislation. In the rehearing, the PUC was still reluctant to approve it, but was challenged on its questioning of the basis for the evaluation. Lawyers for National Grid (NGG-NYSE), the dominant electric utility in Rhode Island and the purchaser of the wind farm's power, wrote the following in a commission filing in response to questions by the PUC. (Emphasis added.)

"There was no cost/benefit condition placed on this inquiry"

"In contrast, when Section 7 was amended, the General Assembly only sought a finding from the Commission that economic development benefits were likely. There was no cost/benefit condition placed on this inquiry. For the Commission to now employ a test which mirrors the one contained in Section 8 is for the Commission to ignore the statute. There are many occasions when the General Assembly has enacted law where it leaves the Commission a considerable amount of discretion to set policy and establish the parameters through which it should be implemented. But Section 7 of Chapter 26.1 is not one of them. The General Assembly required the parties to return to the Commission with a new contract. But, in doing so, the General Assembly set forth some

"The Commission should not re-write and expand the standard to establish a virtually insurmountable hurdle, as the opponents would prefer"

very clear standards. **It is not the role of the Commission in this case to create a higher bar for the approval of the power purchase agreement than otherwise exists in the plain language of the amended Section 7**. While the Commission had to employ a standard that was not separately and explicitly set forth in Section 7 in Docket No. 4111, the new amended Section 7 does not contain such an interpretative gap. The gap has been filled and the standard is now clear and unambiguous. The Commission should not re-write and expand the standard to establish a virtually insurmountable hurdle, as the opponents would prefer."

It is clear from National Grid's response that it was doing the politicians' bidding and was not interested in being held to a higher standard than the General Assembly established in the revised legislation. The National Grid lawyers went on to further dismantle any objections. They wrote:

The General Assembly has spoken with a policy judgment that this small demonstration project is important to the state of Rhode Island, even though they were aware that a rate increase is likely to accompany it

"The opponents will argue that a net benefits test should be applied and find case law from other contexts in which courts have required agencies to apply a net benefits test, even when the statute does not otherwise specify it. But the statute in this case is quite unique. It is not establishing a standard that will be applicable to a multitude of future applications, the implications of which could create undesirable results. **This statute pertains to one project and one agreement**. There is a specific history that must be taken into account. To ignore the limited application of this law and employ reasoning that is suited to regulations that have wide scope and application is simply an excuse to ignore the will of the General Assembly in this case. While some of the Company's customers who oppose the project may be understandably concerned about an agreement which is likely to result in a rate increase, this concern is not a consideration under the law. The opponents may not like the law. But the law must be implemented as written. **The General Assembly has spoken with a policy judgment that this small demonstration project is important to the state of Rhode Island, even though they were aware that a rate increase is likely to accompany it**. That policy judgment must be accepted, and the plain language of the amended law implemented."

You got your marching orders from the General Assembly and are to approve this power purchase agreement, even if you have to hold your nose while doing it

What the National Grid lawyers were saying was: Don't you guys understand? You only need to find that there are economic benefits in this project. It doesn't matter whether they are less than the costs inflicted on all the ratepayers in the state. You got your marching orders from the General Assembly and are to approve this power purchase agreement, even if you have to hold your nose while doing it. It's all about creating a new industry for Rhode Island and the cost of that effort should be borne by the residents of the state.

Surprisingly, the decision was only 2-1. Rhode Island Attorney General Patrick C. Lynch was stunned by the decision, calling it an "inside deal." He and several other ratepayers appealed the PUC's

The justices wrote that they hoped it turned out to be as good for Rhode Island as Seward's Folly was for Alaska

decision to the Rhode Island Supreme Court. In 2014, the court was forced to affirm the decision, but the justices wrote that they hoped it turned out to be as good for Rhode Island as Seward's Folly was for Alaska. Now that Deepwater Wind is close to starting operation, so do the ratepayers. As they contemplate the 24.4 cents per kilowatt hour that Deepwater Wind power will cost, they will be looking at their latest power bills showing an energy cost of 8.679 cents per kilowatt hour – a 15.7 cent difference.

That cost estimate was between the comparable German wind price of $214/MWh and that of the UK at $233/MWh

We wonder about the economics of this project. In 2010, during the first PUC hearing, the cost of the wind farm, which was then composed of eight turbines with a total nameplate capacity of 28.8 megawatts (MW). The estimated cost of the wind farm was $181.98 million without the cost of the transmission cable. The economic model suggested that the bundled energy price was $229.03 per megawatt hour (MWh), or 22.9 cents per kilowatt-hour (kWh). That cost estimate was between the comparable German wind price of $214/MWh and that of the UK at $233/MWh. With the inclusion of the $42 million cable cost, the bundled energy price was above the UK price, acknowledged to be the highest market price at that time.

Based on the $229.03/MWh bundled energy price, estimated for 2009, with the annual 3.5% escalation, in 2032 the cost to ratepayers would be $505.27/MWh, or 50.5 cents/kWh. That pricing schedule was estimated to create $440 million in above-market payments by rate payers over the 20-year life of the contract.

But as time has passed, the cost escalation plus the lower current energy cost has escalated the ratepayer over-payment to $497 million

Now, the project cost is $300 million for five turbines with 30 MW capacity, without the $42 million cable paid for by the power buyer. The price is still scheduled to start at 24.4 cents/kWh. But as time has passed, the cost escalation plus the lower current energy cost has escalated the ratepayer over-payment to $497 million as reported in a 2014 PUC filing and then over $500 million in a 2015 filing. So why is Rhode Island building this project?

A new requirement for utilities to contract 1,200 megawatts (MW) of imported Canadian hydroelectricity and an additional 1,200 MW of offshore wind

In neighboring Massachusetts, the frustration about the pace of renewables penetration into the state's power supply mix and concerns about the loss of generating capacity as the Pilgrim nuclear plant closes in May 2019 and several coal-fired power plants have or are about to close, the state legislature enacted An Act To Promote Energy Diversity. The legislation, which was signed into law by Governor Charlie Baker (Rep), carves out of the Massachusetts renewables mandate a new requirement for utilities to contract 1,200 megawatts (MW) of imported Canadian hydroelectricity and an additional 1,200 MW of offshore wind.

To put the wind mandate into perspective, the Rhode Island project is 30 MW and the proposed Cape Wind project on Horseshoe Shoal in Nantucket Sound would have had a nameplate capacity of 468 MW. So what might the Massachusetts wind energy cost? Based on Deepwater Wind, there needs to be 40 of them at an estimated

Cape Wind was estimated to cost $2.5-$3.0 billion so you would need three, at a cost of $7.5-$9.0 billion

cost of $12 billion. Cape Wind was estimated to cost $2.5-$3.0 billion so you would need three, at a cost of $7.5-$9.0 billion. Massachusetts seems to be staking its mandate on a new study from The University of Delaware that projects that developing offshore wind at scale through 2030 could reduce the price to 10.8 cents/kWh. That cost estimate is based on further improvements in the performance of wind turbines and that larger projects will lead to economies of scale. The real problem with this cost estimate is that it is based on levelized cost analysis that assumes all power is of equal value regardless of when it is produced. The levelized cost analysis also ignores the cost of backup power, which is an important consideration since wind is an intermittent power source.

In mid-July, Louisiana's Department of Revenue said it was almost $30 million short of funds to pay already submitted claims for rooftop solar systems and that there were no funds to pay future claims

So with offshore wind being expensive and costly for ratepayers, as shown by the cost differential Rhode Island ratepayers will pay, a new renewables issue is emerging. That issue is the subsidy being paid for solar power by various states. Louisiana has just announced it has run out of money for solar facilities. In mid-July, Louisiana's Department of Revenue said it was almost $30 million short of funds to pay already submitted claims for rooftop solar systems and that there were no funds to pay future claims, even though the program is not scheduled to end until Dec. 31, 2017. The 2015 law capped the state's credit program for 2015-2016 and 2016-2017 at $10 million and $5 million for 2017-2018. With a generous plan – 50% of system costs, capped at $25,000 for a system – and a utility rate structure that has a block pricing structure with the first power being the most expensive, solar power has been popular in Louisiana. The state also provides cash payments for those with incomes too low to use all their tax credit rebates. According to the Solar Energy Industries Association, 32 MW of solar power was installed in Louisiana in 2015, up 3% from the prior year. The industry association expects another 208 MW to be installed over the next five years.

If all those applications are processed, then more rooftop solar installations will occur in 2016 than in all prior years combined

New Mexico is ending its solar tax credit that was put in place in 2008 with a 2016 sunset date. The plan was capped at $3 million per year, which was exceeded in each of the past four years. The cap was met earlier in each successive year. Utah is seeing solar power booming due to its generous tax credit program. From 3,000 rooftop solar installations in 2015, the government expects to process 12,000 applications this year. If all those applications are processed, then more rooftop solar installations will occur in 2016 than in all prior years combined. With a tax credit equal to 25% of the cost of a system, capped at $2,000 per system, the rapid growth in installations has state officials concerned.

When the tax credit program started in 2012, it was a $1 million program. This year it will reach somewhere between $25 and $40 million. The Utah tax credit comes up for review in 2017. People recognize that the solar, as well as wind, tax credits were put in place to help promote the growth of the industries. Now that they are becoming mature, state officials have to consider whether and when to shut down the programs. Those decisions are not easy or popular given the environmental movement, but state budgets are beginning to drive the decisions.

The question going forward will be the cost of these renewables – wind and solar – and their strain on government budgets, let alone ratepayer costs

With Deepwater Wind, the renewable energy business in the United States has entered a new era. The question going forward will be the cost of these renewables – wind and solar – and their strain on government budgets, let alone ratepayer costs. Additionally, there will be the issue of the growth of intermittent power and the ability of the grid to handle that power variability. It also ignores the issue of power transmission, especially with wind and industrial solar power. That issue is becoming divisive within the environmental movement.

Insuring Adequate Power Is Challenging For All Parties

Energy availability is often ignored until it isn't available

Energy availability is often ignored until it isn't available. Whether that is a grid power outage such as those in 1965 and 2003 that blacked out the Northeast region of the country, or the loss of power at your home or work, the issue of insuring adequate energy availability isn't a high priority for most people, until you don't have it. Often this issue resides in the courts because the public has already made its stand, either for or against.

In the West Coast case, environmentalists are fighting over the federal government's approval for transmission lines to cross federal land that would facilitate bringing wind power to market from a new wind farm

Two interesting examples – one on each coast of the U.S. – demonstrate how the battle over energy infrastructure expansion may limit future energy supply. In one case, the battle is over transmission lines for a wind farm in Oregon, while the other involves a natural gas pipeline project in the Northeast. In the West Coast case, environmentalists are fighting over the federal government's approval for transmission lines to cross federal land that would facilitate bringing wind power to market from a new wind farm. Environmentalists fighting clean energy? This battle reminds us of a federal legal struggle between government mandates requiring an Oregon dam operator to manage its water flow in such a way to insure preservation of a federally-protected fish, when by doing so it could not comply with a different mandate to deliver green power to California. In this case, the fish won but California's residents and the Oregon dam operator lost.

That means using coal and petroleum powered plants creating dirtier air

In the Northeast, the supply of natural gas for generating electricity is constrained by the inability of utilities to secure adequate long-term supplies. As a result, during the winter when electricity consumption and natural gas heating demand peak, the utilities are forced to activate other fossil fuel-powered plants. That means using coal and petroleum powered plants creating dirtier air. A solution conceived by the Massachusetts Department of Public Utilities (DPU) was to interpret its mandate to allow electricity utilities to levy a charge on their customers to help fund the construction of natural gas pipeline expansions that would bring long-term gas supply to them and reduce the winter price spikes. Last week, the

It was that provision that the regulators relied on for approving long-term contracts, but the plaintiffs disagreed and the court sided with them

Massachusetts Supreme Court ruled on a case brought by environmental groups challenging the DPU's mandate interpretation under the state's 1997 Restructuring Act that separated the utility services of generation, transmission and distribution, and deregulated the generation component in the interest of competition. That Act does allow long-term contracts for supply, but the price to be paid is subject to department review. It was that provision that the regulators relied on for approving long-term contracts, but the plaintiffs disagreed and the court sided with them.

"Today, our highest court affirmed Massachusetts' commitment to an open energy future by rejecting the Baker administration's attempt to subsidize … the dying fossil fuel industry"

David Ismay, the lead attorney for the Conservation Law Foundation who filed the suit, said, "This is an incredibly important and timely decision. Today, our highest court affirmed Massachusetts' commitment to an open energy future by rejecting the Baker administration's attempt to subsidize … the dying fossil fuel industry." Further, he made the point that this shifted the burden onto the companies, who he perceives as being leery of funding new pipeline construction "without having long-term contracts in place."

Exhibit 11. Gas Supply Expansion For Northeast In Jeopardy

Source: Spectra Energy

That assumption is being challenged by the Massachusetts Attorney General who had a study done showing that through demand management and more renewables, the state didn't need more gas capacity

This decision will impact the Access Northeast expansion plan of Spectra Energy (SE-NYSE) as Maine had a similar plan in place, but which required the approval of the other five New England states. Rhode Island, where the battle over Spectra's pipeline expansion is wrapped up in an ongoing war over building a new gas-fired power plant in Burrillville, has a similar provision that is likely to fail without other state agreements. Based on the court ruling, Spectra said it was "extremely disappointed" and would need to "reevaluate our path forward – consistent with the court's decision – to provide the infrastructure so urgently needed by New England's electric consumers." That assumption is being challenged by the Massachusetts Attorney General who had a study done showing that through demand management and more renewables, the state didn't need more gas capacity. One project that will not be built was the planned LNG regasification facility for Massachusetts with 6.8 billion cubic feet of gas storage as Spectra had acknowledged it was uneconomic without the contractual support.

The impact of the Massachusetts legal decision is not positive for the Marcellus gas basin

The environmental battles over energy infrastructure expansions will continue to ramp up. The impact of the Massachusetts legal decision is not positive for the Marcellus gas basin, which could further hurt the recovery in natural gas consumption and hold back the recovery in natural gas prices. The bottom line from these examples is that the risk of energy projects is creeping higher and that will filter into energy company spending – hurting both the nation's future energy supply and its profitability for the companies.

The Logic Of Attacking Heavy-duty Truck Fuel Efficiency

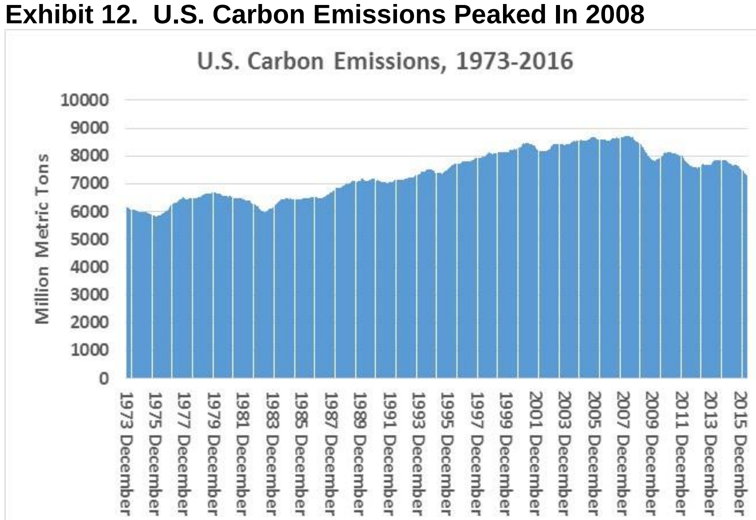
This group includes the largest pickup trucks sold as well as the traditional 18-wheelers on the highways

The Obama administration's Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA) released their Phase II fuel efficiency and greenhouse gas emissions regulations for heavy-duty trucks. This group includes the largest pickup trucks sold as well as the traditional 18-wheelers on the highways. The standards are to be phased in between the 2021 and 2027 model years. The existing standards, which were designed for the 2014 through 2018 model years, will remain in place until the new standards take effect.

They currently account for about 20% of carbon emissions, yet only account for about 5% of the vehicle population

The heavy-duty truck standards come as the government has just begun negotiations with auto manufacturers over the final fuel efficiency ratings for light-duty vehicles where the industry is lagging behind the targets in the standards. Heavy-duty trucks are the second largest and fastest growing segment of the U.S. transportation system measured by their emissions and energy use. They currently account for about 20% of carbon emissions, yet only account for about 5% of the vehicle population.

Exhibit 12. U.S. Carbon Emissions Peaked In 2008



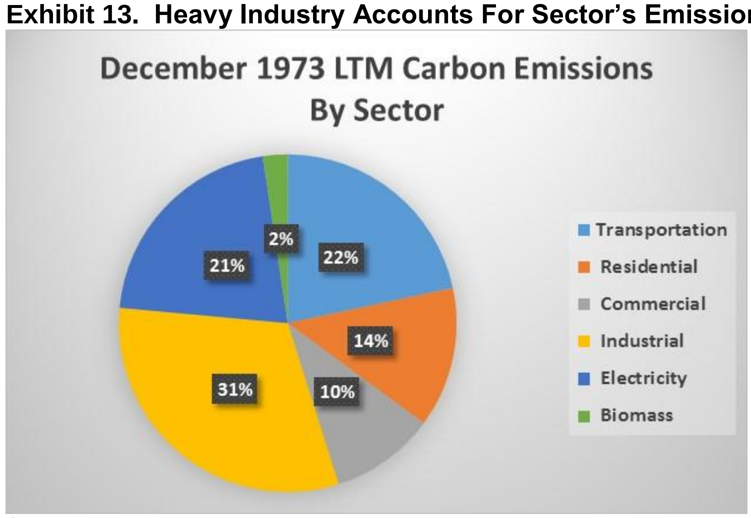
Source: EIA, PPHB

Carbon emissions from transportation is now the largest contributor to overall greenhouse gas emissions. Three charts showing

It should be noted that the country's total carbon emissions peaked in January 2008 and have declined steadily since

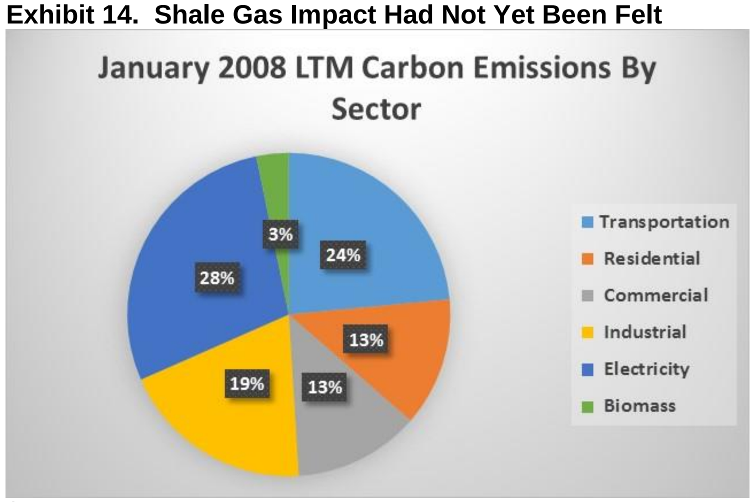
annualized sector shares of total emissions confirm this conclusion. It should be noted that the country's total carbon emissions peaked in January 2008 and have declined steadily since. On an absolute basis, over the past 8 1/3 years there are 1,410.1 million metric tons of less carbon emissions, or a decline of 16.2%. The transportation sector contributed about 9.1% of that decline. The significance is that transportation's emissions dropped 6.4% over that time span while overall emissions declined 16.2%. The overall figure reflects the sharp decline from coal's use due to the shale revolution and low natural gas prices along with static electricity consumption. At the same time, the decline and then flat trend in vehicle miles driven coupled with more fuel-efficient autos also helped reduce the transportation sector's emissions. One can see these trends at work by looking at the sector shares in 1973, 2008 and 2016.

Exhibit 13. Heavy Industry Accounts For Sector's Emissions



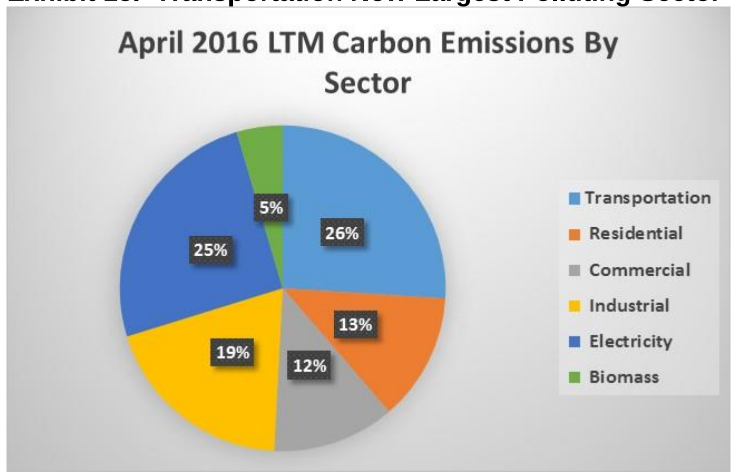
Source: EIA, PPHB

Exhibit 14. Shale Gas Impact Had Not Yet Been Felt



Source: EIA, PPHB

Exhibit 15. Transportation Now Largest Polluting Sector



Source: EIA, PPHB

Going forward, the energy policies targeting the transportation sector, coupled with technological improvements in overall energy use, will become more important in driving down carbon emissions

The United States has done well in reducing its carbon emissions by 16.2% since the start of 2008. The weak economy and energy revolution have been primarily responsible. Going forward, the energy policies targeting the transportation sector, coupled with technological improvements in overall energy use, will become more important in driving down carbon emissions. Thus, the reason for the heavy-duty truck standards. They have support from the industry and truck manufacturers who see economic opportunities from more efficient engines. The Independent Truck Owners Association estimates the new standards will add $12,000-$14,000 to the cost of new tractors, which often cost upwards of a quarter of a million dollars, but they hope to recover those higher costs through improved fuel efficiency.

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