ENERGY INDUSTRY DATA AND TRENDS

Service Cost Inflation and its Effect on Well Economics

March, 2017

Welcome to the EnerCom Energy Industry Data and Trends for March 2017. This month, we explore expected cost inflation from service providers and what it will mean for E&P operators moving forward.

As drilling and completion activity continue to increase, the oil and gas industry is preparing for increased costs from oilfield service companies. The limited availability of services is in the forefront of upstream operators' minds so we decided to find out where to expect those costs to increase, and what it will ultimately mean for well economics.

In This Report – Key Summary Points:

- Service costs are expected to increase 10% to 15% with most analysts anticipating that we will reach the high-end of projections
- Most basins can absorb a 20% increase in service costs at $50 oil
- Lower oil prices quickly change that picture, however, with IRRs in every basin dropping below 20% with a 15% increase in service costs at $45 oil
- Pressure pumping and frac sand are expected to be the major drivers of higher service costs, with pressure pumping expected to increase 20% to 30%
- Many E&P companies saw this coming and negotiated long-term contracts with their service providers to protect against cost inflation
- Long-term contracts appear to have the desired effect in some basins, but are not a panacea for lower oil and gas prices
- Service companies are looking for ways to innovate and dramatically reduce the number of days needed for completions while increasing EURs
- E&P companies are already starting to bid up service costs. If that continues, higher oil prices could lead to an even higher costs on the service side

On the tip of everyone's tongue

With our first EnerCom Dallas conference under our belt, we here at EnerCom decided to examine one of the recurring trends we saw from our event: service costs.

We all knew that eventually the price of oilfield services were bound to increase. The oil and gas downturn prompted many upstream companies to turn to their service counterparts and look for ways to cut costs to help ensure that operations remained economic. As oil prices increased from a trough of $26.21 on February 11, 2016, drilling picked up, and service costs are expected to rise along with it.

As far back as second quarter 2016, companies such as Halliburton were discussing the necessity of higher service costs, and during the course of EnerCom Dallas we heard multiple E&P companies coming to the same conclusion.

"Rig efficiencies are sustainable. The speed that we can drill out laterals is sustainable. The bigger jobs and higher production is sustainable. But that doesn't come without a cost," Halliburton CEO David Lesar said back in July during the company's conference call. "[Our customers] know in their heart of hearts that service prices have to go up. They are going to fight that impact of prices coming up as fast and as long as they can, but the reality is – they know they need a viable service industry to be successful in the long run."

E&P companies were not as quick to project higher service costs, but many are on the same page now and are already looking for ways to ensure that drilling continues to provide high rates of returns even as cost inflation on the service side takes hold.

Service costs are expected to increase 10% to 15%

Throughout our two-day investor conference we heard E&P companies reiterate that they are expecting service costs to increase 10% to 15% over the course of 2017, with WPX CEO Rick Muncrief saying he had heard they might go as high as 20% for some companies. Consensus among E&P companies is encouraging when trying to determine where prices might go, but we decided to dive a bit deeper and ask analysts where they saw costs going as well.

On both the buyside and sellside, analysts agreed with E&P companies' assessments that prices would increase 10% to 15% moving forward. One buyside analyst said there was some bias to higher costs, with his estimate at 10% to 20%, but by and large the industry and everyone observing expects costs to increase in the same range, giving us a fair amount of confidence that service costs will increase between 10% and 15% this year.

What rising service costs mean for returns

With a good sense of where we believe service costs are headed, EnerCom Analytics then looked at what those rising costs would mean for well economics. In the end, E&P companies want to be sure their wells are going to generate rates of return that allow them to continue growing. In our January Energy Industry Data and Trends, we found that investors are willing to concede a premium to companies that can grow debt-adjusted production by more than 20%, but companies need to ensure that the wells they drill are returning enough capital to execute their current drilling program in addition to increasing production sequentially.

For the purposes of our analysis, we define an "economic" well as one that generates a 20% internal rate of return (IRR).

Using our well economics models, including acreage acquisition costs and realized prices, EnerCom looked at the effects of rising service costs in the Eagle Ford, Delaware, Midland, Bakken, Marcellus and Niobrara. We found that many of the leading basins continue to be economic even if service costs rise more than 20% at $50 oil or better. This is a tremendous improvement over where the industry was a little less than two years ago. In our June 2015 Energy Data and Trends, only the Marcellus generated IRRs in excess of 20% at $3.81 per MMBtu and $74.34 per barrel of oil, and none of the basins generated economic rates of return at $3.50 realized natural gas and $50.00 oil.

The outcome of our models today remains affected by the price of oil we use, however, with only the Midland basin able to sustain service cost inflation of more than 10% at $45 oil. Each of the basins were able to withstand a 15% increase at $60 oil, but if increases surprise to the upside the Niobrara may quickly become uneconomic to drill.

The Eagle Ford, Permian and Bakken can withstand more than 20% cost inflation

Assuming $50 oil prices moving forward, many of the most active regions in the United States will continue to generate at least 20% internal rates of returns, our baseline for an economic well.

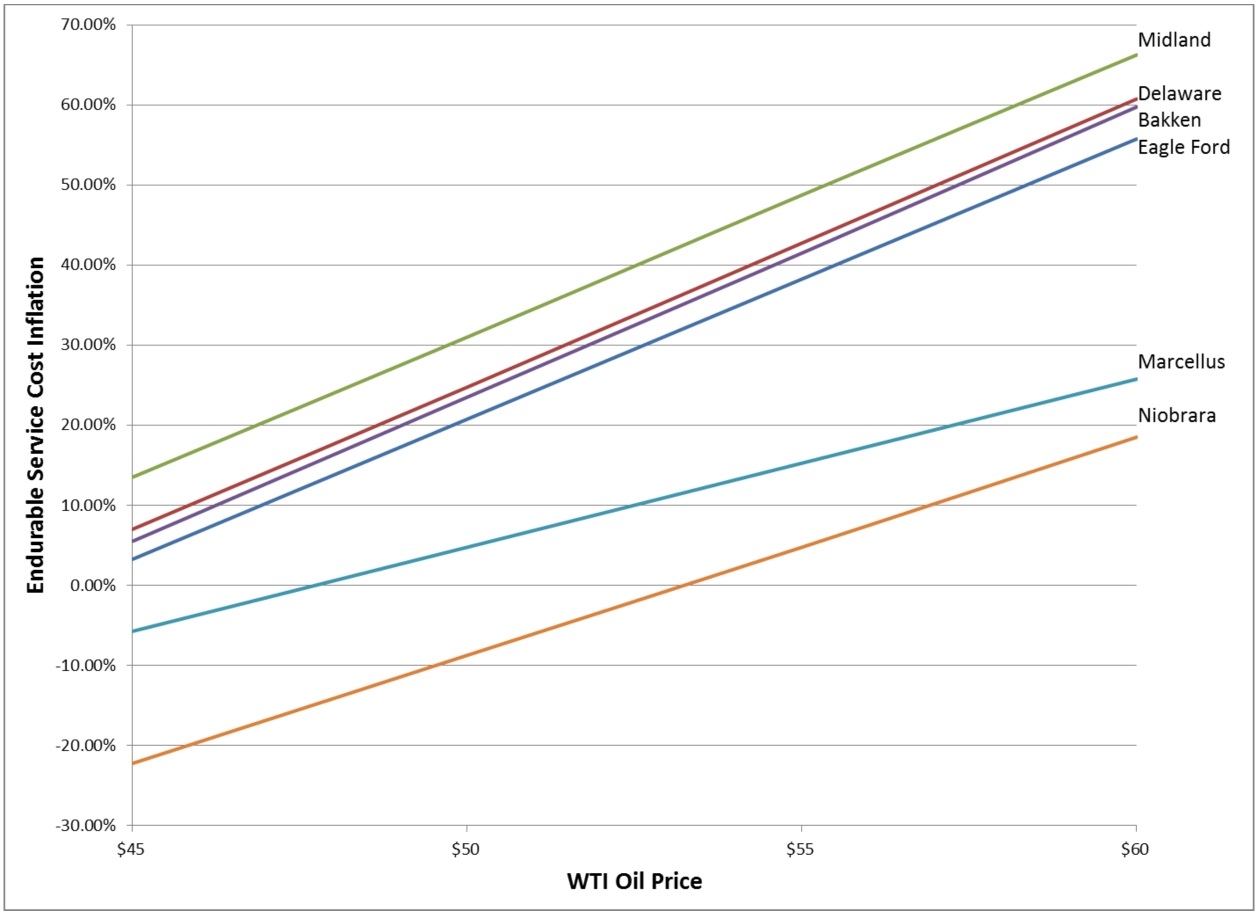
Based on our well economic models, wells in the Eagle Ford continue to have at least 20% IRRs even if service costs increase by 20.75% at $50 oil. Using the same assumptions, the Bakken is able to sustain an increase of 23.5% in service costs, the Midland Basin is able to withstand 31% higher costs on services, and wells in the Delaware Basin continue to return 20% IRRs even with a 24.75% increase in service costs.

The stronger performance of the Midland Basin compared to the Delaware was consistent throughout EnerCom's analysis. This is primarily due to acreage costs in the Delaware, which are significantly higher than elsewhere in the Permian, hindering economics. Our Delaware model assumes an average cost of $33,000 per acre making the acreage 1.6-times more expensive than the average $20,000 per acre seen in the Midland.

	Midland	Delaware	Eagle Ford	Bakken	Niobrara	Marcellus
Well Cost (Millions)	$6.30	$6.98	$3.88	$6.14	$4.08	$6.96
30 Day IP (BOEPD)	1200	1725	887	1330	570	1720
Acreage Cost ($/Acre)	$20,000	$33,000	$3,500	$7,500	$5,000	$6,000
EUR (MMBOE)	1194	1394	629	1070	531	2945

Acreage valuations in the Delaware basin can vary significantly, but are typically some of the highest seen in the U.S. Resolute Energy's recent Reeves County acquisition, for example, had an acreage valuation of $23,000 per acre according to Capital One. ExxonMobil's acquisition of the Bass Family acreage realized a similar acreage valuation, according to PLS. Diamondback Energy made a large Delaware basin acquisition in December with an estimated acreage valuation of $32,000 per acre, while Halcon Resources's January acquisition valued acreage at $34,000 per acre.

Midland Basin acreage costs do not always reach the heights seen in the Delaware, but are still high. Parsley Energy's Midland Basin acquisition in January had an acreage valuation of about $18,600 per acre. Concho Resources's August acquisition in the Midland Basin represented an acreage valuation of approximately $25,600 per acre.



The Marcellus and Niobrara, however, do not have as favorable economics when considering rising service costs. At $2.50 gas, our well economic models suggest that wells in the Marcellus could withstand a 4.75% increase in service costs while still generating 20% internal rates of return. The Niobrara shows the most strain under rising service costs with our models showing costs would actually need to decrease approximately 8.75% at $50 oil for the average well in the play to generate 20% IRRs or better.

As oil prices hold below $50 per barrel, service costs could be more of an issue

On March 9, 2017, oil prices broke below the $50 per barrel mark and as of the date of this letter WTI is trading at $46.68 per barrel. Any drop in price will have a meaningful impact on well economics, but a drop to $45 per barrel will make 20% or greater IRRs much more difficult to achieve. Of all the basins analyzed, only the Midland can generate a 20% IRR with $45 oil and expected service cost inflation. If oil prices do sit in the mid-$40 range, the Midland could absorb as much as a 13.5% increase in service costs, but, given the bias toward the higher end of the 10% to 15% range, this could mean that even the Midland will see IRRs drop below 20% if WTI remains in this range for a sustained period of time.

The other basins fare worse at $45 oil with the Delaware able to sustain a 7.00% increase in service costs, the Bakken able to withstand a 5.50% increase and the Eagle Ford becoming uneconomic after a 3.25% increase in service costs. The Niobrara would need to see service costs lowered 22.25% at $45 oil to remain, according to our models. Assuming $2.50 realized natural gas prices, the Marcellus can only withstand a 4.75% increase in service costs.

	$45 Oil	$50 Oil	$55 Oil	$60 Oil
Eagle Ford	3.25%	20.75%	38.25%	55.75%
Delaware	7.00%	24.75%	42.75%	60.75%
Midland	13.50%	31.00%	48.75%	66.25%
Bakken	5.50%	23.50%	41.50%	59.75%
Niobrara	-22.25%	-8.75%	4.75%	18.50%
	$2.25	$2.50	$2.75	$3.00
Marcellus	-7.75%	4.75%	17.25%	29.75%

Table: Sustainable levels of service cost inflation by basin at various oil prices and realized gas prices for the Marcellus. Oil prices were held constant at $50 per barrel for the Marcellus analysis

The Marcellus holds up favorable at $3.00 realized gas prices

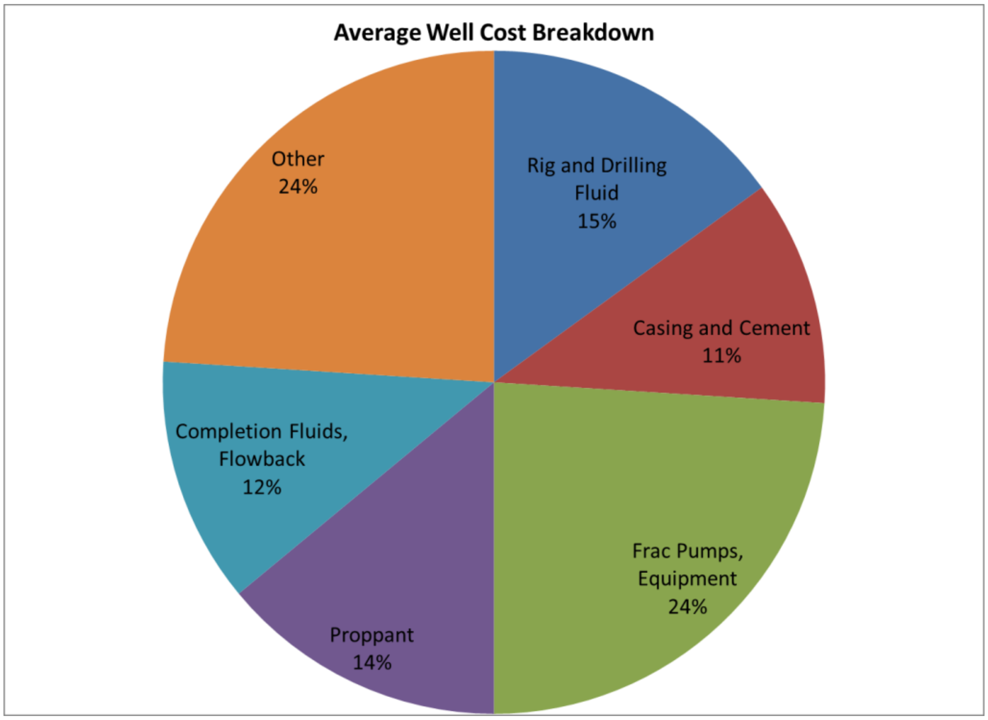
Holding oil prices constant at $50 per barrel and instead looking at the effects of service costs on natural gas prices, Marcellus wells can withstand a 29.75% increase in service costs at $3.00 realized gas prices. Gas produced from the Marcellus trades at a discount to Henry Hub prices, however, and lower realized prices quickly hinder the economics of wells in the region.

Lowering the realized natural gas price to $2.25 per Mcf and holding oil at $50 per barrel, Marcellus wells would need to see a 7.75% reduction in service costs to maintain IRRs above 20%. At $2.50 per Mcf, Marcellus wells can absorb a 4.75% increase in service costs, and at $3.00 per Mcf the play remains economic even if service costs increase 29.75%.

Pressure pumping and sand are the major concerns

While examining well economics as service charges change offers an important illustration of how rising costs could affect E&Ps, no one expects that costs will increase uniformly across the board. Based on presentations from our conference, and conversations with buyside and sellside analysts, pressure pumping and frac sand will likely be the two major drivers of increased service costs.

Based on information put out by the Energy Information Administration (EIA) in March of 2016, we have broken down the service costs as follows:

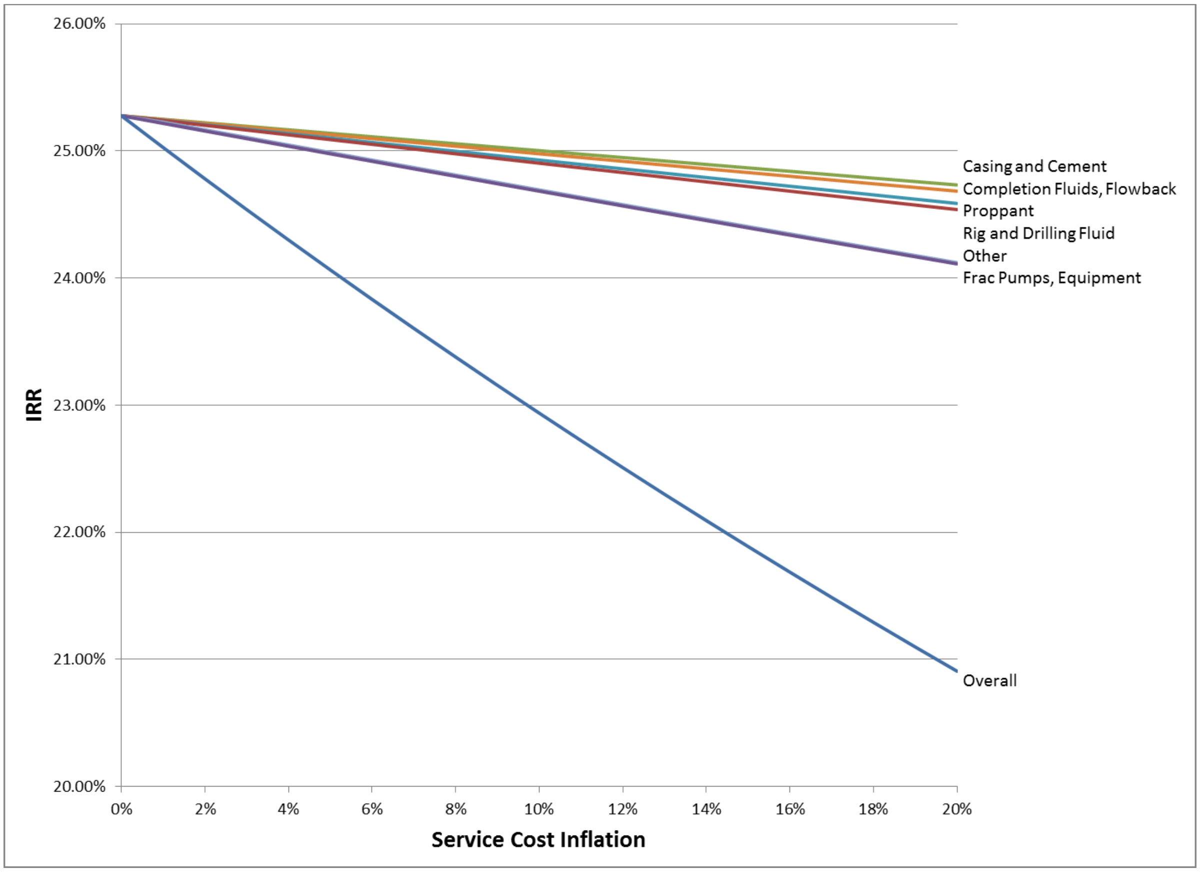


As the length of laterals continues to increase and companies pump more proppant into their wells for more intense completions, pressure pumping and frac sand are likely to see more cost inflation than other portions of the service cost equation. One analyst that spoke with EnerCom indicated that pressure pumping could be especially susceptible to cost inflation, with prices going up 20% to 30% for that service.

Given that each service only makes up a piece of the larger picture, the increases in pressure pumping have a more muted effect on IRRs in each of the basins. A 30% increase to frac pumps and equipment translated into an approximate 2% reduction in IRRs compared to current service costs across the board, with a wider spread as oil prices increased.

Inflations in sand costs are more challenging. Over the course of 2016, prices in the sand market increased 75% to 100%, according to WPX Energy Director of E&P Services Alan Killion, but whether or not that inflation will carry forward into 2017 as well is hard to predict.

"Current sand capacity is listed at 110 million tons per year. In 2016, demand was approximately 40 million tons per year. 2017 projections are around 50 million tons per year, with 2018 pushing more toward 80 million tons," said Killion, but those numbers include all types of sand, not just the fine sand that is in high demand for the more intense frac jobs.

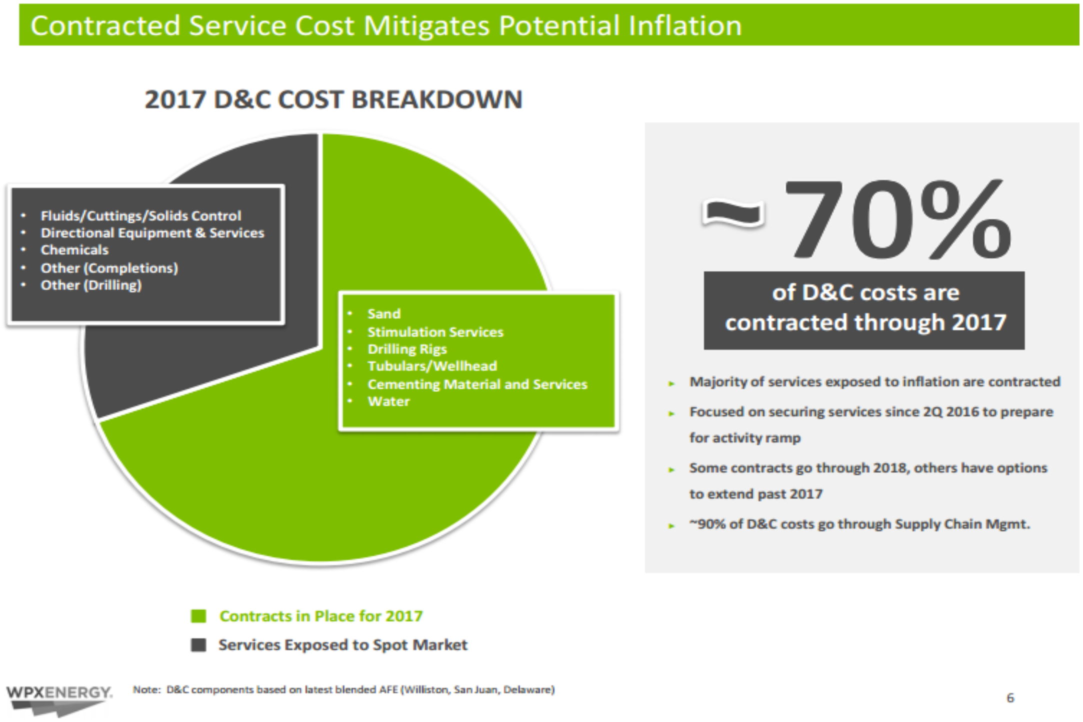


Breaking out each of the individual service costs associated with a well in the Delaware, frac pumps and "other" costs reduce the IRRs of wells the most dramatically as service costs increase. Separately, individual services outside of pumps and other costs only affect IRRs by 1% over the range of 0% to 20% cost inflation, but taken together, a 20% service cost increase can reduce IRRs by nearly 5% over the same range, assuming $50 oil.

The effect of service cost increases is largely the same for each basin, although most do not have the same favorable starting point as wells in the Delaware. The Midland Basin had IRRs starting at 26.5% assuming $50 oil and no service cost inflation. Using the same assumptions, the Eagle Ford model started at 26.8% IRRs, the Niobrara started at 17.9% IRRs, the Bakken saw IRRs start at 26.4%, and the Marcellus had baseline IRRs of 20.8% at $50 oil and $2.50 realized gas prices.

E&Ps saw this coming and are preparing

These increases in service costs were not a surprise to the E&P sector. Many saw it coming, and some were able to mitigate future downsides through long-term contracts with their service providers. WPX, for example, believes that 70% of its service costs moving forward will be protected from any future cost inflation thanks to contracts they have been working on throughout the last year.



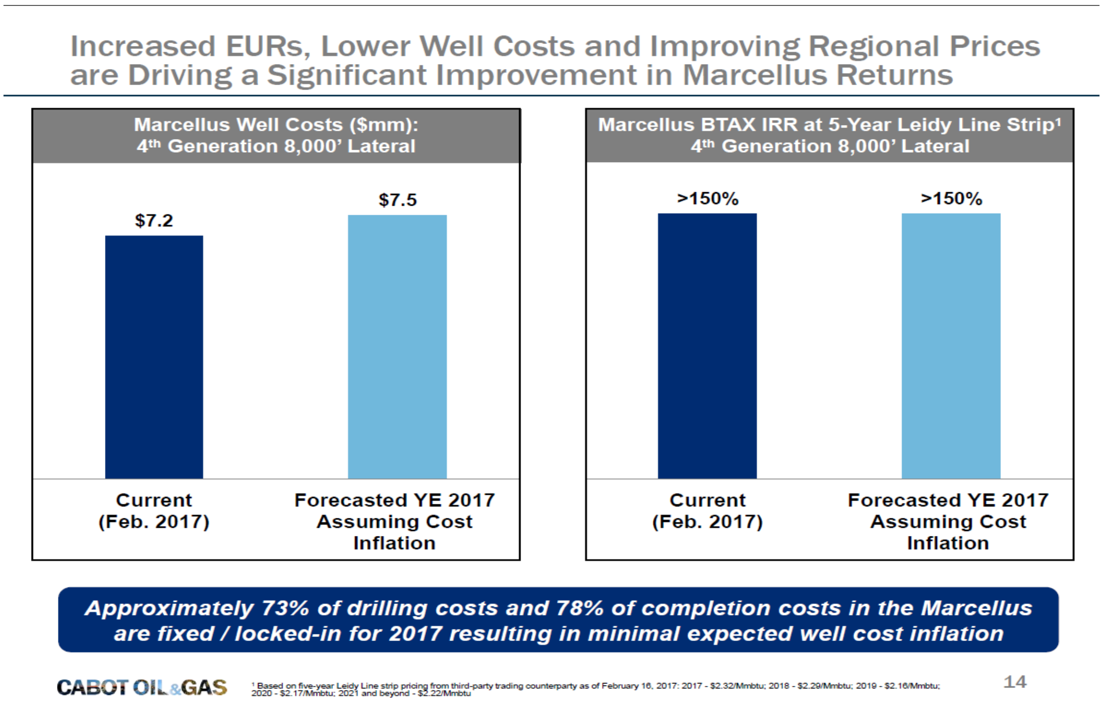
"WPX has been proactive over the past year to work with the service providers on longer-term partnerships that are shielding WPX from the brisk pace of inflation," said Killion. "Our goals are to find partners who want to grow with WPX long-term. Contracting with those companies requires an understanding of not only the current marketplace but also an alignment of goals."

Assuming that only 30% of WPX's service costs will experience inflation, we can increase those services that are still at risk of increasing by more than 100% at $50 oil without IRRs on Delaware Basin wells dipping below 20%. Running a similar analysis at $45 oil, the 30% of service costs left exposed could be increased by as much as 45% before the wells become uneconomic, suggesting that WPX's long-term contracts will give the company more than ample room to absorb rising service costs, even if oil prices remain below $50 per barrel.

Natural gas plays are less insulated from rising costs

Outside the Delaware Basin, it becomes more difficult to protect IRRs from rising service costs, even with long-term contracts. Cabot Oil & Gas reported that approximately 78% of their completion costs are locked-in for 2017, but even taking that into account well economics are not able to stand up to the same kind of stress in the Marcellus as they are in the Permian.

Our Marcellus well economics model shows that wells in the region continue to generate 20% IRRs at $50 oil and $2.50 per Mcf realized gas prices if the 22% of service costs not covered by Cabot's long-term contracts are raised 20%, but the models are not able to absorb a larger increase. Given that 20% seems to be the high-end of expected service costs increases, Cabot will likely be able to continue drilling economic wells, but if realized prices for gas decrease, that margin will compress quickly.



Wells are stretching the limits of existing technology

Service companies are leveraging existing technology to drill and complete longer and longer lateral wells. Eclipse Resources' Purple Hayes "superlateral" well extended roughly 3.5 miles, and the service companies involved used existing technology to complete the well.

"We used all off the shelf equipment and technology," Eclipse COO Tom Liberatore told EnerCom. "We didn't really create anything. We just worked on the combination, particularly of the completion fluid, of what works best in terms of what allows us to place the most sand in slickwater, using the least amount of water and recovering the most amount of water."

The service companies involved in the well, Halliburton and Deep Well Services (DWS), both said they used existing equipment to complete the 124-stage well. Both Halliburton and DWS commented on the fact that the well was exceptionally well-drilled making it possible for them to use existing equipment. While Purple Hayes was drilled using a single bit without incident, this result is not guaranteed.

"The thing that was really exceptional about that well is that it was drilled with one drill bit, in one run," said Liberatore. "Technically, everything went perfectly. While there's always room for improvement, there's always the chance that on the next run, you won't get a full 18,000 foot lateral on one run."

Even basic tasks become challenges in superlateral wells. Simply running pipe in such a well is hard on equipment according to DWS technical sales manager Matt Tourigny.

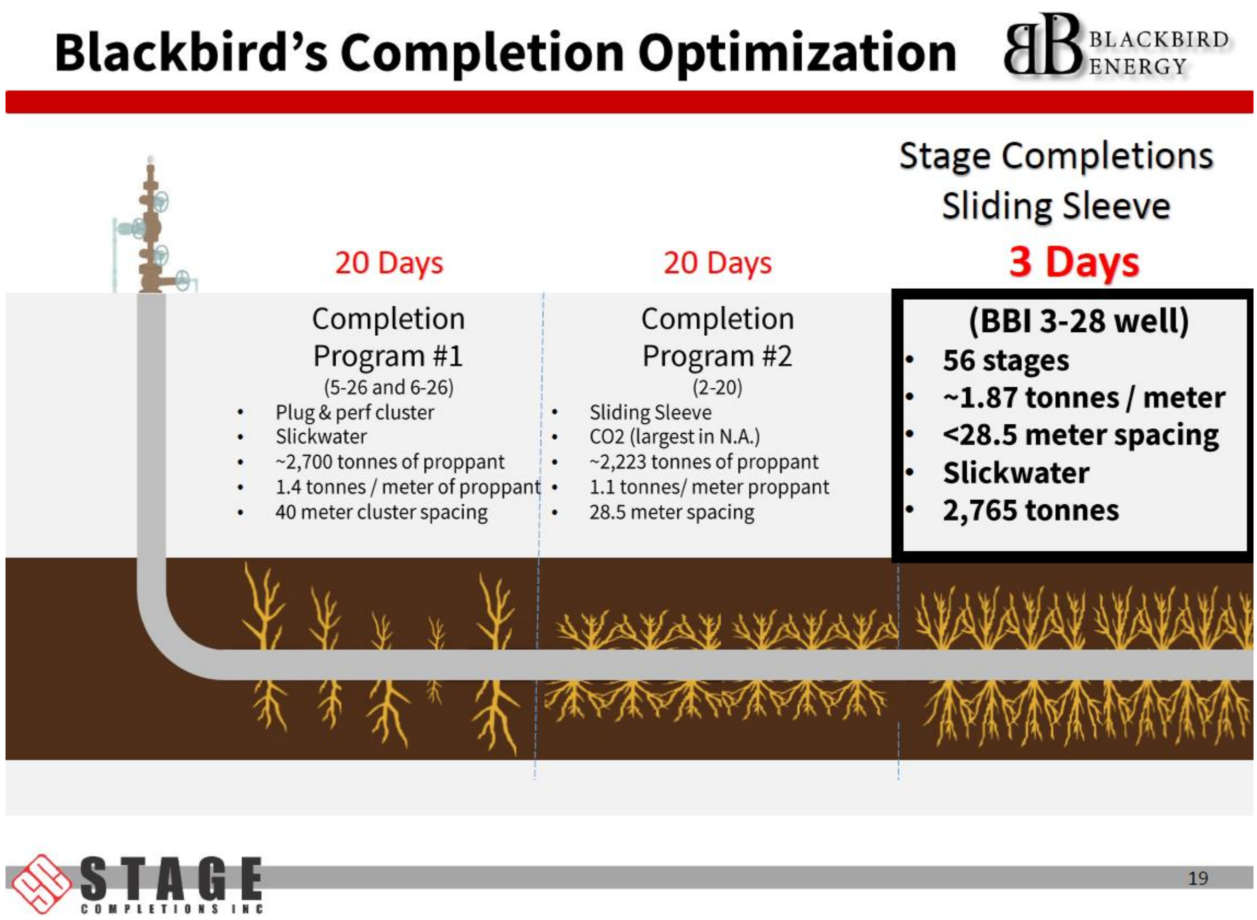
“There’s a lot of heat issues,” he explained. “When you’re running to that length, your snubbing unit is a hydraulic system, and that creates a lot of heat. So one thing we learned half way through the job was to efficiently cool our hydraulic and rotary systems. We were able to cool down the hydraulic fluids and reduce wear and tear on the equipment.”

Service innovation is starting to get traction

Improvements in service technology have moved in incremental steps as horizontal drilling techniques have developed over the last nine years, and that is likely to continue, but several companies are exploring new technologies to improve completions in wells.

During our conference March 1 and 2, Core Laboratories presented both an unconventional enhanced oil recovery (EOR) technology and the company’s HERO PerFRAC, which was designed to create consistent hole sizes throughout the perforating cluster and maximize stimulated reservoir volumes. The unconventional EOR projects run by Core Lab could increase ultimate recoveries in unconventional reservoirs from an average of approximately 9% to as much as 15% based on tests run by the company thus far.

Stage Completions also presented an innovative solution to improve completions. The Stage SC Bowhead II collet-activated fracturing sleeve system reduced drilling stages from 20 days down to 3 in Blackbird Energy’s Montney wells in Canada. The substantial decrease in the number of days required to complete a well despite the increase in length and frac intensity represent a major cost savings for companies using the system, and could ultimately improve ultimate recoveries and well economics in the regions where it is used.



Less than two years ago, the breakeven price needed to make plays economic to drill was well above currently levels. In our June 2015 Monthly Energy Data and Trends, we found that most plays were uneconomic to drill even at $3.81 realized gas prices and $74.34 per barrel of oil for the same plays we examined this month. This significant decrease in the price required by operators to make their drilling economic was driven in large part by innovation from service companies.

At some point, service costs will need to rise in order to continue supporting the health and growth of the E&P industry. If service providers continue to operate on shoestring budgets, they will not have the capital to maintain their current equipment, much less improve the technologies they are using to further enhance ultimate recoveries and completion costs.

Our well economic models currently show that $45 oil would be difficult for all upstream operators, but if service companies are able to continue innovating, it is possible that in another 12 to 18 months that even that threshold would be manageable. This will require further improvements from service companies, however, and that will likely mean they will need to increase prices regardless of where oil prices go in the near-term.

Finding the right balance may mean fewer rigs

Even with improvements to completion technologies, it appears that the demand for more sand and more pumping horsepower are quickly outpacing what is available in the market today. Already, completion dates are starting to get pushed out according to a buyside analyst who spoke with EnerCom. Unless companies have a dedicated frac crew, many are having to wait longer than they expected, sometimes months longer, before completion crews get to their drill-sites.

This will lead to E&P companies bidding up the price of crews and services to ensure that their wells are serviced on time, and will likely add to the upward pressure on service costs. As that happens, however, well economics can quickly decline below 20% IRRs for companies outside the premier basins in the country, particularly if they do not have long-term service contracts. As that happens, companies may decide to pull back on their drilling programs, easing the demand for services, and thus the rate at which prices inflate.

Ultimately this means a stabilizing, or declining, rig count in the U.S. and slower production growth. Less production in the U.S. could go a long way to help oil prices as well, with smaller builds, or even draws, in crude oil inventories boosting commodity prices.

Service cost inflation is important, but oil prices are paramount

While the service sector does play a measurable role in the overall economics in each of the basins we examined, it was oil price in the end that had the greatest effect on IRRs.

At $45 oil, only the Midland Basin can sustain a 13.5% increase to service costs, and none of the basins covered by our well economics models could absorb a 15% increase in service costs. This picture quickly changes as oil prices increase, though, with $50 oil making it possible for the Eagle Ford, Delaware, Midland and Bakken to sustain more than 20% increases in service costs.

The shortage of manpower and equipment could see more E&P companies start to try and outbid one another for completion services, creating more pressure for cost inflation. If increasing availability of services such as completion crews, pressure pumping and frac sand continue to lag behind demand, higher oil prices could potentially translate into further increases in service costs as well. All the analysts we spoke with felt costs would likely trend to the high side of the ranges they had seen, and if the supply and demand balance continues to favor service companies, they may push prices up further.

A Word of Thanks

Thank you again for putting your trust in EnerCom. Please do not hesitate to contact us with questions or additional needs. And, remember that you can get frequent updates and analysis on Oil & Gas 360® at www.OAG360.com

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Energy Industry Data and Trends
Supplemental Slides: Service Costs

March 2017

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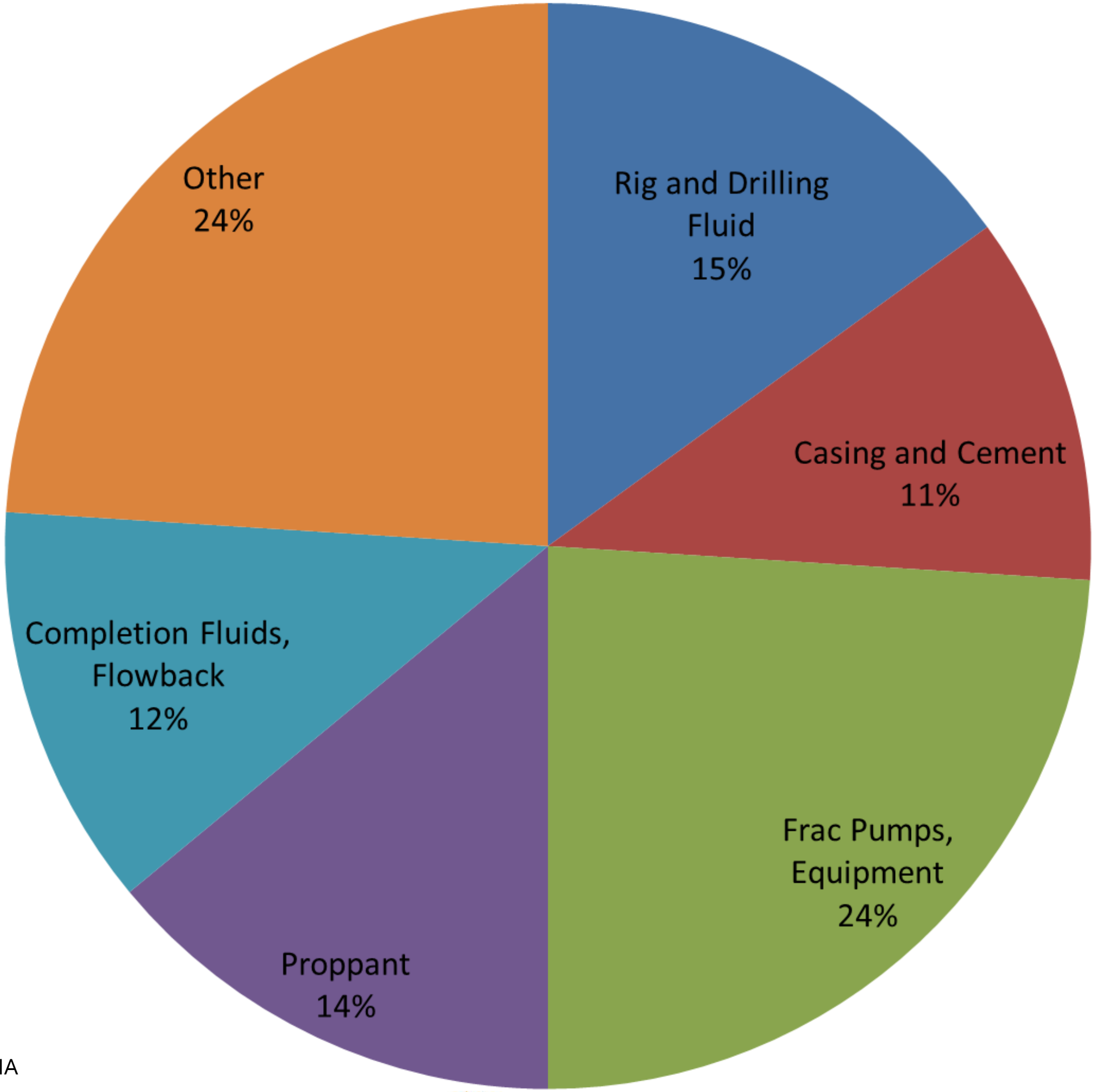
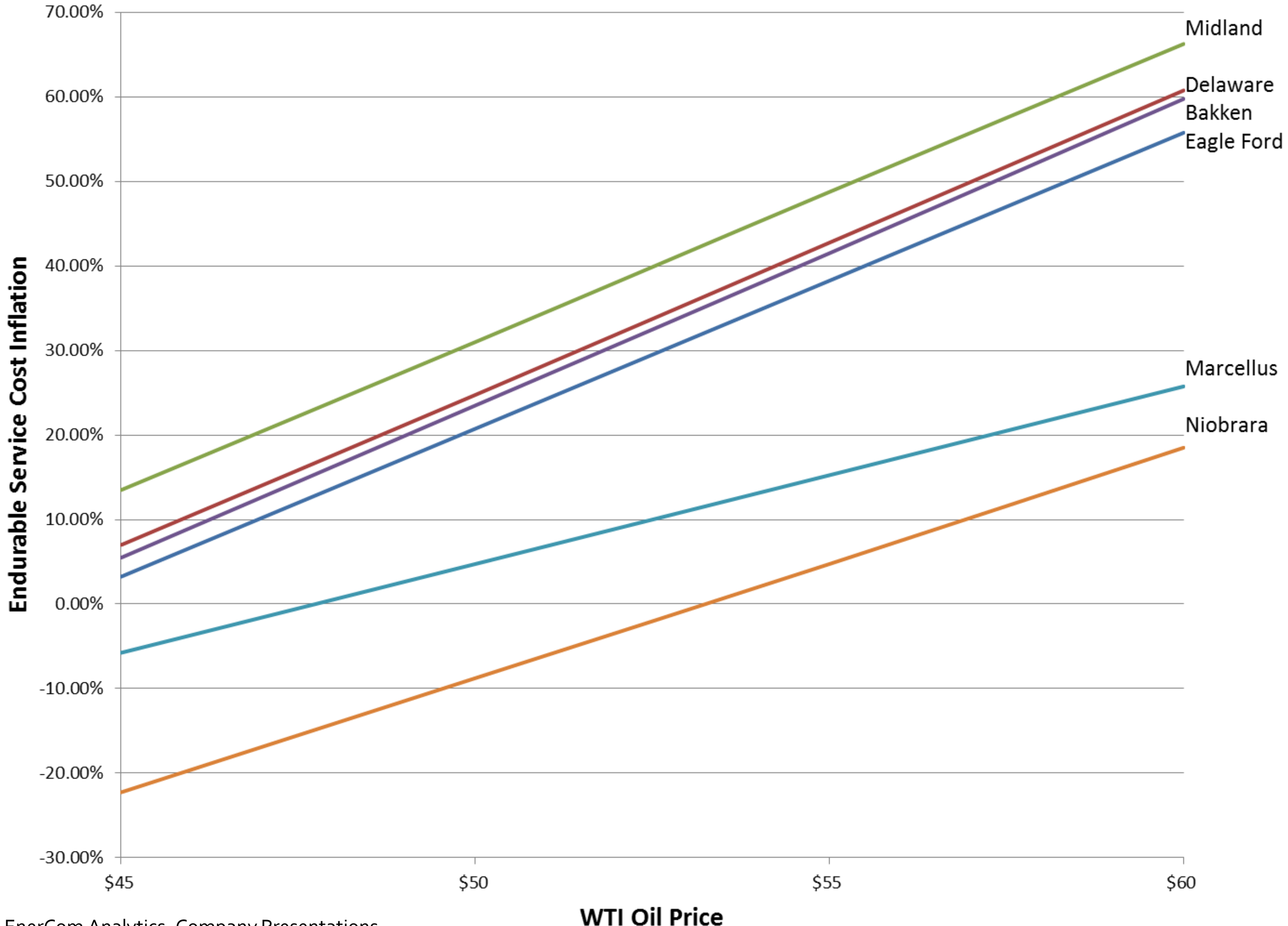
Service Cost Charts

Average Well Cost Breakdown



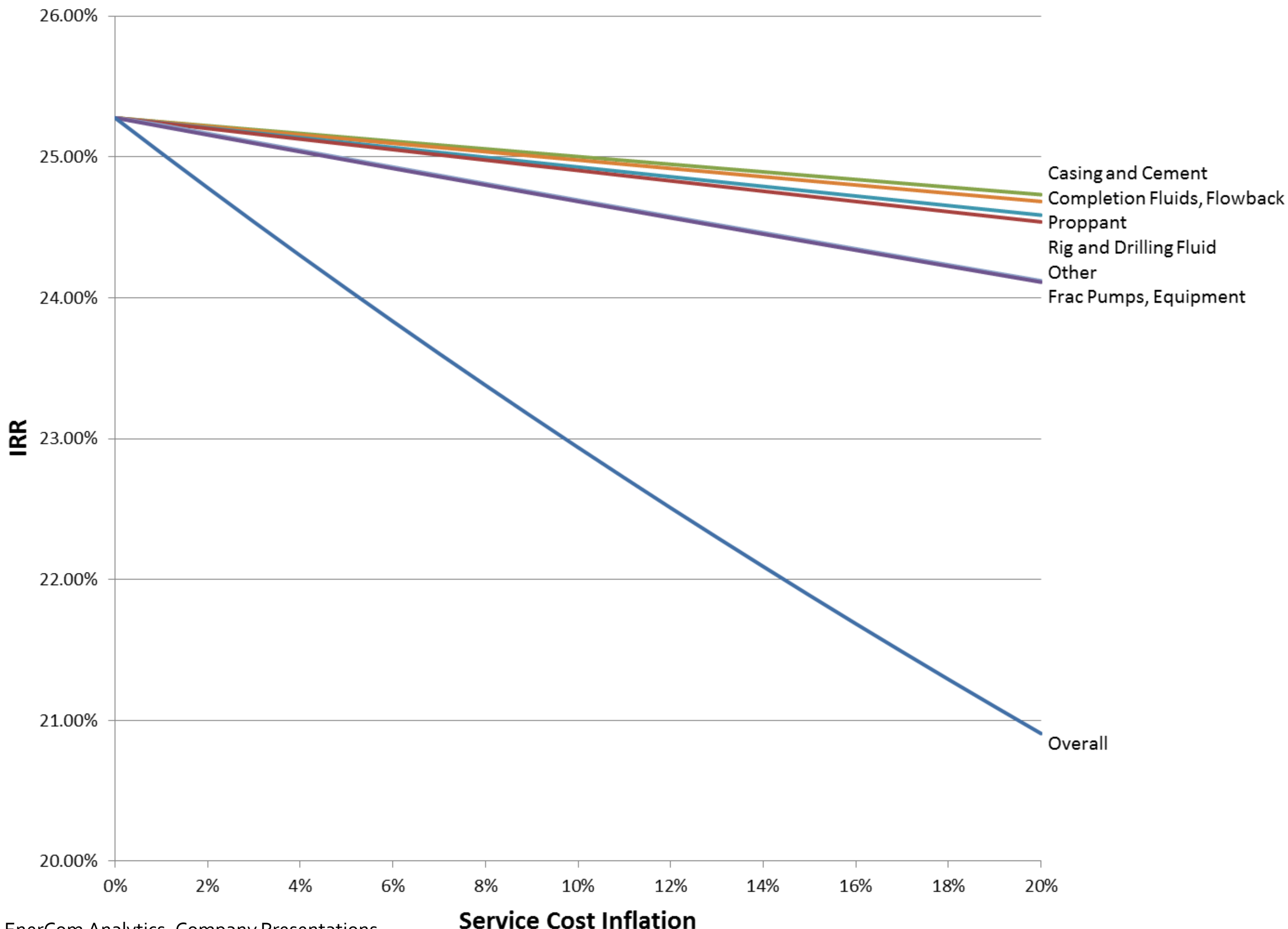
Source: EnerCom Analytics, EIA

Endurable Service Cost Inflation By Basin



Source: EnerCom Analytics, Company Presentations

Service Cost Inflation Effect on IRR in Delaware Basin



Source: EnerCom Analytics, Company Presentations

Economic Model Assumptions and Endurable Service Cost Inflation by Basin

	Midland	Delaware	Eagle Ford	Bakken	Niobrara	Marcellus
Well Cost (Millions)	$6.30	$6.98	$3.88	$6.14	$4.08	$6.96
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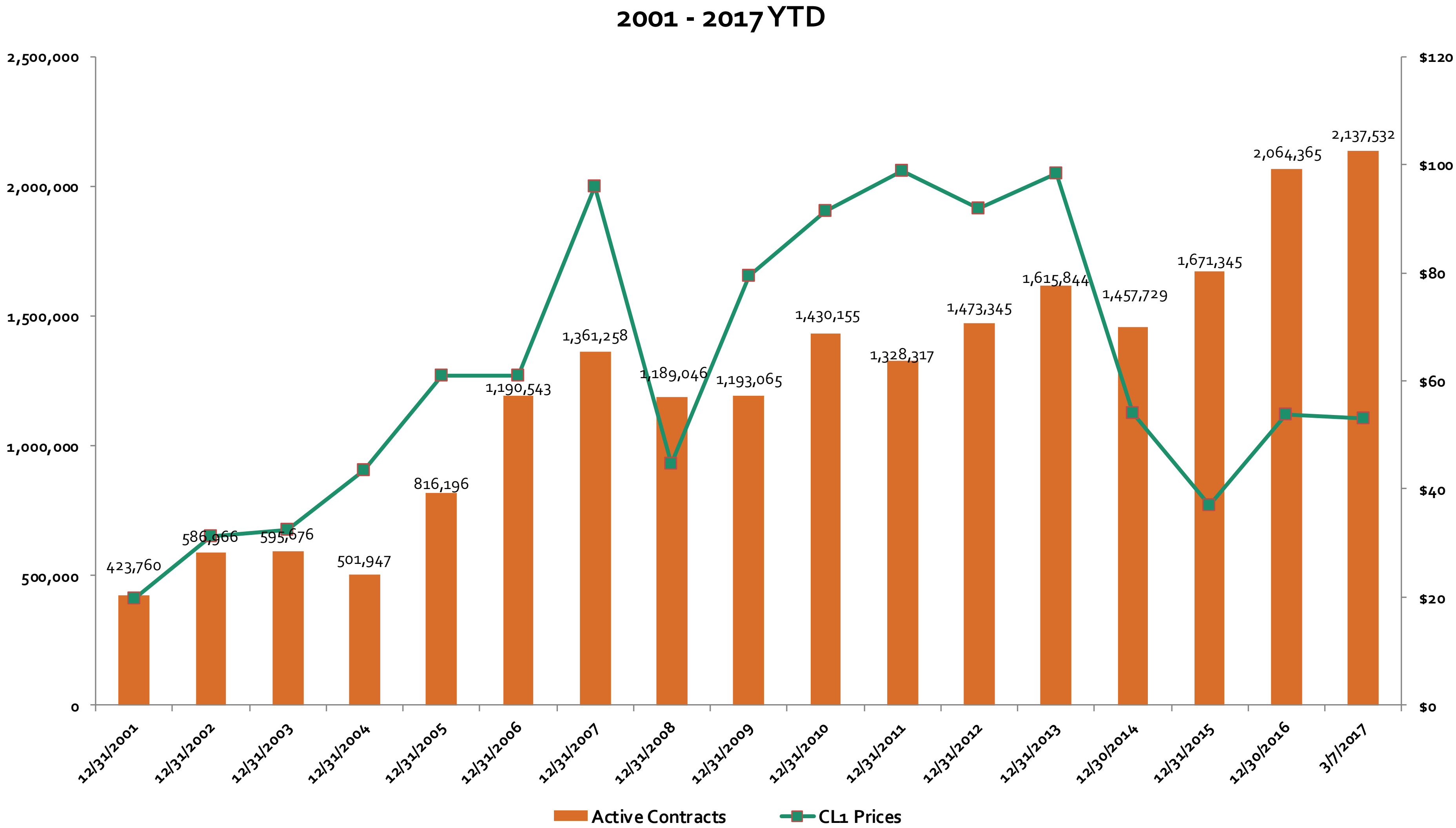
Marcellus	-7.75%	4.75%	17.25%	29.75%

Source: EnerCom Analytics, Company Presentations

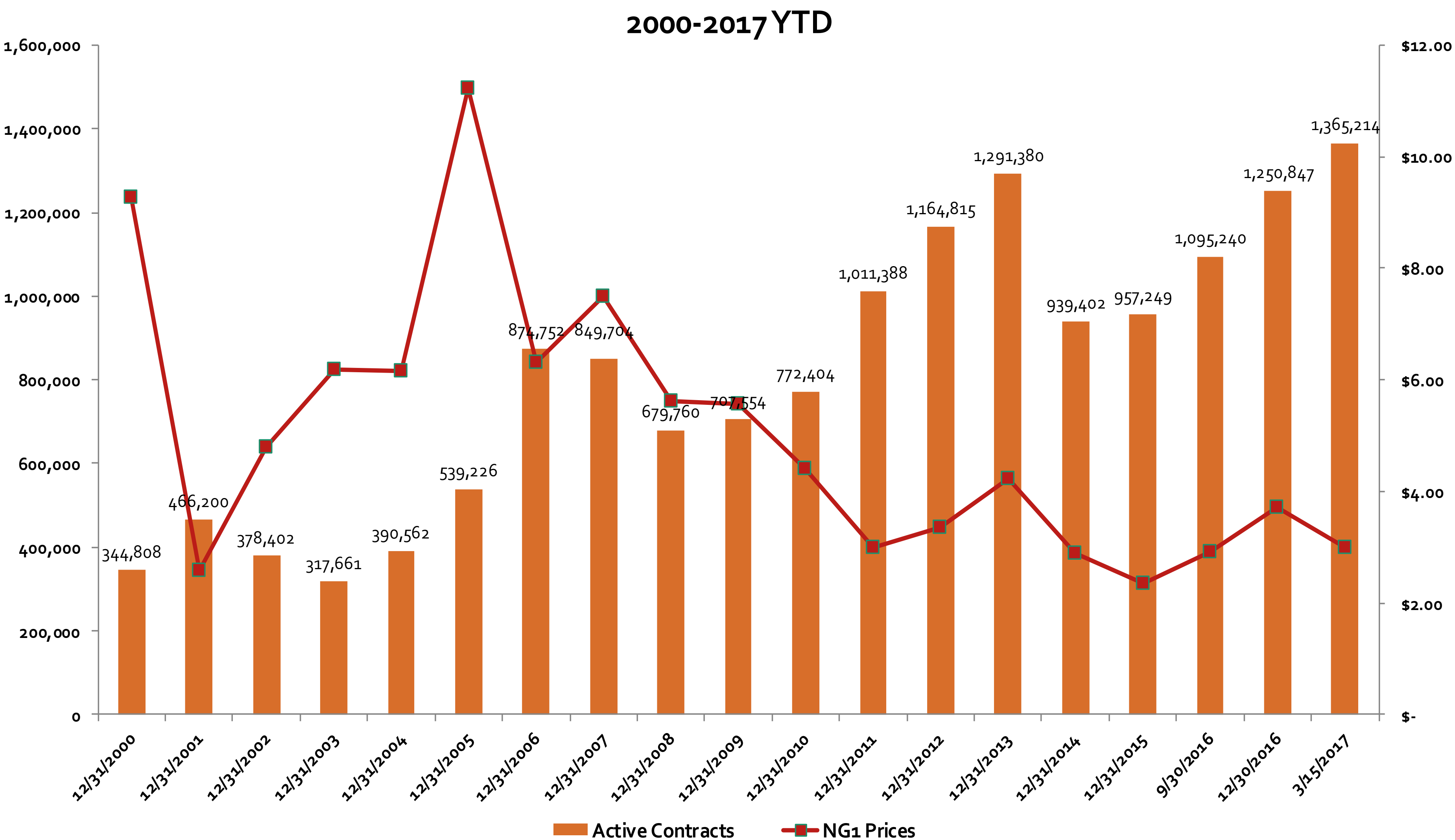
Supplemental Market Slides

Active NYMEX Crude Oil Contracts



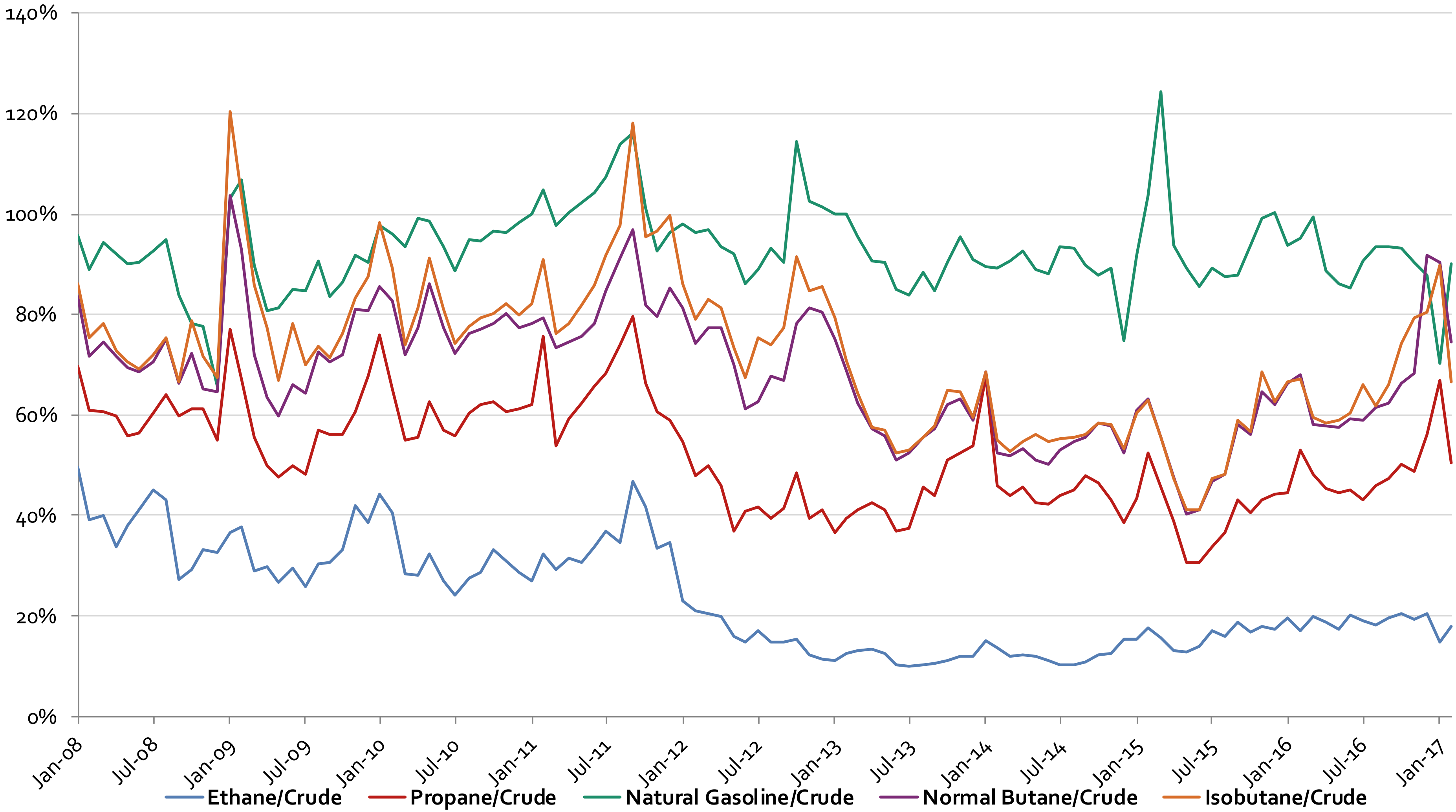
Sources: Bloomberg

Active Natural Gas Contracts



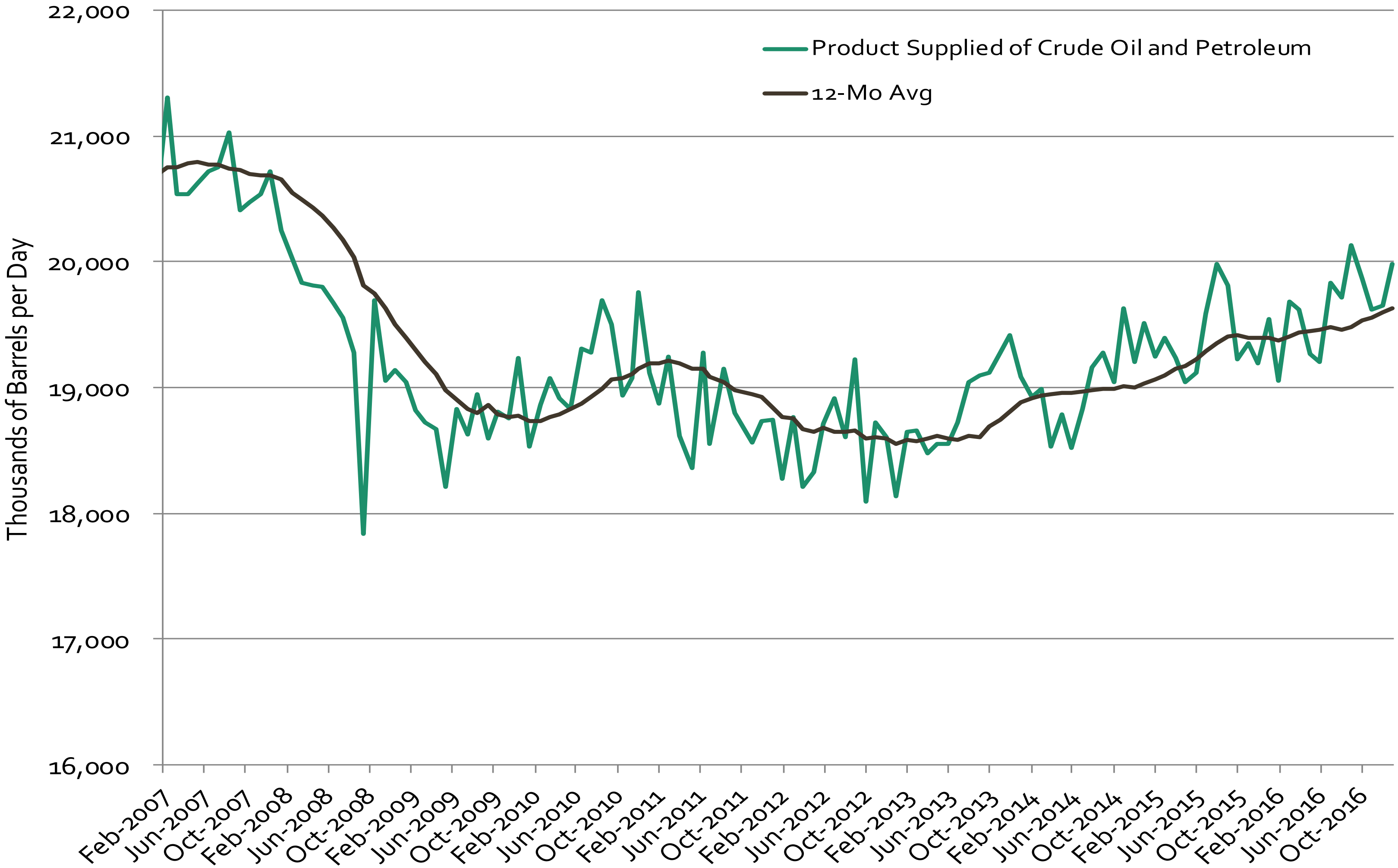
Sources: Bloomberg

Mont Belvieu NGL Prices as a % of WTI



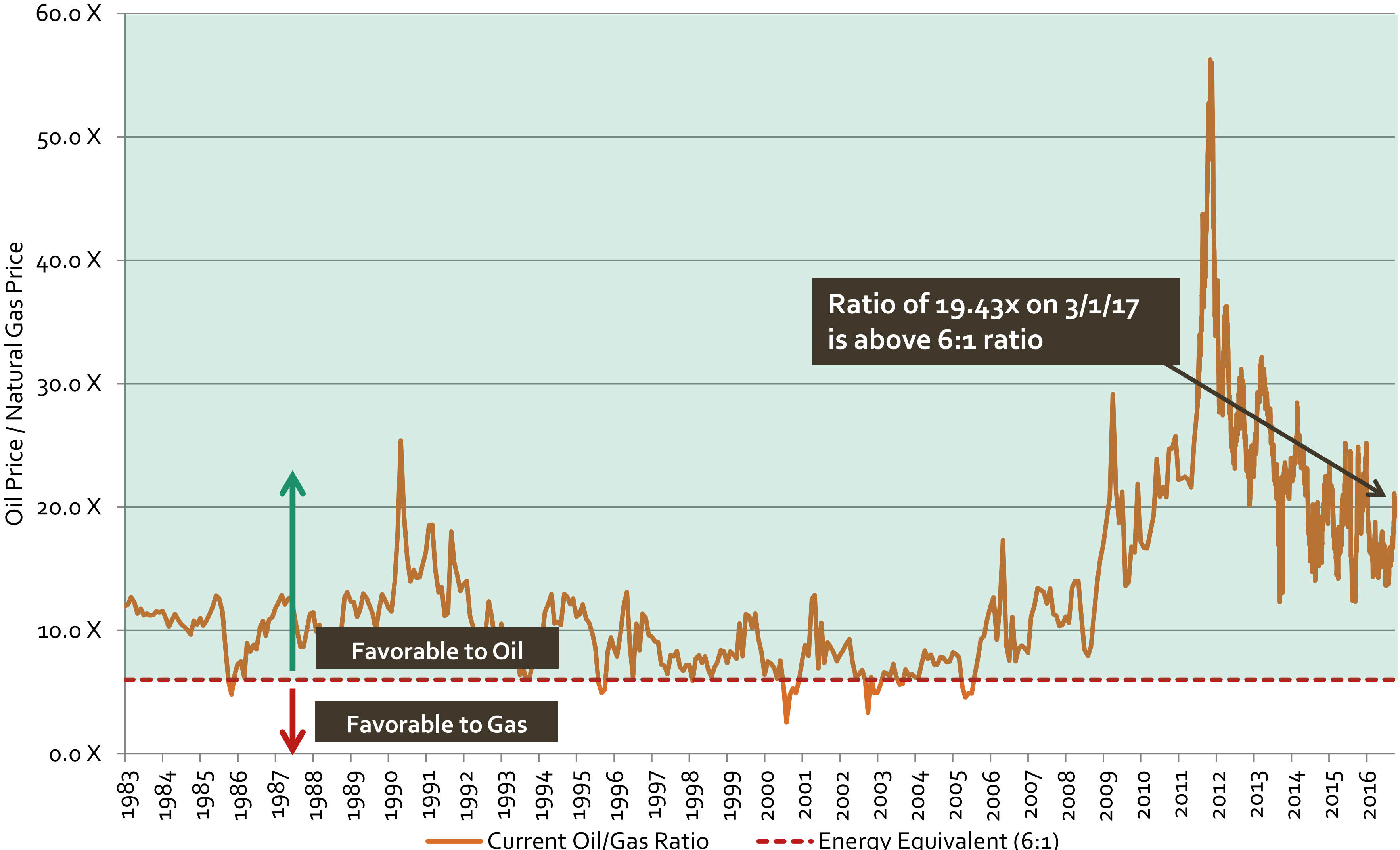
Sources: Bloomberg.

U.S. Oil and Petroleum Product Supplied



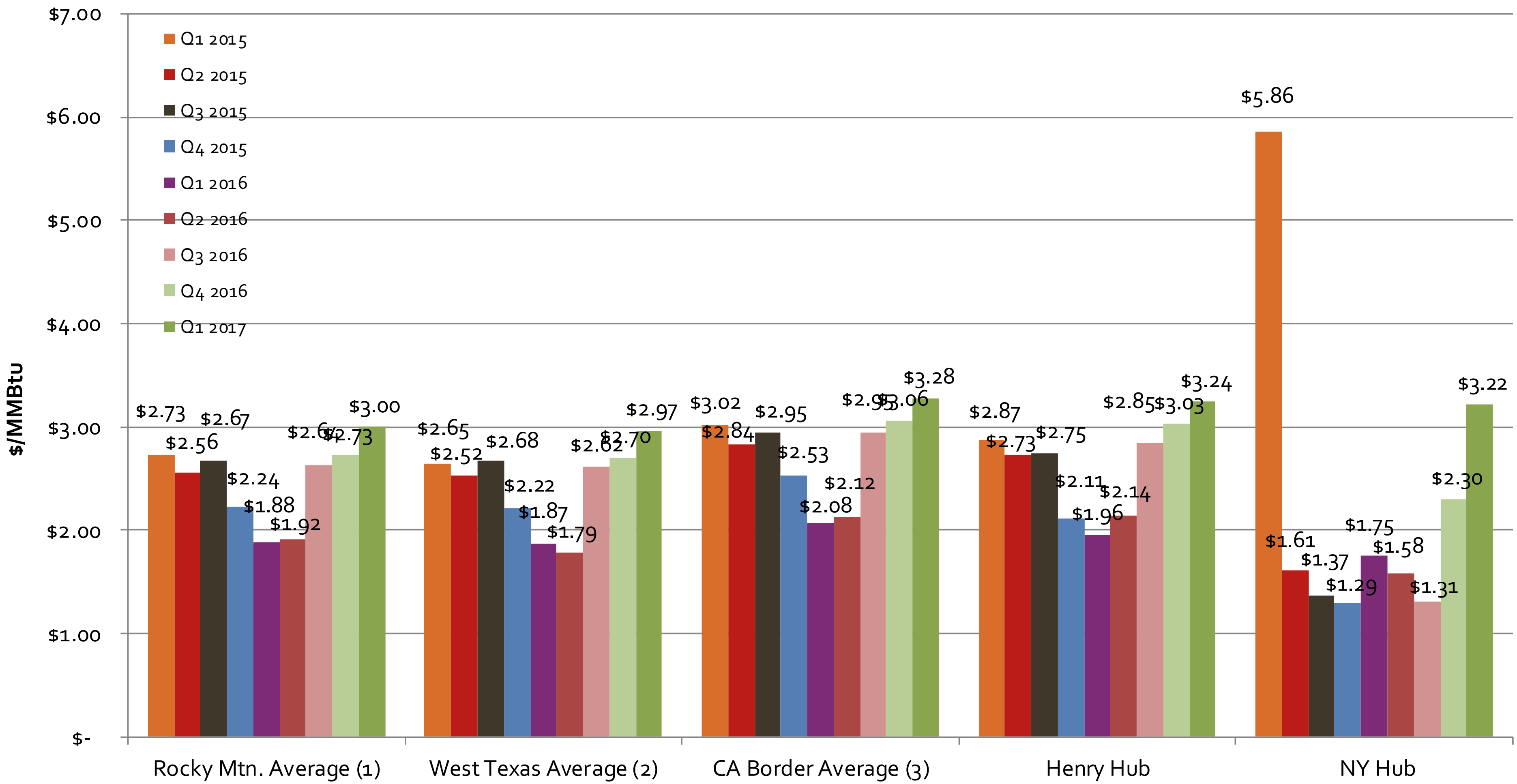
Source: EIA, EnerCom

Energy Equivalent Pricing



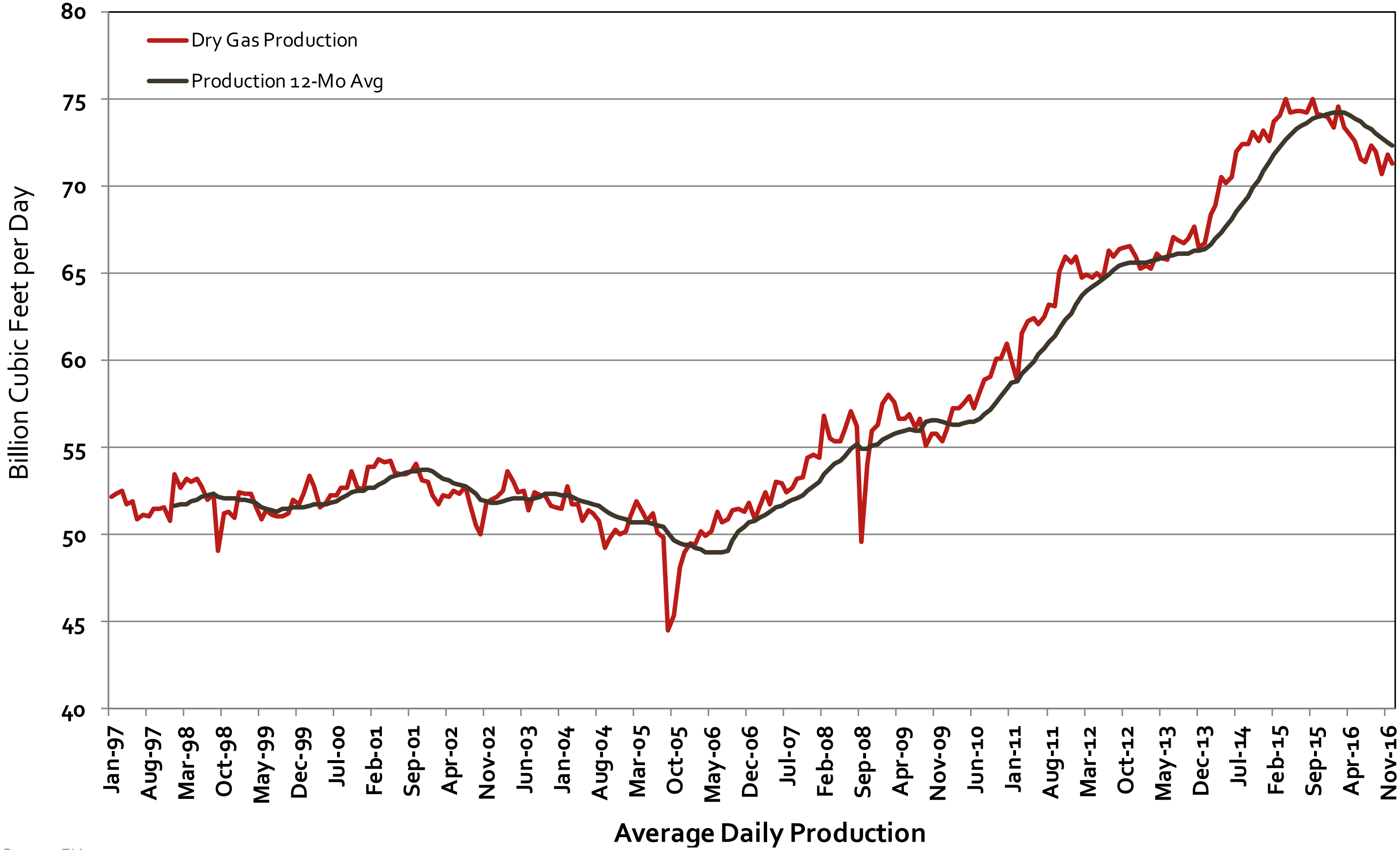
Source: Bloomberg, EIA, EnerCom.

U.S. Regional Natural Gas Prices



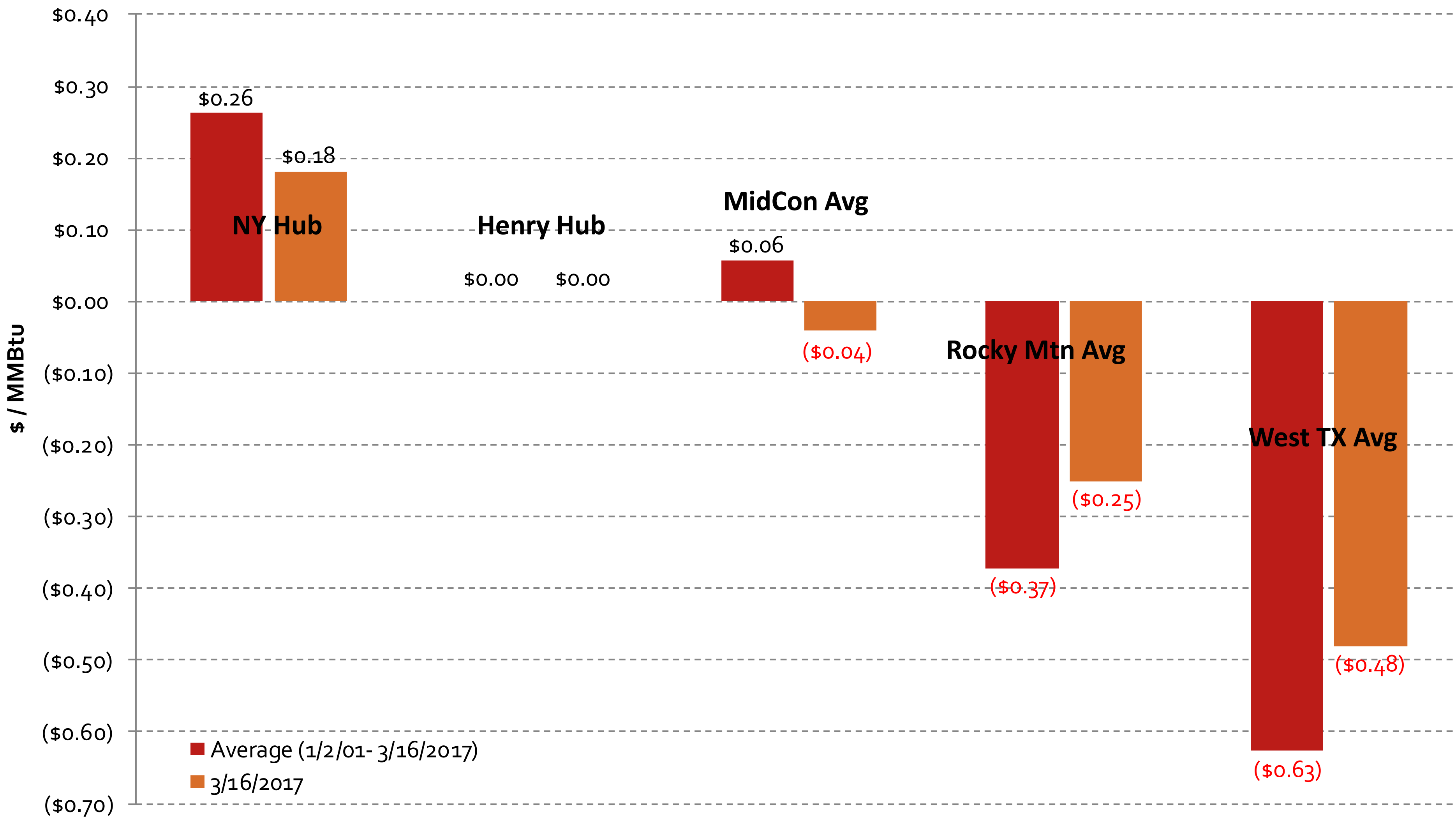
Notes: (1) Average of 3 Rocky Mountain hubs (2) Average of 2 West Texas hubs (3) Average of 3 hubs delivering gas to California border

U.S. Natural Gas Production



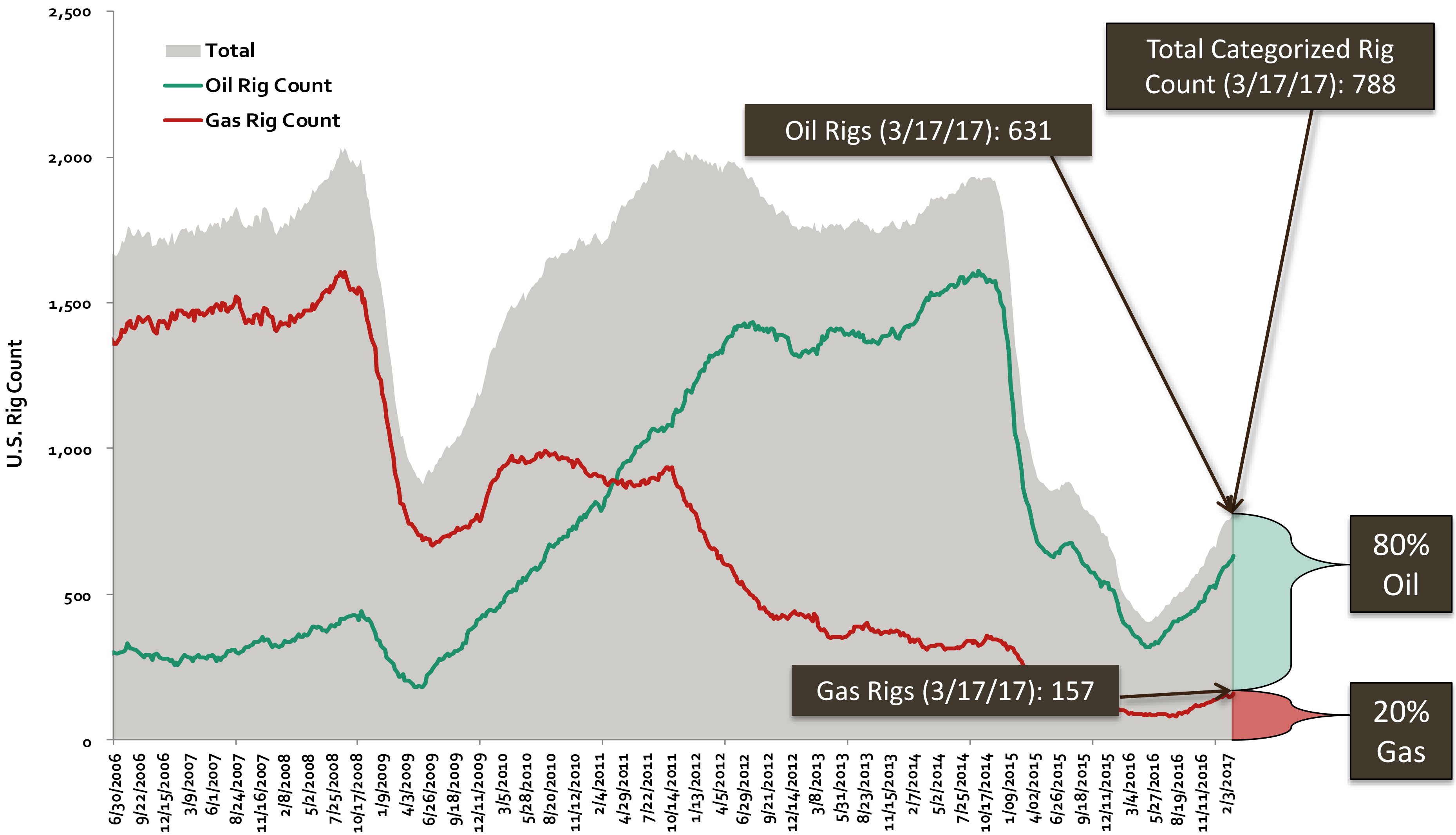
Source: EIA.

Regional Gas Price Differentials



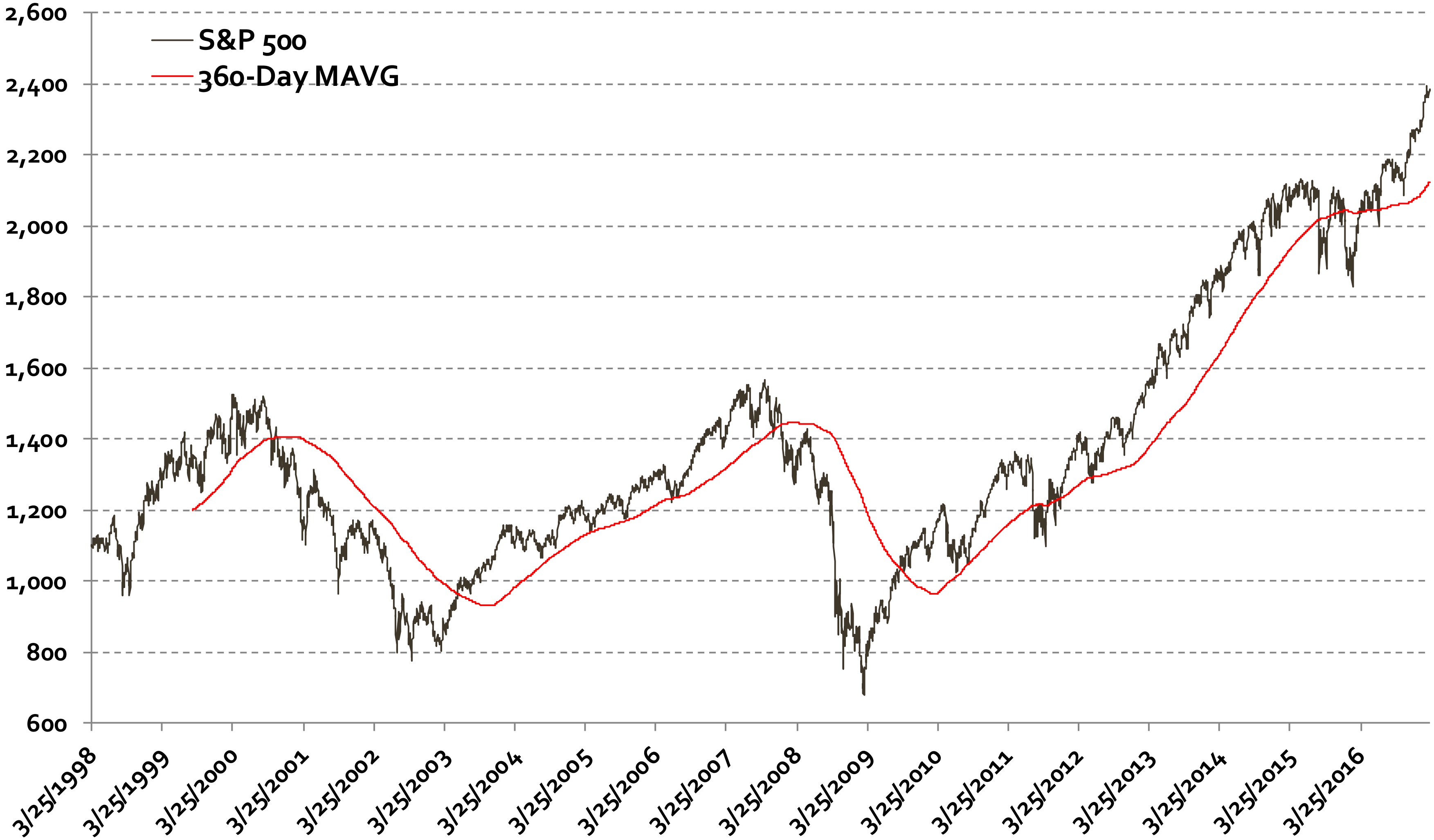
Source: Bloomberg, EnerCom.

Historical U.S. Rig Count (Oil vs. Gas)



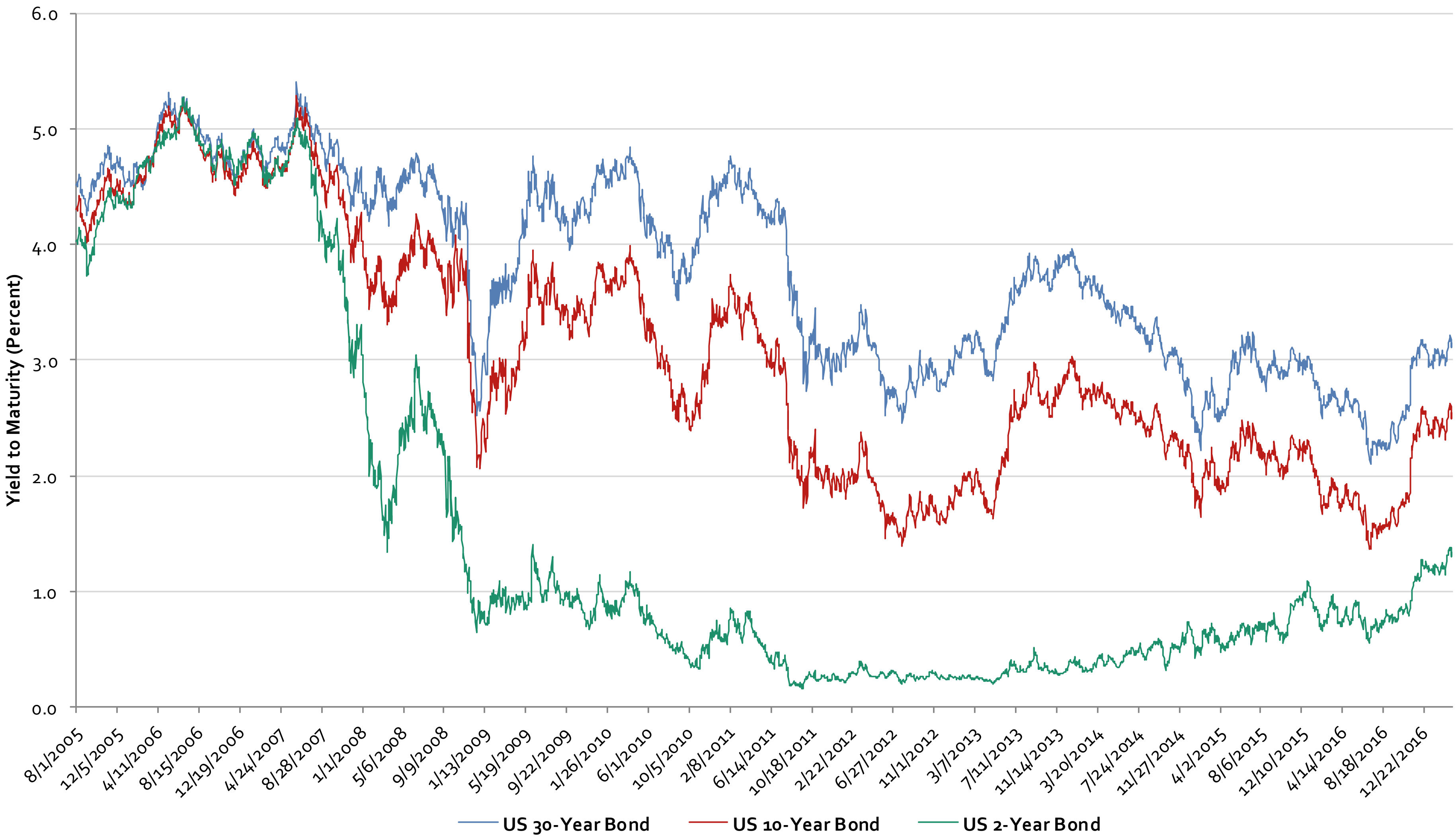
Source: Baker Hughes.

S&P 500 vs. 360-Day MAVG (Long-Term)



Source: Bloomberg.

U.S. Treasury Yields



Energy Industry Data and Trends