It is no secret that the Permian Basin has become the go-to region for companies looking to acquire new acreage. Year-to-date, 38 of the 103 completed M&A deals involved assets in the Permian. That is more than five-times the number of deals done in the Eagle Ford (seven), and more than seven-times the number of deals done in either the Niobrara or SCOOP/STACK in 2017 so far (five deals in each in 2017 YTD).

While there are several sub-basins in the Permian where operators are drilling for impressive results, the Delaware remains the crown jewel of the area. The Delaware, located principally in Reeves and Loving Counties, Texas, has seen a tremendous amount of permitting in 2017. Since the beginning of the year, the Texas Railroad Commission has issued 974 permits in Reeves, representing over 15% of all the permitting this year, and surpasses permitting done in the county in 2014. Loving County comes in third for permitting behind Midland.

Demand to get into the region is unsurprising given the results operators are reporting. Even at $35 WTI wells, all but the most expensive wells drilled in the Delaware remain economic, reflecting internal rates of return of 20% or more.

IN THIS REPORT – Key Summary Points:

- The Permian remains the hottest play in the country with one quarter of all U.S. production coming out of the play in August
- Companies continue to show impressive half-cycle economics on wells in the Delaware
- Several smaller companies are rapidly growing in the Delaware, which is pushing their G&A higher, but we expect they will grow into it
- Wells in the Delaware remain economic even at $40 per barrel oil prices, but wells are becoming more sensitive to changes in service costs
- While the Delaware boasts excellent half-cycle margins, the addition of F&D costs quickly narrows margins, and in some cases, turns companies from a profit to a net loss on a per-BOE basis
- Future development costs are expected to come down from current levels for some Delaware players with high full-cycle costs, which should improve their margins on a forward basis
- Activity in the basin is exceeding 2014 levels even with oil prices at less than half of where they were three years ago
- We believe concerns over potentially gassier wells in the Permian are excessive as the additional BOEs make the wells more economic. The potential implication that operators do not know the resource as well as they thought could give pause to investors, however
PERMIAN PRODUCTION MADE UP ONE QUARTER OF ALL U.S. PRODUCTION IN AUGUST

As a basin, the Permian continues to dominate the overall production of the United States. Last month the basin produced approximately 3,956 MBOEPD of the 15,782 MBOEPD brought up out of the ground across the country. The increased attention of operators in the area has also brought the United States Geological Survey in to do more in-depth studies recently. Following a survey of the Midland Basin, the USGS issued a report stating that the Wolfcamp in the Midland could contain over 20 billion barrels of oil, 16 Tcf of gas and 1.6 billion barrels of NGL alone. While this estimate outlines the technically recoverable oil, not necessarily what is economically available, it is the largest USGS assessment of tight oil resources in any domestic basin and it covers just one bench operators are pursuing in a single sub-basin of the wider Permian.
This massive resource in place has attracted the largest portion of the country’s active rig fleet as well. The rig count for the week ended September 8, 2017 reported 382 rigs active in the Permian, or 41% of the total number of onshore rigs. The rig count in the basin has been steadily rising since a low of 137 rigs in May of 2016.

Although the rig count bottomed out, production in the Permian continued to climb. Improved drilling efficiencies and completions designs allowed new wells brought online to produce significantly more than those drilled prior to the decline of oil prices in late-2014. After adjusting for the increased productivity of modern operations, EnerCom estimates the Permian has an Effective Rig Count of 1,141, compared to a reported rig count of 373. Put another way, the 373 rigs operating in July can produce the equivalent production of 1,141 rigs in the Permian in January, 2014.
The spike in production per rig has taken place against the backdrop of a continued low oil price environment in which operators are being forced to get the most out of each new well. In our August report, we discussed the prevalence of prescriptive completions, or those being custom-designed for individual wells. To better understand how operators are producing more for less and enhancing their completion designs, we looked at several producers in the Delaware Basin including Diamondback Energy, RSP Permian, Jagged Peak Energy, Concho Resources, Resolute Energy, Centennial Resource Development and Parsley Energy.
COSTS AND MARGINS IN THE DELAWARE

U.S. independents have very little control over the price of oil, for better or worse, but operators can control costs to make their business profitable. Companies can control costs by pulling a number of levers including their service contracts, G&A costs and by restructuring debt.

<table>
<thead>
<tr>
<th></th>
<th>OPEX/BOE</th>
<th>G&amp;A/BOE</th>
<th>Interest Expense/BOE</th>
<th>Total Cash Cost/BOE</th>
<th>F&amp;D</th>
<th>Full-Cycle Development/BOE</th>
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</thead>
<tbody>
<tr>
<td>FANG</td>
<td>$6.84</td>
<td>$1.70</td>
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<td>$33.37</td>
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</table>

Source: Company filings, EnerCom Inc.

Looking at the operating costs for our Permian peer group, companies in the basin have low OPEX per BOE. Resolute, on the high-end with an OPEX/BOE of $11.83, is likely seeing the costs of its Aneth field, whose secondary recovery operations require high OPEX but low capital spending. Excluding them from the group, the average OPEX/BOE is $7.31 per BOE.

Interest expense also plays a major role in the total cash cost for several companies in the region. While RSP Permian’s total cash cost on a BOE basis of $14.33 came in slightly above the average of $13.99 per BOE, 27% of that cost came from the company’s interest expense. Parsley Energy also has more than one-fifth of its total cash costs on a BOE basis coming from interest expense, taking it above the average cash cost at $15.85 per BOE.

Two of the companies on the list which are newer to public markets – Jagged Peak and Centennial Resource Development – both have relatively low interest expense, but see a larger portion of their total cash cost coming from G&A. Given that both entered public markets in the last 12 months, JAG and CDEV are both projecting rapid production growth.

CDEV reported year-end 2016 production of 5.8 MBOEPD, with guidance forecasting 24.5 MBOEPD by the end of 2017 when the company first went public last October. In its most recent presentation, the company revised its projections upward, saying it plans to hit 60 MBOEPD by the end of the decade.
Similarly, Jagged Peak is guiding to 221% growth for full-year 2017 at the midpoint of its projections. The rapid expansion both companies are targeting will require staff to help support their activities, and we believe they will likely grow into their higher G&A costs.

Looking at half-cycle returns (total cash costs without finding and development costs) only tells a piece of the story, however. Adding in F&D and looking at full-cycle costs for the peer group quickly changes the overall picture; CDEV goes from the third lowest total cash cost in the group with $11.76 per BOE to the most expensive full-cycle producer at $48.57 per BOE with the inclusion of its $36.81 per BOE F&D cost.

Despite having the highest full-cycle development, Centennial also has the strongest price-to-cash-flow per share multiple in the group at 9.2x.

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<thead>
<tr>
<th></th>
<th>Total Cash Cost/BOE</th>
<th>Full-Cycle Development/BOE</th>
<th>Price/CFPS</th>
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<tr>
<td>PE</td>
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<td>6.3x</td>
</tr>
</tbody>
</table>

Source: Company filings, EnerCom Inc.

The company’s May 1 acquisition of 11,860 acres from GMT Exploration Company in the Northern Delaware acted as the catalyst for CDEV’s upward production guidance revision and is giving the company’s stock a lift as well. With the addition of the GMT assets, CDEV announced that it believes it will achieve a four-year compound annual oil growth rate of approximately 80% through the end of the decade, a very attractive fact for investors who continue to reward healthy growth as we discussed in January.

On the opposite end of the spectrum, Resolute is seeing a lower price/CFPS multiple as the company completes its transition to a Delaware player. It has been able to reduce its debt-to-market cap approximately 50% since the week ended September 9, 2016, but the pending sale of the company’s Aneth
assets and its still relatively high debt-to-market cap of 76% are holding the company back from realizing a valuation similar to other players in the peer group.

**IS THE DELAWARE ECONOMIC AT TODAY’S PRICES?**

The Delaware is constantly touted as the most economic play in the country by those drilling wells there. And looking at our own well economic models, it appears that there is good cause for the hype surrounding the basin.

Wells in the Delaware average approximately $7.3 million based on presentations from companies in the region. Those wells have an average estimated ultimate recovery of approximately 1.2 MMBOE, most of which (average 73%) is liquids. With those metrics, an $8 million well returns 22% IRRs at $40 WTI, giving credence to the economics operators in the region report.
Looking at the peer group’s operation costs and reported revenues, companies in the region have cash margins between 40% and 76%.

Diamondback Energy has both the largest absolute revenue on a BOE-basis at $29.14 as well as the greatest cash margin percentage at 76%. Companies with stronger cash margin percentages were typically the ones with better price/CFPS ratios, but investors are giving a premium to CDEV for projected growth.

Hedges also play an important role in company’s revenue in today’s commodity market. In our February 2016 report, a six-company peer group we analyzed had average realized derivatives of $0.06 per BOE, with a seventh company showing a noticeable outlier of $15.78 per BOE. With oil prices falling from highs over $100 per barrel down to the $40 to $50 range for the last 17 months, companies are now relying more heavily on their hedge books.
The average realized derivatives per BOE among the Delaware peer group was $0.98. Concho Resources is an outlier at $4.05 per BOE, however, and if it is removed from the group, the average drops to $0.47 per BOE. Concho has been able to build a strong hedge position as a result of the company’s significantly larger production base. In the week ended September 8, 2017, the company had trailing-twelve-month production of 311.3 MBOEPD, approximately 2.7x more than the average for the peer group.

A comment we heard from the buy-side following our conference in August was that many companies are highlighting their half-cycle returns, which show impressive IRRs, but are neglecting the realities of full-cycle costs. Looking at the full-cycle costs, which include F&D, the picture becomes much less rosy for Delaware players.

Hedges, therefore, become an increasingly important part of companies’ revenue when looking at full-cycle costs, especially Concho’s outsized $4.05 per BOE. Without it, CXO would be operating at a loss on a full-cycle basis, and even with hedges included, margins are significantly reduced for each company when F&D costs are added.
Jagged Peak’s margins prove to be the most resilient to full-cycle costs, but even they see their margin cut to $15.72 from $28.93, a 45% decrease, once F&D is included in the equation. Diamondback, which had the highest cash margin percent when looking at half-cycle costs, sees its margin cut by 70% to $9.08 per BOE from $29.14 with the inclusion of F&D while Concho and Parsley see their margins cut to single-digits.

Resolute Energy and Centennial Resource Development – the low end and high end, respectively, for the group in terms of price/CFPS -- both have negative full-cycle margins. The costs associated with REN’s Aneth assets is again showing up as a drag on the company’s economics, while CDEV’s historical F&D reflects higher-cost development.
Substituting future development costs for F&D, Centennial will see a $28.46 uplift in their margin moving forward that will more than make up for the full-cycle operating loss that we currently see. It is not surprising that all the companies in the peer group have higher F&D than future development costs given the write-downs many were forced to take during the downturn.
The improved development costs for Resolute also help to close the gap with future development costs bringing the company to a $0.01 loss per BOE. The company’s sale of its Aneth assets (discussed below) will further improve its margins bringing all the companies into positive territory.

Delaware companies can generate strong economics considering projected future development costs, but the returns are still not as strong as the half-cycle results commonly cited in investor presentations.

**RESOLUTE ENERGY SELLS ANETH**

While we were completing our report on the Delaware Basin, Resolute Energy announced that the company has entered a definitive agreement to sell its subsidiary which holds its interests in the Aneth
Field, completing the company’s transformation to a Delaware player. Resolute sold the assets for cash consideration of $160 million with an additional consideration of $35 million possible if oil prices exceed “certain levels” in the next three years, per Resolute’s press release.

Resolute CEO Rick Betz indicated that the proceeds from the sale would be used to pay off the outstanding balance on the company’s revolver, which REN estimates will be approximately $130 to $135 million as of September 30, 2017. The improvements to the company’s balance sheet will position it such that the company can focus on future growth in the Delaware.

The deal also reduces the company’s LOE significantly. In its Q2 report, Resolute stated LOE for the company was $8.97 per BOE; with the sale of its Aneth assets, Resolute’s LOE will be reduced 46% on a BOE basis to $4.87 per BOE, bringing the company in line with its Delaware peers on OPEX. We expect that OPEX would be higher than $4.87 per BOE after adding in production taxes and other items excluded from the company’s LOE, but the cost reduction from the asset sale will have a positive impact on the company’s margin.

Resolute’s production will be impacted by the sale, but given the strengthened balance sheet and greatly reduced production costs, markets are viewing the news as a plus for the company. Per the company’s press release, its Permian Basin assets produced 23.6 MBOEPD in July out of a total 29.5 MBOEPD for the company.
Markets did not seem to mind the trade off, with REN’s stock rising 9% from the opening bell on Thursday, September 14, to close on Monday, September 18, 2017. Prior to the announcement, the company was underperforming the XOI, but quickly surpassed the XOI following the news. Investors continue to pay a premium for Delaware players, and Resolute’s execution on the Aneth divestiture payed off for the company.

**DELAWARE ACTIVITY EXCEEDING 2014 LEVELS**

Along with strong economics of the play has come a rush of activity that is beyond levels seen even when oil prices were in the triple-digits. Permitting activity in the Delaware Basin is tremendously popular as companies attempt to secure drilling rights. Per the Texas Railroad Commission, the six counties that make
up the Texas portion of the Delaware - Culberson, Loving, Pecos, Reeves, Ward and Winkler - have had nearly 2,500 drilling permits approved in 2017 to date.

Virtually every Permian county saw permitting activity fall in 2014, as diving oil prices squeezed producers. However, some locations in the Delaware have seen activity surpass the highs of $100/bbl oil. The downturn was less pronounced in Reeves and Loving Counties. The strong economics in the basin kept permitting close to 2012 and 2013 levels even as prices dropped.

Reeves County is the heart of modern Delaware operations, with 974 approved permits in 2017 so far. Nearly 40% of all current Delaware permitting activity focuses on Reeves, compared to less than one-third in 2014. Activity this year has already surpassed the previous 2014 high of 769 permits, with the year only
partially complete. Should permitting continue at current rates, it is possible over 1,460 permits could be approved in Reeves County this year, exceeding permitting activity in any single county in 2014.

The story is similar in four of the five other Delaware Counties; permitting activity this year is projected to exceed the highs of 2014, and in some cases already has. Loving County, the second-most popular Delaware basin, has already seen 572 permits approved in 2017, exceeding the 493 permits approved in 2014. Reeves and Loving Counties represent a combined 62% of all Delaware permitting activity in 2017, while Ward, Pecos, Culberson and Winkler Counties represent 11.6%, 10.6%, 8.0% and 7.5%, respectively.
Among the companies in the peer group, Centennial is the most active in the Delaware. The company is totally focused on Reeves County, with 100 drilling permits approved this year. Resolute is similarly focused, with all the company’s 36 permits located in Reeves County. Jagged Peak has spread its activity over the largest area with permits in Reeves, Ward, Pecos and Winkler Counties. Unlike overall Delaware activity, companies in the peer group have relatively few operations in Loving County.
Overall in the Delaware, Anadarko dominates with more than double the approved permits of the second most active operator. With 181 approved permits in Loving County, Anadarko represents nearly one-third of all permitting activity in the county. The company also has 98 permits approved in both Reeves and Ward Counties, placing it among the top companies in both areas. EOG ranks second in permitting activity, with 136 permits approved so far in Loving and Reeves Counties. Apache has the third-highest amount of Delaware permitting activity, focusing on Reeves County. A total of 132 companies have received Delaware Basin drilling permits this year.
Despite its large production base compared to the peer group, Concho is the 12th-most active operator in the region in terms of permitting. The smaller companies that are looking to quickly grow production such as Centennial, Parsley and Jagged Peak all have more permits submitted this year than CXO.

**CONCERNS ABOUT GASSY WELLS ARE OVERBLOWN**

During the Pioneer Natural Resources' second-quarter conference call, the company announced that its wells in the Permian are producing more natural gas than the company previously anticipated, and that the company would defer 30 completions in the region. The news sent the company’s stock price to $135.12 from $163.27 the day before its call, a 17% drop. Looking at the company’s stock price indexed to the wider XOI Energy Index before and after the call, it is clear that this news acted as a catalyst for the company’s lower stock price.
Pioneer was performing in line with the wider XOI E&P index leading up to its conference call, but saw its stock drop significantly on August 2 (the day of its Q2 call), and even further the following day as news spread markets digested the implications. The XOI remain relatively unchanged over the same period indicating the event was isolated to Pioneer and not the macro environment.

Leading up to our August conference, buy side investors told us they were waiting for Q2 results to gauge how much activity there might be from the investment community, but that the Pioneer news was the equivalent of the groundhog seeing its shadow, with the news signaling that the downturn could continue. While the delayed completions are undesirable news for the company, Pioneers gassier wells are not a negative in our opinion.
The company is reporting crude results that are in line with expectations, so every additional BOE of gas coming out of their wells is making them more economic than previously forecast. While the wells were drilled on Pioneer’s Midland acreage, there is concern that the issue will be basin-wide, and other companies are reporting similar results in the Delaware.

The natural gas component of Delaware wells is essential to their economics in our well models. At $47 WTI and no revenue coming from produced gas, the wells fall into uneconomic territory with IRRs of approximately 17.2% compared to 21.1% if operators receive $2.50 per Mcf of gas.

Increasing the amount of gas in the well will change the GOR, but it also increases the EUR and flatten out the well’s overall decline curve. The wells are remaining oil-weighted as well, and even if reduce the gas decline in our well models to 65% in the first year and give gas production the benefit of declining more
slowly than oil, the effect is a 1% to 2% increase in the well’s IRR. While this is a small move in the well’s overall economics, it is still a move in a positive direction.

Perhaps more interesting is what the gassier wells say about our understanding of the reservoir itself. While we view the increased gas production as a positive from an economics standpoint, it does indicate that there is still more to be learned about the actual resource in place.

**SERVICE COST SENSITIVITY IS INCREASING**

Service costs remain on the minds of investors as they wait for the service industry to push back on E&Ps after years of cutting costs. As early as the second quarter of 2016, major service providers such as Halliburton were discussing the need for higher service costs to maintain a healthy oilfield service sector. In our March report, we explored how much of a service cost increase each of the basins could withstand and found that the Delaware could withstand more than the expected increases at $50 oil, but the picture changed quickly depending on the price of WTI.

Even though well costs in the basin have gone down since our Q1 analysis, the basin has become more sensitive to service cost increases. In March, our models showed that the Delaware could withstand a 7% increase in service costs and still support IRRs of 20% or greater at $45 WTI and $2.50 NYMEX natural gas. With the Q2 updates, our well economic models for the basin show Delaware wells returning 19.7% IRRs at flat service costs.

As with our March report, the price of oil remains the single largest factor in how much service cost inflation wells can withstand in the region. Year-to-date, WTI has averaged $49.40 per barrel while NYMEX has averaged $3.06 per Mcf. Using these price assumptions in our model, the Delaware remains resilient to service cost inflation with wells generating 20% IRRs or better with as much as a 17% increase on service costs. Most operators with which we have spoken indicated that they expect service costs to increase between 10% and 15%, meaning Delaware wells will remain economic if prices remain at or above their year-to-date averages, but the increased sensitivity to changes in service costs is noteworthy.

Sand for high-intensity fracs remains one of the key components of the service side cost equation for operators in the region, and companies continue to look for ways to lower costs through locally-sourced sand. During Jagged Peak’s Q2 conference call, the company fielded questions on service costs, and JAG CEO Joseph Jaggers said inflation should not be a major concern.
“We do have plans around local sand out there and that’s obviously going to save us quite a bit of money on transportation. But our rigs are locked down,” he said. “So I don’t see that being an element of inflation. Generally, we haven’t seen a large increase in cost out here and don’t anticipate [any] going forward. I think the fact that we were active in this are through the downturn and we established some long-term relationships, contractual and otherwise, with suppliers out here has effectively insulated us from a lot of this.”

Service companies are also looking for ways to best serve operators in the Delaware with an increased push toward locally-sourced sand. Hi-Crush recently opened its in-basin sand mine in Kermit, Texas, which the company expects will provide 3 million tons per annum of sand to operations in the Delaware and Midland basins all by truck.

E&P and service companies are forward-thinking and are finding ways to keep costs down even as the economics in the play become more heavily affected by the service side of the equation. According to Credit Suisse, 32 million tons per year of additional capacity could come online by the end of 2018 from Texas mines.

While most Texas frac sand is not as high quality as Northern White, it can be significantly less expensive to produce. Companies seem willing to accept lower quality sand if it is both cheap and immediately available. A west Texas sand company can produce and deliver sand for around $40/ton, or about half the cost of sand from Wisconsin and Minnesota.

The growth in Texas production is coming online much sooner than expected, based on recent permitting activity. Previous projections expected the sand industry to take three or four years to build enough sand capacity to serve the Permian in Texas. But companies’ announcements suggest that this could happen in 2019, only two years after the current resurgence began.

**FULL-CYCLE MARGINS WILL BE THE ULTIMATE TEST**

The Permian remains the most active basin in the country, and for good reason; its sub-basins such as the Delaware offer some of the strongest economics anywhere. Companies operating in the Delaware continue
to push down the cost of wells while increasing their ultimate recoveries. The net effect has been desirable economics that have encouraged a rush of activity in the basin.

Increased demand to enter the Delaware has been accompanied by significantly higher land costs, however, which are putting strain on companies to prove the viability of new benches in the play as we noted in our August report. Taking into account the full-cycle costs of the play, companies’ margins shrink rapidly with some seeing net losses based on current prices and well cost assumptions.

For some of the new players looking to increase the size of their operations rapidly – CDEV in particular – future development costs are expected to come down from levels which are eliminating full-cycle cash margins. Those with large, established production bases, such as Concho, are instead relying on the scale of their operations and using hedges to keep them in the black.

Investors continue to give strong preference to companies operating in the Delaware as well. Excluding Resolute, which is trading as though it were outside the basin, the average price/CFPS for the peer group we examined is 7.3x, compared to an average of 4.2x for all the companies in our E&P universe. There has been some concern in the investment community since Pioneer’s Q2 call about the gassiness of the company’s Permian wells, but we view the increased EURs as a positive. What might be giving investors pause, however, is what the changing GOR says about the industry’s overall understanding – or lack thereof - of the play.

Activity in the Delaware has ramped up considerably from 2014, and while there may be the occasional misstep, the industry continues to learn the ins and outs of the play. For the time being, investors seem willing to take that risk, but companies will need to continue to execute to retain their premium multiples. Already, several E&P and midstream companies have signaled that they feel there are better deals to be made where the acreage is not as hot. As we saw in our February report, markets are willing to reward companies for making good deals outside the Permian, as was illustrated by Sanchez’s 50% outperformance of the XOI index following its Eagle Ford acquisition.

Investors are confident companies will continue to drive the marginal cost of production down and it is now a question of timing. The results companies are reporting in the Delaware are compelling, but investors ultimately want to know if the acreage will be economic on a full-cycle basis. Continued activity in the area will inexorably flesh this out, but our models suggest margins will be thin for most operators once full-cycle costs are considered.
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
<table>
<thead>
<tr>
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<tr>
<td>Delaware Basin Study Slides</td>
<td>3</td>
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<tr>
<td>Supplemental Market Slides</td>
<td>19</td>
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EnerCom’s Delaware Basin Study
USGS U.S. Oil Resource Map

Mean Continuous Oil Resources
(Undiscovered, Technically Recoverable Resources)

Mean total: 33 BBO
(Billions of Barrels of Oil)

Source: USGS
Permian Basin Rig Count and Production

Source: EIA, Baker Hughes Industries, EnerCom Inc.
EnerCom Delaware IRR Sensitivities

Source: Company filings, EnerCom Inc.
Delaware Costs and Margin

Source: Company filings, EnerCom Inc.
Delaware Full-Cycle Costs and Margin

Source: Company filings, EnerCom Inc.
Delaware Peer Group Cost and Future Development Margin

Source: Company filings, EnerCom Inc.
Delaware F&D vs Future Development Costs

Source: Company filings, EnerCom Inc.
Source: Company filings, EnerCom Inc.
Cumulative Permitting by County in the Delaware Basin

Source: Texas Railroad Commission, EnerCom Inc.
Permitting by County in the Delaware Basin by Basin

Source: Texas Railroad Commission, EnerCom Inc.
The Counties of the Delaware Basin

2017E Permits by County
- More than 1,400
- More than 800
- More than 400
- More than 200

Source: Texas Railroad Commission, EnerCom Inc.
YTD Delaware Permitting by County

Source: Texas Railroad Commission, EnerCom Inc.
YTD Delaware Permitting in Peer Group

Source: Texas Railroad Commission, EnerCom Inc.
YTD Delaware Permitting by Company

Source: Texas Railroad Commission, EnerCom Inc.
PXD Stock Performance July 27 to Aug 4

Source: Texas Railroad Commission, EnerCom Inc.
Supplemental Market Slides
In 2016, Companies Raised More Than $110 Billion in Capital

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<tr>
<td>Initial Public Offerings</td>
<td>$5,710MM</td>
<td>$6,670MM</td>
<td>$8,210MM</td>
<td>$1,390MM</td>
<td>$3,230MM</td>
<td>$2,250MM</td>
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<tr>
<td>Follow-on Offerings</td>
<td>$18,350MM</td>
<td>$20,260MM</td>
<td>$22,380MM</td>
<td>$24,540MM</td>
<td>$42,330MM</td>
<td>$14,540MM</td>
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<td>Debt Offerings</td>
<td>$78,634MM</td>
<td>$53,783MM</td>
<td>$73,586MM</td>
<td>$107,155MM</td>
<td>$64,634MM</td>
<td>$42,280MM</td>
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<tr>
<td>Totals</td>
<td>$102,694MM</td>
<td>$80,713MM</td>
<td>$104,176 MM</td>
<td>$133,085MM</td>
<td>$110,194MM</td>
<td>$59,070MM</td>
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<tbody>
<tr>
<td>$220B/865 deals</td>
<td>$264B/1040 deals</td>
<td>$102.9B/492 deals</td>
<td>$135.5B/549 deals</td>
<td>$107.7B/421 deals</td>
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<tr>
<td>$319B/1,326 deals</td>
<td>$215B/1,303 deals</td>
<td>$373B/1,694 deals</td>
<td>$305.1B/1,021 deals</td>
<td>$286.4B/1,078 deals</td>
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</table>

Source: Bloomberg, EnerCom Inc.
Drilled, Completed, and DUC Wells

Source: EIA, Baker Hughes Industries, EnerCom Inc.
Total U.S. Sand Demand

Source: Credit Suisse
S&P 500 vs. 360-Day MAVG (Long-Term)

Source: Bloomberg.
Key Basins Driving Oil Production Growth

Texas and North Dakota Crude Oil Production

- Permian and Eagle Ford
- Bakken and Three Forks

Source: EIA.

WWW.ENERCOMINC.COM
U.S. Oil and Petroleum Product Supplied

Jun-17 U.S. oil demand was up 2.3% from May-17 and up 3.5% from Jun-16

Source: EIA, EnerCom
Energy Equivalent Pricing

Source: Bloomberg, EIA, EnerCom.

Ratio of 15.8x on 9/15/17 is above 6:1 ratio

Favorable to Oil
Favorable to Gas

WWW.ENERCOMINC.COM
Active NYMEX Crude Oil Contracts

2001 - 2017 YTD

Sources: Bloomberg
Oil Prices – WTI and Brent

Source: Bloomberg.
U.S. Natural Gas Production

Average daily production in the Lower 48 was up 1.95% in February 2017 from January 2016 and down 3.38% from February 2016.

Source: EIA.
U.S. Natural Gas Consumption

YTD June 2017 Natural Gas Consumption -5.2% over 2016

Source: EIA and EnerCom.
Active Natural Gas Contracts

2000-2017 YTD

Sources: Bloomberg
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<tbody>
<tr>
<td>Rocky Mtn.</td>
<td>$2.73</td>
<td>$2.65</td>
<td>$3.02</td>
<td>$2.87</td>
<td>$5.86</td>
<td>$2.56</td>
<td>$2.52</td>
<td>$2.84</td>
<td>$2.73</td>
<td>$1.61</td>
<td>$2.67</td>
<td>$2.68</td>
<td>$2.95</td>
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<tr>
<td>West Texas</td>
<td>$2.56</td>
<td>$2.67</td>
<td>$2.62</td>
<td>$2.78</td>
<td>$2.69</td>
<td>$2.57</td>
<td>$2.68</td>
<td>$2.77</td>
<td>$2.63</td>
<td>$1.64</td>
<td>$2.64</td>
<td>$2.68</td>
<td>$2.95</td>
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<tr>
<td>CA Border</td>
<td>$2.88</td>
<td>$2.95</td>
<td>$2.95</td>
<td>$3.06</td>
<td>$3.12</td>
<td>$3.05</td>
<td>$3.02</td>
<td>$3.08</td>
<td>$3.07</td>
<td>$1.77</td>
<td>$2.64</td>
<td>$2.69</td>
<td>$3.06</td>
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<tr>
<td>Henry Hub</td>
<td>$2.87</td>
<td>$2.75</td>
<td>$2.87</td>
<td>$3.06</td>
<td>$3.12</td>
<td>$3.05</td>
<td>$3.02</td>
<td>$3.08</td>
<td>$3.07</td>
<td>$1.77</td>
<td>$2.64</td>
<td>$2.69</td>
<td>$3.06</td>
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<tr>
<td>NY Hub</td>
<td>$2.50</td>
<td>$2.44</td>
<td>$2.44</td>
<td>$2.50</td>
<td>$2.50</td>
<td>$2.50</td>
<td>$2.50</td>
<td>$2.50</td>
<td>$2.50</td>
<td>$1.77</td>
<td>$2.64</td>
<td>$2.69</td>
<td>$3.06</td>
</tr>
</tbody>
</table>

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
Regional Gas Price Differentials

Source: Bloomberg, EnerCom.
Average Natural Gas Differentials to Henry Hub

Source: Bloomberg, EnerCom Inc.