Lessons Learned Spawn New Drilling Efficiencies, Keeping Some Rigs Busy in Bakken, Niobrara

The Bakken Shale and Niobrara tight oil sands plays, as well as other unconventional plays in North America, have seen drilling activity decline sharply due to the fall in oil prices.

While the decline in the rig count is generally the first and most obvious response to collapsed oil prices, oil and gas operators in the Rocky Mountain region are nevertheless sustaining a noteworthy level of activity by continuing to push ever harder to improve drilling efficiencies by applying the knowledge gained about these two top plays.

With the information gathered from thousands of wells in recent years, operators are reducing costs and enhancing these plays’ economic viability with improved drilling efficiencies, increased recovery rates via new completion designs and well spacing, and a strengthened focus on the geography of these play areas and their existing infrastructure and on the established sweet spots for high rates of production.

We undertook this analysis mostly on the basis of a gut feeling that some analysts (and oil commodities markets) may be getting ahead of themselves by expecting a sharp drop in production in 2H 2015 that they are trying to tie to the stunning 1Q 2015 collapse in rig count.

In our weekly RADAR Report, we’ve lately been pointing out that operators are strongly focused on high-grading prospects within plays and within
Cutting costs

Improvements in rig efficiencies and increased geological knowledge contribute to well economics by decreasing drill times and improving recovery rates in the Bakken and Niobrara plays.

As the chart on p. 1 shows, the average number of days to drill a well, spud to release, in the Bakken and Niobrara improved significantly from the beginning of 2014 through the beginning of 2015.

In the Bakken, the average number of days to drill a well was 17.7 in 2014, with a high in January of 21.3 days and a low of 16 days in December. The number of days it took to drill a well in the Bakken improved by 5.3 days in all of 2014.

In the Niobrara, the average number of days from spud to release was 18.4 in January 2014, and in January 2015 the average was reduced to 12.8, representing an improvement of 5.6 days.

The charts on p. 2 detail the average days on well by top operators and by top contractors in the two combined plays. All of the top 10 operators and contractors in the two plays—ranked according to their total annual average number of active rigs in both plays combined—show improvements from 2014 to 2015 in their drilling times in the Bakken and Niobrara.

In 2014, the average number of days from spud to release was 15.4 (operators) and 16.3 (contractors), with improvements to 13.6 and 13.7, respectively. These advances in efficiencies...
reduced well costs and accelerated recovery times.

**Sweet spots**

We also took note of how well drilling has held up in these two major plays’ sweet spots.

In both cases the drilling that has held up the best and hosted the most recent wells in these two plays is focused on their core areas.

Robert Coskey, geologist and owner at Rose Exploration Inc., provided us with an updated map (p. 4, bottom) indicating the core area in the Niobrara fairway.

The US Geological Survey (USGS) map on p. 4 shows the agency’s assessment units for the greater Bakken/Three Forks-Sanish play area.

In the Bakken, North Dakota’s McKenzie, Mountrail, Williams, and Dunn counties have seen a smaller year-over-year decline, percentage-wise, in well counts than have other Bakken counties. Williams County could even boast a YOY gain in the first quarter of this year.

It’s the same story, albeit a more concentrated one, in the Niobrara, with Weld County, Colorado, hosting the lion’s share of rigs and well counts and showing a smaller decline in well counts than other Niobrara counties—save for Laramie County, which actually posted a YOY increase.

In both cases the most recent drilling activity has held up strongest in the counties occupying the areas recognized as having the best EURs and closest to infrastructure.

Bakken and Niobrara operators are focusing their drilling programs on acreage within the two plays’ core areas because these areas’ wells have the strongest production rates and most existing infrastructure.

Whiting has existing infrastructure in the Niobrara play with a gas plant and existing pipelines near its acreage in the play’s core. Hess will utilize its existing infrastructure in the Bakken with its gas plant—the only plant in the area with the ability to extract ethane.

With the possibility of a 20–40% cost reduction in the Bakken and Niobrara shale plays, top operators will be able to continue drilling in these core areas in 2015, even if the overall level of drilling activity is down. The existing infrastructure
and proven production in these core areas give operators the best chance of positive economics.

High intensity fracs, increased wells per pad, decreased well spacing and increases in rig efficiencies give operators the cost reductions and improved recovery times needed for positive returns in 2015.

**Better fracs**

Improvements in completion designs and pad configuration are also enhancing recovery factors and maximizing recovery efficiency. Because operators are utilizing high-intensity fracs, decreasing well spacing and increasing frac stages, the recovery efforts will become more efficient and produce greater returns.

Many operators continue to test various levels of proppant and frac stages when completing Bakken and Niobrara wells, moving increasingly to high-intensity fracs, with more stages and increased volumes of proppant in 2015.

Some operators are already doubling and tripling the volume of proppant and number of frac stages. QEP, in a presentation at the recent DUG conference in Denver, said it will utilize higher-intensity fracs with 10 million pounds of proppant per well typical in 2015, compared to 3.3 million pounds in 2014.

QEP is also decreasing well spacing and increasing the number of wells drilled per pad from 4 wells to 8 wells.

Oasis Petroleum will be completing all of its own wells in 2015, utilizing company-owned subsidiary Oasis Well Services.

High-intensity fracs, increased wells per pad, decreased well spacing, and increases in rig efficiencies give operators the cost reductions and improved recovery times needed for positive returns in 2015 for these two major plays. We suspect they won’t be the only US plays where operators will hunker down to keep a number of rigs running in a low price environment that very well may persist for a while. 🍾
Breaking Down the Day Rate Decline by Rig Power Type Yields Surprises

Day rates for land rigs have fallen sharply this year—not a surprise, in light of the plunging rig count and grim near-term outlook for oil prices. But there are some mild surprises in how that decline breaks down by rig power type.

According to our sister publication, the Day Rate Report, the average US land rig day rate fell by -6.3% in the first quarter of this year since yearend 2014. Stretching that metric back another 3 months increases the decline by only -0.2 percentage point to -6.5%, but the new starting point for comparison is October, when the average US land rig day rate set an all-time record of more than $19,000. That is a straight average rate, aggregated across all rig horsepower classes and all drilling markets. In putting together the Day Rate Report, we report day rates by rig horsepower class, in keeping with our long-term methodology.

In recent months, however, we have also started collecting day rates as they reflect the rig’s power type. Again, there are no big surprises: Generally speaking, AC drive rigs garner the biggest rates and mechanical rigs the smallest, with the SCR rigs fluctuating somewhere in the middle.

But upon digging a bit deeper, we discovered some apparent anomalies that may speak to the uncertainty and changing rig fleet demographics of drilling markets today.

Differentiating rig power types

In the aggregate, composite day rate data by power type suggested a much smaller drop than for the Day Rate Report results. (The power type sample may overlap a bit with rates reported for the Day Rate Report but can’t be tied specifically to the individual rates reported to the DRR). In 1Q 2015, for example, the main survey results registered a sequential decline of -8.4% vs. the rig power method’s decrease of -3.2%. The likely explanation is the weighting or absence thereof of some rig classes in the latter method’s categories.

What immediately struck us when analyzing the day rate data by rig power type was that the biggest fall in rates hit the AC rigs, both in terms of sequential decrease quarter-to-quarter and YOY decline. AC rigs’ average day rate plunged by -13.7% sequentially in 1Q 2015 after posting a YOY slide of -9.1%. A caveat is in order at this point: Because there are few active AC rigs in the

---

*Missing bars reflect the scarcity or nonexistence of AC drive rigs at the smallest and largest rig classes.
Market Dynamics

So much discussion about oil prices today is focused on when the rig count will fall far enough to spark a rally in oil prices. A superficial glance would suggest that may already be happening.

Per the nearby chart, oil prices seem to have bottomed near $50/bbl (NYMEX prompt-month) and leveled out in response to a stunningly rapid collapse in rig count, as the market’s consensus presumption that US oil production will fall in short order encouraged the oil price bulls.

“Collapse” barely does justice to the scope of the decline in active land rigs in the US in such a short span of time, whether considered from the standpoint of month-to-month changes or absolute decline from peak to trough. We think the former approach best exemplifies the speed with which this latest industry cycle has happened. From the 2Q 2014 average of $103/bbl to December, the average NYMEX futures price plummeted by 43%. But in that same timespan the active tally actually gained a net cumulative 156 rigs, and except for an odd blip in June, didn’t trend downward at all until November-December, when a tiny cumulative net loss of -0.7% aligned with an oil price plunge of 30%.

Clearly, despite the big drop in oil prices beginning in 3Q 2014, the rig count decline did not move in lockstep with foundering oil prices. But in 1Q 2015, the tally caught up with the oil price decline with a vengeance, shedding 876 net rigs. When market forces converged to keep oil prices from realizing the worst-case price scenario predicted by some analysts, the rig count hemorrhage was stanched somewhat, and the month-to-month declines have been ameliorated, with the latest MTM drop just a fourth of the 1Q average. How much of that deceleration reflects oil play economic viability vs. many independents’ difficulty in securing capital is anyone’s guess at this point.

<table>
<thead>
<tr>
<th>Rig Count by Company Classification</th>
</tr>
</thead>
<tbody>
<tr>
<td>Company Class</td>
</tr>
<tr>
<td>Majors</td>
</tr>
<tr>
<td>Large Cap</td>
</tr>
<tr>
<td>Mid Cap</td>
</tr>
<tr>
<td>Small Cap</td>
</tr>
<tr>
<td>Private Companies</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total U.S. Land Rigs by Contractor Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>Contractor Class</td>
</tr>
<tr>
<td>Large Fleet</td>
</tr>
<tr>
<td>Mid Fleet</td>
</tr>
<tr>
<td>Small Fleet</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Total U.S. Land Rigs by Operator Class</th>
</tr>
</thead>
<tbody>
<tr>
<td>10+ Rigs</td>
</tr>
<tr>
<td>4-9 Rigs</td>
</tr>
<tr>
<td>≤3 Rigs</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>
Generally speaking, we would think the risk of being overleveraged would be a bigger problem for the midsize and larger independents than for the smallest, usually privately held, independents, that rely more heavily on equity investors than on debt. So we note that operator rig stats thus far in April at first glance seems to be reversing the trend we cited in our last issue: While larger companies were reducing their rig counts in March, the smallest independents were dropping out of the count altogether. But now we find that the biggest percentage decline in the number of operators occurred in the 10+ rigs category, more than fourfold the drop in the ≤3 rigs group. And yet the midsize fleet (4–9 rigs) saw a net gain in rig count as well as a big increase (9%) in the number of operators. Here we see the impact of rig fleet downsizing by the operators that typically account for half of the rig count, those with 10 or more active rigs. And the smallest fleets’ rig counts and operator numbers appear to be stabilizing, with the latest MTM drop just a bit more than a third of the previous month’s decline.

As go the small private operators, so go the smallest drillers, with the smallest fleet actually registering a MTM gain in rig count. However, the average number of rigs per contractor slipped a bit this month for the small fleet, as this category added 12 new members—doubtless refugees from the mid fleet.

Looking at the regions, the relative strength of the Eagle Ford Shale and the Marcellus Shale compared to other major plays are helping to stem the bleeding in South Texas and Appalachia, respectively. Among regions with at least a 10% share of the total US market, these were the only ones to post just single-digit declines in rig counts. And that was a reflection of their respective top plays, with the Eagle Ford holding steady MTM and the Marcellus actually picking up 7 rigs.

As bad as the Major Unconventional plays’ collective utilization rate of 51% was in early April, it outperformed all other plays (33%) and overall US marketed rig fleet utilization (45%).

The grim numbers on utilization also reflect a continuing surge in the number of available rigs (the difference between the marketed count and the sum of active rigs plus rigs in float), a reliable indicator of day rate direction. In March, we reached the unhappy milestone of having more rigs available for work—but not yet stacked—than active rigs (1,167 vs. 985). That was still the case this month, albeit with fewer available rigs (1,054 vs. 905). That just reflects more rigs dropping out of the marketed tally with the passage of time. It also underscores the worsening outlook for day rates, as we reported in the March issue of the Day Rate Report, and the certainty of a massive flurry of rig retirements later this year.
**Surprises**, continued from p. 5

E Class (2,000 hp+), we were unable to capture an adequate YOY sample for comparison for 4Q 2014. Had there been one, the YOY comp would probably be relatively flat. However, the sequential decline in Q1 of this year was the biggest logged for any rig power type. Leading the charge downhill for AC rigs was the D Class (1,500–1,999 hp), widely regarded as the ideal rig type for drilling the horizontal wells in unconventional plays that have dominated activity in recent years. The average day rate for the D Class cohort of the AC group plummeted by $4,256, or 16.7%, from yearend 2014 through 1Q 2015. Judging from the large number of early terminations of long term contracts we’ve been hearing about in 4Q 2014, we can only conclude that many of these highly prized rigs fell to the spot market after the terminations, and desperate drillers scaled back their rates dramatically.

Mechanical rigs, with a composite rate across all 3 time periods shown in the first chart that was about $1,800 and $5,400 less than the SCR and AC rigs, respectively, showed the smallest declines, both sequentially and YOY. Falling increasingly into disfavor even in their recently improvised role as spudder rigs, it’s likely that mechanical rigs had relatively little scope to increase their rates even when the boom was still in full swing.

SCR rigs posed a bit of a surprise, however, as they were the only group to log a YOY gain (+8%) in 4Q 2014 before registering an -11.2% drop in Q1 of this year. We suspect this represents a key aspect of the ongoing evolution of the US land rig fleet: the accelerating disappearance of mechanical rigs, especially among the smallest classes.

That means that when the market recovers, SCR rigs will probably have captured more of the spudder work and conventional shallow drilling markets from the mechanical rigs while competing more aggressively with AC rigs in unconventional plays where operator returns are more marginal.

![Graph of US Land Rig Day Rates by Power Type, 1Q 2015](image-url)

*Missing bars reflect the scarcity or nonexistence of AC drive rigs at the smallest and largest rig classes.

**Actual day rates as reported in The Day Rate Report by horsepower rig class only, sans power type distinction.