

DAY RATE REPORT

2Q 2010 • VOLUME 20, NUMBER 2

Surging 2Q day rates confirm drillers' growth mode in 2010

The continuing surge in day rates confirms a drilling industry that has moved beyond recovery into a growth mode.

After lagging rising utilization rates in second half 2009, average day rates bottomed in 4Q 2009 and began to trend up in lockstep with utilization rates in 1Q 2010. The second quarter continued that trend (see figure below)

Rig rates calculated as a straight average for all rig classes in all regions across the U.S. posted a double-digit increase for the second consecutive quarter in 2Q 2010, at 12% nearly matching the 1Q 2010 gain of 11%. It's been a remarkable turnaround for a metric that was still trending slightly down as recently as 4Q 2009, finding bottom at yearend.

The comparison changes markedly when comparing day rates weighted to the average horsepower of the U.S. land fleet, which we have historically pegged at 600-750 hp (see the table at the end of this report). Using that methodology, we find that the 2Q gain was only 6% vs. 10% in 1Q 2010.

But taking a closer look at the rate breakdown by rig class helps illustrate how the 600-750 hp class is "bringing down the curve." In the table on p. 3, we list the average day rates by region for both the 600-750 hp class and the 1,500 hp class. (We exclude Appalachia from this table because it wasn't tracked in the past.) Note that the smaller rig class posted an increase of only 6% compared with a 13% jump for 1,500 hp rigs.

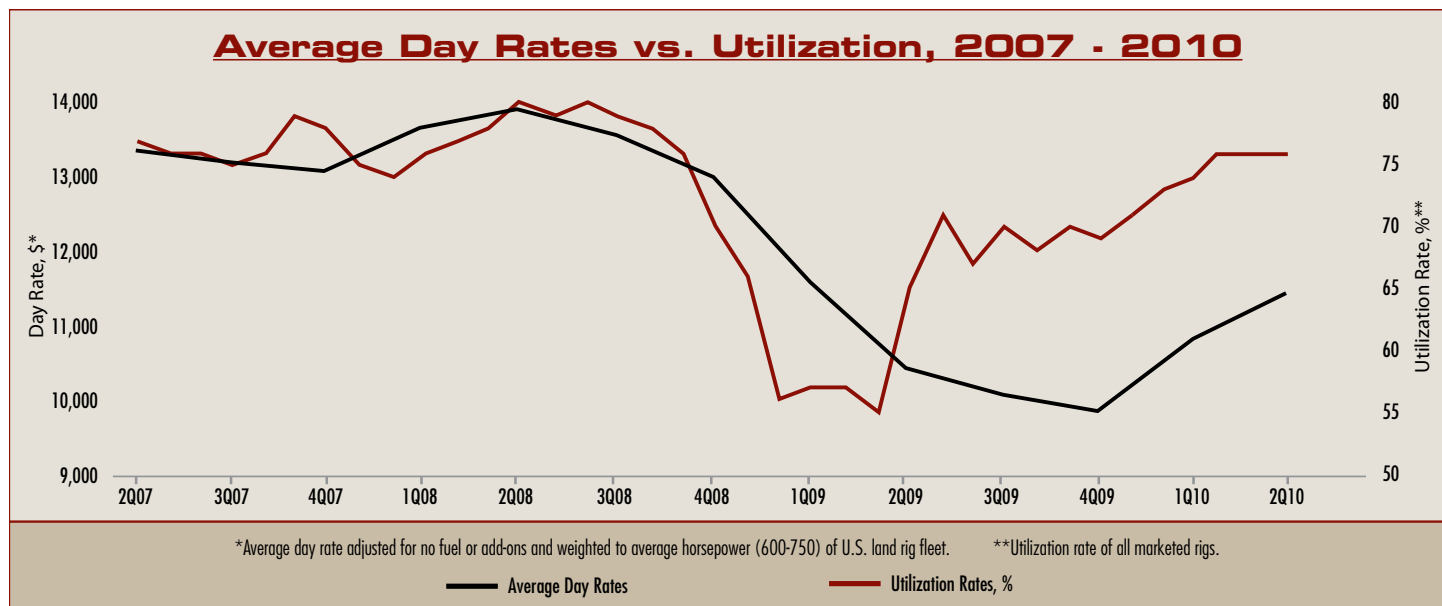
This bifurcation of the market underscores a fundamental shift in the makeup of the land rig industry being driven by the emphasis on horizontal drilling in the unconventional plays: Sub-1,000 hp rigs are becoming increasingly marginalized and oversupplied while the bigger rigs are "pulling up the curve" for day rates and are undersupplied. It's become increasingly clear to us, given the growing market dominance of 1,000–1,500 hp rigs, that the 600-750 hp class no longer represents the average horsepower of the U.S. land fleet, and we will address that shift in subsequent issues.

Propelled by strength in oil prices and expanding activity in unconventional plays, overall drilling activity has continued to increase even at the midpoint of the year. Operators have added nearly 450 rigs, or 39%, to the U.S. active count this year, pushing average utilization for the entire marketed rig fleet above 75% in 2Q—and sustaining it there for the entire quarter—for the first time since 4Q 2008.

But underpinning that feat was the performance of >1,000 hp rigs, which in many instances topped 90% utilization rates in 2Q—and frequently hit 100% early in 3Q. Accordingly, for some premium rigs in certain areas, we are seeing leading edge day rates approach levels last seen in 4Q 2008.

Day rate strength to continue

Our quarterly survey suggests that day rate strength will continue, with room for further modest appreciation but



little prospect of a downside. The degree to which that scenario is borne out depends what kind of rig you are running and where.

Rigs that are deemed “shale suitable” are commanding the spotlight today—usually 1,000-1,500 hp electric units with top drives, walking capabilities, catwalks, and the like that are often fit-for-purpose for the hottest plays: Marcellus, Eagle Ford, Haynesville, etc. A scarcity of the “right kind” of rig and crew in a hot area is a recipe for premium rates. For example, the Eagle Ford, with a utilization rate of 99%, according to the August 5 issue of our Unconventional Drilling Report, was the driver for a jaw-dropping 38% increase in day rates for 1,000–1,200 hp rigs in South Texas.

Small rigs in gas-prone regions don’t have such a rosy outlook. Units ranging 600–750 hp in gas-focused areas such as the Midcontinent showed no change vs. 1Q 2010. Even bigger rigs in gas-prone areas without a strong shale play didn’t fare any better. In the Gulf Coast market, where deep gas had been driving robust activity in years past, 1,000–1,500 hp units saw day rates remain flat.

Bifurcated rig market: oil vs. gas

The bifurcation in the rig market continued to demonstrate its staying power in the second quarter.

In terms of oil vs. gas, the trend strengthened. Even though activity remains healthy in the gas-prone shales, it’s the liquids-focused plays—both liquids-rich gas plays and pure oil shale plays—that are drawing the heat.

It’s just good business to target oil vs. gas when oil’s value relative to gas is at 16:1.

We see this trend continuing, with a greater likelihood of a downside for all gas-directed drilling the rest of this year vs. an upside and a better than even chance that oil prices will remain fairly healthy. After flirting with \$5/Mcf in 2Q, gas prices have trended steadily downhill during the early 3Q while oil prices have hovered near \$80/bbl.

Oversupply concerns are a major consideration for gas prices, and the glut doesn’t seem to be easing. Even though much of the growth in rig count is focused on liquids, many of those rigs are in fact drilling in liquids-rich unconventional gas plays and producing more gas along with the liquids. Meanwhile, the more gas-focused shale plays such as the Marcellus and Haynesville are still going strong because of their superior economics, adding still more gas supply.

The gas market is still saturated, and even a blistering heat wave hanging over much of the nation this summer has scarcely moved the needle on gas demand in a still-moribund economy.

But the longer oil prices remain above \$75/bbl, the greater the likelihood small independents will drill shallow vertical oil wells. Day rates for smaller rigs will improve as that happens, just as it did in the second half of last year.

Bifurcated rig market: rig classes

Overall average day rates will continue to gain as newbuilds and refurbishments are dominated by bigger rigs with premium features.

The article that begins on p. 12 analyzes the current crop

of newbuilds; it’s instructive to note that 7 of the 8 sub-1,000 hp rigs identified in the table accompanying that article have passed their availability date—meaning they are still in the yard, completed or not.

Oil’s strength will continue to firm up activity for the smaller drillers in oil strongholds such as California, where oil footage enjoys a 2 to 1 advantage over gas footage, and the overall footage total was up almost 29% sequentially in 2Q.

Whether that translates into higher day rates for the sub-1,000 hp rigs overall remains to be seen. Comparisons of Ready Rig counts (rigs that have drilled at least one oil or gas well in the prior four quarters) among the horsepower classes indicate that the 1,000-1,999 hp rigs have a much higher ratio of both marketed and active rigs to Ready Rig counts than the sub-1,000 hp classes. That points to a lot of stacked smaller rigs. So rates for the smaller rigs aren’t likely to improve significantly relative to the bigger units unless there’s either a lot of scrappage in the smaller classes or oil hits and stays at \$100/bbl while gas languishes at \$3/Mcf.

Costs going up too

Day rate increases aren’t just the result of greater demand. In many instances, drillers have been compelled to try to pass along increased costs. Again, the market bifurcation is evident here as well. Smaller-rig operators in still-depressed areas are still finding themselves have to offer discounts while the bigger rigs in the hot areas are able to tack on premiums.

But in general more of the smaller rigs are able to pass along these increased costs, even if their bottom line isn’t improving much.

Costs are up across the board and reflect wide differentiation among drillers.

One Rockies driller estimated costs for fuel and expendables have risen about 2–3% in the past quarter.

A Midcontinent contractor reckoned that costs for parts and components rose by 5% in 2Q, adding, “We are in a just-in-time mode. Parts people are not carrying inventory, so I have to keep it myself.”

An ArkLaTex driller blamed mainly higher labor costs for a 2–3% gain in his costs.

An Appalachia drilling contractor noted an overall increase of 3–5%: “Bits are the same, casing is the same, but labor is up. OSHA getting more thorough or frequent; citations are increasing.”

There is also the prospect of increased costs for drill pipe and OCTG, both of which have been the focus of recent, successful antidumping claims by U.S. suppliers against Chinese suppliers. Some earlier projections suggested increases of 10–15% for these commodities as a result.

Outlook

The outlook is for more cost appreciation, according to an analyst with a large independent producer. Her six-month forecast has rig costs increasing 10–15%, stimulation and cementing costs by 10–15%, and wellheads by 5–8%.

Other drillers brought up the issue of increasing regulatory costs as OSHA steps up compliance efforts. It’s apparent that the tragedy in the Gulf of Mexico has fostered a tougher

regulatory enforcement regime across the entire U.S. drilling sector, and that in itself will contribute to increased drilling costs.

Meanwhile, there are other potential scenarios that could result in a squeeze on rates.

The fallout from the gulf disaster could slow down drilling activity on land. Increased animosity towards the industry, coupled with new and highly publicized attacks on the practice of hydraulic fracturing, at the least could bog down the permitting process in the hot shale areas. We are already seeing evidence of that in Pennsylvania.

A collapse in gas prices could throttle back the surge in unconventional drilling, especially as the push to hold acreage begins to wind down.

A lack of takeaway capacity—already evident in areas such as the Bakken and Haynesville shales—could slow some drilling as the completions backlog grows to untenable proportions.

But overall expectations are for day rates to continue to mark gains in the next 6 months—perhaps modestly in comparison with first half 2010's performance, but nevertheless still part of a growth pattern.

Benchmark Average Day Rates, 2009-2010

Average day rate, 600-750 hp rig, by region, in \$

	2Q09	3Q09	4Q09	1Q10	2Q10
Midcontinent	9,600	9,300	8,825	9,600	9,600
ArkLaTex	12,500	11,450	11,000	11,750	11,875
Gulf Coast	13,000	9,600	9,500	10,200	11,000
Permian Basin	10,000	9,300	9,300	11,100	11,975
Rockies	12,000	12,500	12,000	12,500	12,700
South Texas	12,000	8,400	8,400	9,000	10,900
Group average	11,517	10,092	9,838	10,692	11,342

Average day rate, 1,500 hp rig, by region

	2Q09	3Q09	4Q09	1Q10	2Q10
Midcontinent	14,500	13,250	12,500	13,500	13,875
ArkLaTex	13,800	12,500	11,800	14,800	17,700
Gulf Coast	14,000	12,000	11,500	15,000	15,000
Permian Basin	13,000	11,500	11,100	13,000	15,500
Rockies	15,000	13,800	14,200	16,500	19,500
South Texas	14,000	11,750	11,500	15,750	18,400
Group average	14,050	12,467	12,100	14,758	16,663



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Survey: Drillers optimistic over current market

Drillers in the current day rate survey are generally optimistic over market conditions in both oil and gas basins. However, some drillers have indicated that continued subpar natural gas prices coupled with higher drilling activity in gas-prone basins could cause prospects for more work to dampen in the coming months, if the market becomes flooded with too much gas.

Meanwhile, demand indicators tracked in the Land Rig Newsletter and seen in the table below are similar or slightly improved since the 1Q 2010 survey. Most notable, however, is the improvement seen when comparing the current 2Q 2010 survey with the survey results from a year ago (2Q 2009). At that time, the industry had bottomed and drillers were pessimistic over the low number of bid inquiries coming into their offices, the high number of idle rigs in the market, and the prospects for low work volumes.

The surveys were focused on market conditions in the just-concluded second quarter, and the last responses arrived in late July.

Demand indicators show solid market

The table compares responses made during the current survey with the prior survey responses. Overall market conditions in 2Q 2010 continue to be solid and steady, with most key indicators the same or better than in last quarter's survey.

Of particular interest is the comparison on key demand indicators in the current 2Q survey with the survey from a year ago. At that time, more than 50% of drillers reported there was no waiting to get a rig and very low work backlogs. Now the industry is buzzing along at steady, but higher, work levels.

In the "Rig Wait Lists" category, 18 of 44 (41%) of drilling contractors said the amount of time required to wait on a rig had increased, compared to 25 in the prior survey who gave the same answer. An equal number said wait time was the same, compared with 13 in the last survey; four reported rig wait list time was the same as last quarter, the same number as reported in the 1Q survey. Finally, only four drillers reported there was no waiting time at all to hire a rig within their ranks during the current survey, down slightly from six who gave that same response in the prior survey.

In the "Bid Inquiry" category, 24 drilling contractors (55%) reported an increase in requests

for proposals (RFPs) during the current survey. This category is an indicator of future work prospects, and responses during the current survey basically matched responses in the prior survey. Meanwhile, 16 drillers (36%) reported the level of RFPs was the same quarter to quarter, and only four reported decreases. All drillers in the current survey reported receiving bids for future work during the second quarter, a slight improvement from the 1Q survey, wherein one driller was not bidding any work at all.

In the final category measuring "Wait on Rig Time," more than 25% of drillers (12) reported it was taking longer to get a rig now than three months ago. An equal number reported no change in the time it took to get a rig over the same period, but two said the time had decreased. Similar to last quarter, 18 drillers (40%) remarked there was no waiting to get a rig at all.

Gas price key to steady work volumes

A majority of drillers surveyed expect work volumes over the next six months to be steady to better with oil prices holding up and many customers needing to spend their budgets before yearend.

However, many drillers continue to express concern, as they have in several recent surveys, over natural gas prices. Some believe gas prices may drop again later in the fall or winter if too much gas is in storage or a mild winter causes a slip in demand.

Six drillers said they expect work volumes to hold up through the summer but slide over the winter months for varying reasons. Two drillers in the Rocky Mountains expect

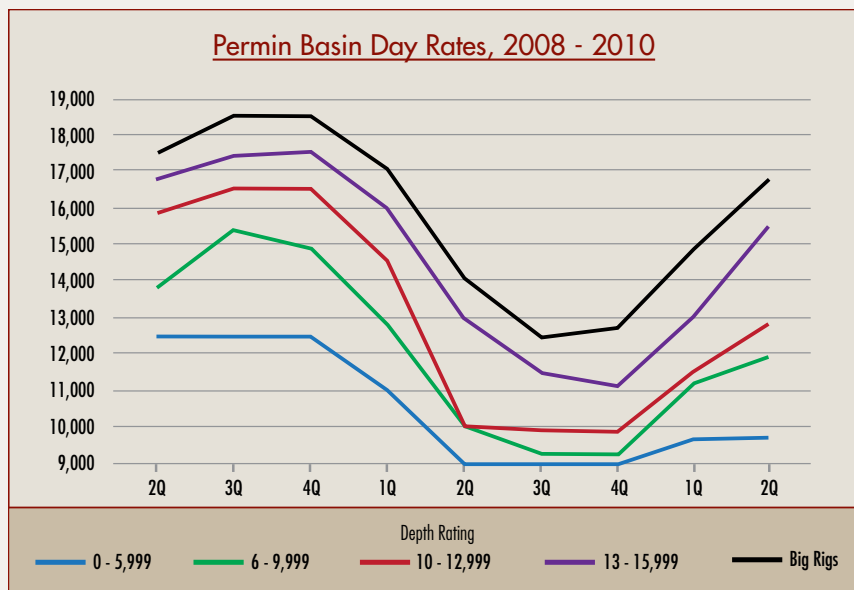
Demand Indicators Show Solid Market

Current Survey End 2Q10	None	Decreasing	Same	Increasing	No Response
Rig Wait Lists	4	4	18	18	0
Bid Inquiries	0	4	16	24	0
Wait on Rig Time	18	2	12	12	0
Prev. Survey Early 1Q10	None	Decreasing	Same	Increasing	No Response
Rig Wait Lists	6	4	13	25	0
Bid Inquiries	1	5	17	25	0
Wait on Rig Time	18	1	8	21	0
1 Year Ago End 2Q09	None	Decreasing	Same	Increasing	No Response
Rig Wait Lists	27	10	8	8	1
Bid Inquiries	4	11	15	23	1
Wait on Rig Time	31	8	7	7	1

Market Snapshot: Permian Basin

Bigger rigs are faring quite nicely in the Permian Basin thanks to operators applying some “unconventional” know-how to some strong “conventional” oil plays. Case in point is the combo Wolfberry play involving the low-permeability Spraberry and Wolfcamp formations being developed with long laterals and multiple frac packages. A more conventional but busy play is previously overlooked shallow Grayburg-San Andres potential in the Fuhrman-Mascho field area. The former underpins a double-digit rate gain in rates (12%) for 1,000 hp rigs drilling mainly vertical wells, while the latter attracts more 600-750 hp rigs, which rose 8% in 2Q.

Even the lure of higher oil prices has done little, however, to move the needle on day rates for the smaller rigs because of continuing overcapacity in those classes. Sub-500 hp rigs currently have a Ready Rig utilization rate of only 40% in the Permian Basin vs. the region’s overall Ready Rig utilization around 70%. That suggests a big overhang of stacked rigs keeping downward pressure on small rig day rates. And 2Q’s survey bore that out, as <500 hp rigs managed to eke out a mere 1% gain.



“We are trying to get more wells drilled before new regulations come in.”

“We are getting more calls for rigs, but we are maxed out.”

“Customers are optimistic over the oil price.”

a seasonal slip in rig demand over the winter due to weather; two others expressed pessimism over impending legislation that could put additional tax burdens on the industry.

Another driller, in Appalachia, expects continued strong drilling in the Marcellus area for horizontal work but foresees a slowdown in shallow well drilling over the winter.

Customers mixed on market outlook

Drillers reported that many customers had a mixed outlook on the drilling markets. Some reported producers are expressing optimism over the stabilization of oil prices at higher levels and are able to move forward with more drilling plans, but others remarked that customers continue to voice concern over gas prices.

Some contractors mentioned other issues that are concerning customers, including higher tax burdens and more stringent safety and environment regulations.

Meanwhile, a few drillers remarked that some customers are having trouble “selling deals” while others are not.

Some drillers hiking wages to retain workers

For the second survey in a row, some drillers reported that wages are going up, but many reported no change in wages.

In 1Q 2010, a few drillers reported they had to entice rig hands back into their workforces with higher wages, but during the current survey more than 25% of drillers (12) reported having to pay higher wages to keep workers from moving on to competitors with the rig count rising.

Among the 12 reporting increases, wages have risen approximately 5% to 10%.

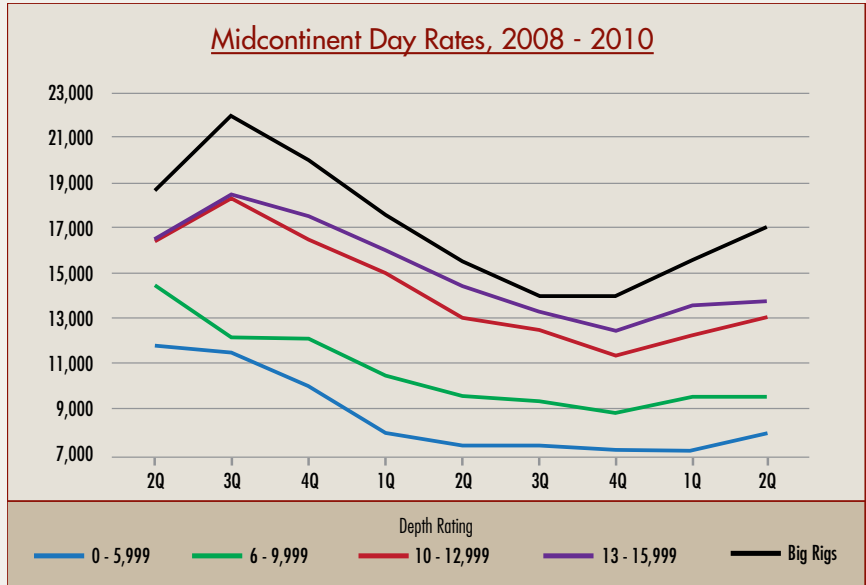
Wage increases are evident in toolpusher ranks, as well as for drillers and floorhands. Toolpusher salaries have climbed as high as \$130,000 a year; driller wages are as high as \$30 an hour; and floorhand wages are as high as \$21 an hour in some drillers’ ranks.

Costs of goods, services up

In the current survey, costs of goods and services across

Market Snapshot: Midcontinent

Strength in oil prices has bolstered the modest recovery in Midcontinent day rates. After declining or stagnating for a year, all rig classes have now seen an uptick in rates this year. The slide in rates had continued until 1Q 2010, when all rig classes save <500 hp posted noteworthy gains. The small rig category sustained yet another drop in average day rates, 2%, in 1Q vs. 4Q 2009. It was the only group of any region that declined in 1Q. Now the <500 hp rigs have caught up, making up for lost ground by posting the biggest gain of any class in the region at 11%. Other increases across the Midcontinent fleet were modest, ranging from 3% (1,500 hp) to 10% (2,000 hp). An exception was the workhorse 600-750 hp group, flat sequentially on rates in 2Q following a first quarter in which rates climbed 9%. Drillers are telling us that higher operating costs are behind the rate gains for the smaller rigs, not surging demand. Utilization rates of late have hovered under 70%, not the kind of demand that stimulates rate hikes by itself. It's a different story for the 1,000 and 1,500 hp units, where utilization rates have been running in the upper 80s and upper 90s, respectively, owing to surging demand in the Woodford Shale and Granite Wash tight sands plays. But these classes enjoyed rate gains of 9% and 8%, respectively, in the prior quarter, suggesting that their modest respective increases of 4% and 3% in 2Q represented a slight cooling off. We see more upward movement in day rates for these two categories as activity expands grow in the newly burgeoning Anadarko Woodford as well as the hot Granite Wash and steady Arkoma Woodford plays with continued firm oil prices.



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“We see wait lists growing in oil plays.”

“Customers are somewhat optimistic on oil, but not on gas.”

“We see costs of some supplies gaining due solely to regulations.”

“Operating costs are higher by 5%; supply companies are driving up costs.”

“Operators have deals to drill and want to get them done over the next six months.”

“Rig wait lists are shrinking; activity level is the same, but there's more competition.”

the board have inched up 1 to 2% in the 2Q 2010 survey, similar to findings in the 1Q 2010 survey. Gains in pricing for fuel, expendables, and drill bits were noted by some drillers.

Consolidation among parts and component suppliers was causing some prices to rise as competitors are eliminated, according to a few rig owners. Others reported the same suppliers were not discounting parts and components as much and that some had even increased prices.

A Midcontinent driller remarked that his component supplier was not carrying as much inventory as before so he was forced to buy and hold more items in his own yard.

Two drillers reported that OSHA regulators were issuing more citations on equipment and that action had caused them to replace more items than normal during the second quarter.

Market Snapshot: Rocky Mountains

If you have a >1,000 hp rig in the Rocky Mountains, you're in clover. The three bigger classes of rigs logged double-digit increases in rates in 2Q. But the smaller rigs looked anemic, as the 600-750 hp class notched a mere 2% gain in average day rate vs. 1Q. The frenzy that is the Bakken Shale certainly explains the former case. Bakken rig counts more than doubled in 2Q (an average of 73) from 3Q 2009 levels, and at the end of July hit 111. Look for 1,000 and 1,500 hp rig rates to continue to climb. Competition for rigs in the Bakken is already spurring fit-for-purpose newbuilds targeting that play. As the newly emerging Niobrara oil shale play in Colorado's Denver-Julesberg Basin catches hold, expect competition for those rig classes to heat even more.

Another bright spot has been the resurgence in tight sands gas drilling. Looking at the four major tight sands gas areas—DJ, Uinta, Piceance, and Green River—their combined rig tally was up 36% at the end of 2Q vs. the average for 3Q 2009. Some of the know-how spawned in the shale boom seems to be seeping into the tight sands plays, as those operators begin to rely more on horizontal drilling and multiple frac stages.

But regulatory concerns combined with low gas prices are leaving other drilling theaters in the Rockies depressed. One small private driller working smaller rigs in New Mexico's San Juan Basin, in noting a bleak outlook for the next 6 months, opined, "Everything is dead here because of government restrictions."

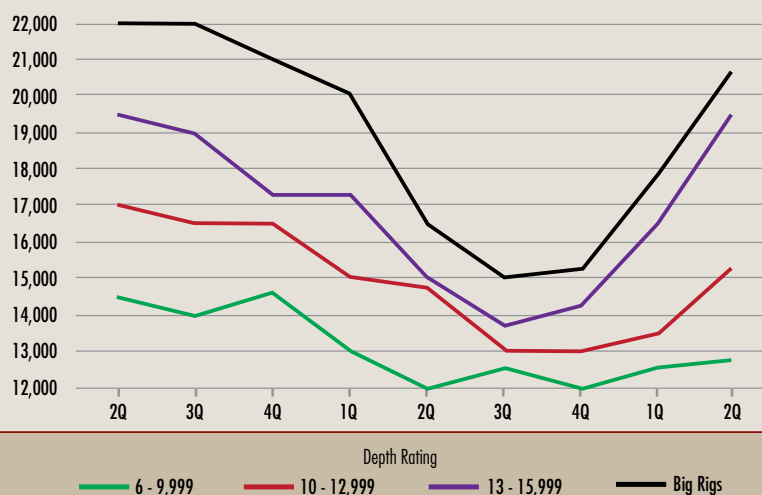
Leading edge rates up; more increases possible

Overall leading edge day rates across all regions have moved up about 3% since the prior survey, which is similar to the rate increase recorded in the 1Q 2010 survey.

While some areas have recorded significant increases as new contracts are signed, many contractors continue working on term contracts or for the same customers at the same rates quarter to quarter, which helped moderate overall increase averages.

A total of 23 of the 44 surveyed rig owners reported increases in leading edge rates, while 20 said rates were the same. A small Rocky Mountains driller reported a 20%

Rocky Mountain Day Rates, 2008 - 2010



"Rigs are tapped out in the Williston and Hugoton basins."

"We are continuing to see rigs in good demand."

"We will see some consistency in work volumes, but then it will fall off in winter and pick up again in April."

"The number of bids is up. People are shopping prices because a lot of contracts are up. They're using quotes to play off other competitors."

"Operating costs are the same. Nobody is passing any discounts our way. We have to do all the cutting on our end."

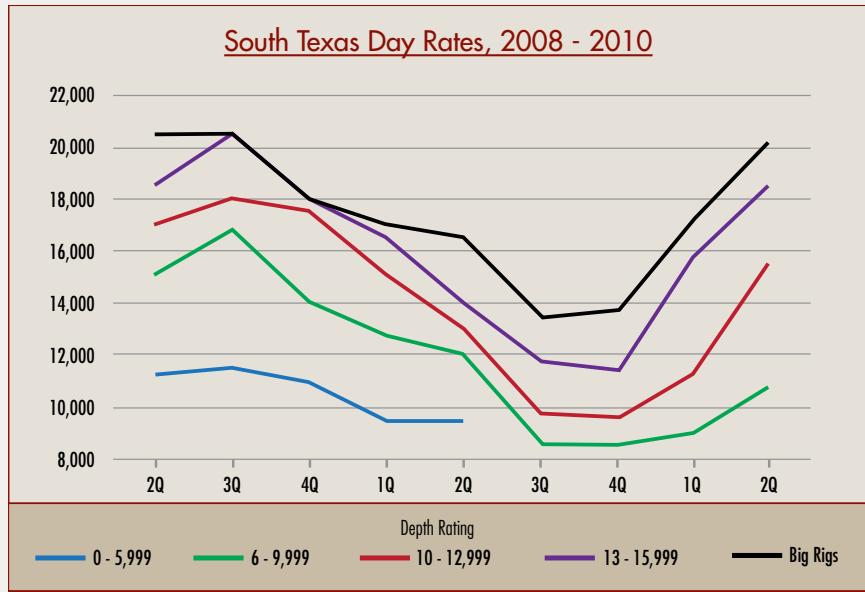
decline in leading edge rates due to too many rigs being available in his area.

Looking forward, more than one-half (23) of the 44 rig owners expect overall rig rates to be steady over the next six months, with no big ramp-ups expected. However, 21 expect rates to rise about 3% to 4% over the same period. No one expects a decline in rates.

An Ark-La-Tex driller reported that often drillers will try to go up a little on rates when a rig's contract comes up for renewal during a period of heavy demand, but will lose the work if the rate increase is too hefty. He explained that it is better to push rates up a little at a time rather than too much at once.

Market Snapshot: South Texas

There are a lot of happy drillers in South Texas, judging by our survey responses for rigs 600–750 hp and up (we weren't able to collect rates for <500 units). The region blew away the rest of the field with an average increase of 23% for all horsepower classes in 2Q. All categories reported double-digit gains vs. 1Q. Especially pleased were drillers with premium 1,000 hp units, enjoying a 38% spike in rates, and in some instances snagging the same \$20,000 rate as some of the 1,500 hp rigs. That's more than double the average rate for this class of rig in 3Q 2009. What's amazing is that the bigger rigs had comparable double-digit increases in 1Q as well.



The catalyst for all this good fortune has been the Eagle Ford—the poster child for the industry's shift in unconventional to those plays with strong liquids components. The Eagle Ford wasn't registering on our rig counts a year ago but as of late July had doubled its tally since the end of 2Q. It looks to be on track to reach 100 rigs by 4Q 2010.

Expectations for one midsize driller are positive for the next 6 months: "New electric rigs with top drives are at 98% utilization everywhere" in the play, he noted.

That kind of activity level suggests a wave of fit-for-purpose newbuilds in the offing, which will itself nudge up rates for these premium rigs even further. One major public driller guessed that rates will escalate at least another 5-10% over the next 6 months.

"We've got customers looking for new rigs to drill in the Eagle Ford."

"We are very positive on the amount of work we are looking forward to over the next six months."

"Customers are satisfied with the Eagle Ford and are confident drilling in it."

"Wait on rig time is up; we're booked until next June. All new rigs are drilling in the Eagle Ford."

"Wait lists are growing. We're very busy here."

Market Snapshot: Appalachia

The frenzy that is Marcellus action today has completely transformed the Appalachian drilling market. What for decades had been a haven for sub-1,000 hp rigs has seen a substantial influx not only of bigger rigs but of the premium, fit-for-purpose bigger rigs that are deemed ideal for drilling horizontal wells in the cramped, mountainous terrain of Pennsylvania and West Virginia. Consequently, the day rate picture has become a fractured one.

The table shows a historical series of rates weighted to reflect the 600–750 hp rigs that dominated the region for many years. Although we started posting rates for bigger rigs in 1Q 2010, we still don't have enough of a history to display them all graphically. But we can see the impact of the premium rigs in the elevated rates for all rig classes. While the benchmark average rig rate rose only 5% in 2Q vs. 1Q of this year, that just reflects the change for the 600–750 hp units that are now steadily losing market share in the region. Taking a straight average for all reported rig classes for the two quarters would yield an increase of 9%. Weighting the rates according to active rig horsepower capacity utilization in the Appalachia would produce an even larger sequential gain. The marketed utilization rates in Appalachia—as reported in the end-July issue of The Land Rig Newsletter's Biweekly Report—for rigs ranged from 23% to 66% <1,000 hp vs. 82% to 92% for the >1,000 hp units.

The average rate for 1,500 hp rigs in Appalachia that we obtained in our survey of drillers was, at \$20,750, the highest for this category encountered in this report. In a separate survey of operators, the rate for a 1,500 hp SCR electric rig with top drive ranged from \$19,500 to \$23,000. The latter tied a Rockies report for the top rate for this kind of rig.

But a rising tide lifts all boats. It might seem counterintuitive that the ≤500 hp rigs should post a slightly bigger sequential gain at 12% than the 11% logged for the 1,000–1,200 hp group, especially considering that the former recently has shown marketed utilization rates of less than 25%. That just confirms two things: the small rigs had nowhere to go but up, and there is still a fair amount of shallow vertical drilling going on in Appalachia, including about 14% of the Marcellus rigs, according to the latest issue of The Unconventional Drilling Report.

There are several factors contributing to the brightening outlook for Appalachia. One driller there said he expects rig work volumes to “keep growing a bit.”

He added, “Folks are busier due to [impending] lease expirations, and the price of gas is holding up better than expected. Everybody is seeing more money than expected.”

1Q07	2Q07	3Q07	4Q07	1Q08	2Q08	3Q08	4Q08
\$11,475	\$11,300	\$11,790	\$11,375	\$11,670	\$11,730	\$11,775	\$11,230

1Q09	2Q09	3Q09	4Q09	1Q10	2Q10
\$11,120	\$10,025	\$10,200	\$10,800	\$11,700	\$12,275

“It’s a mixed bag—different customers saying different things. They’re concerned about new laws and regs. Others are saying oil price is good, but still others are saying there are still a lot of rigs out there. No consensus”

“Everything is up about 2-3%. Fuel and expendables are higher.”

“I’m not seeing any of my parts suppliers cutting in deals recently.”

“There could be a rig shortage in a year because of Marcellus programs.”

Market Snapshot: ArkLaTex

Guarded optimism about gas prices and confidence about oil prices have ArkLaTex drillers hopeful that healthy drilling activity levels will continue. All three of the >1,000 hp classes enjoyed strong double-digit percentage gains in day rates quarter to quarter. Only a puny 1% increase for the 600-750 hp group kept the consolidated average day rate for all classes from posting a whopping 23% jump in rig rates in 2Q. Even at that, the across-the-board rise of 17% was the second-best among all the regions we surveyed.

Rigs rated to 1,000, 1,500, and 2,000+ hp all enjoyed percentage gains in the low 20s sequentially in the ArkLaTex during 2Q 2010.

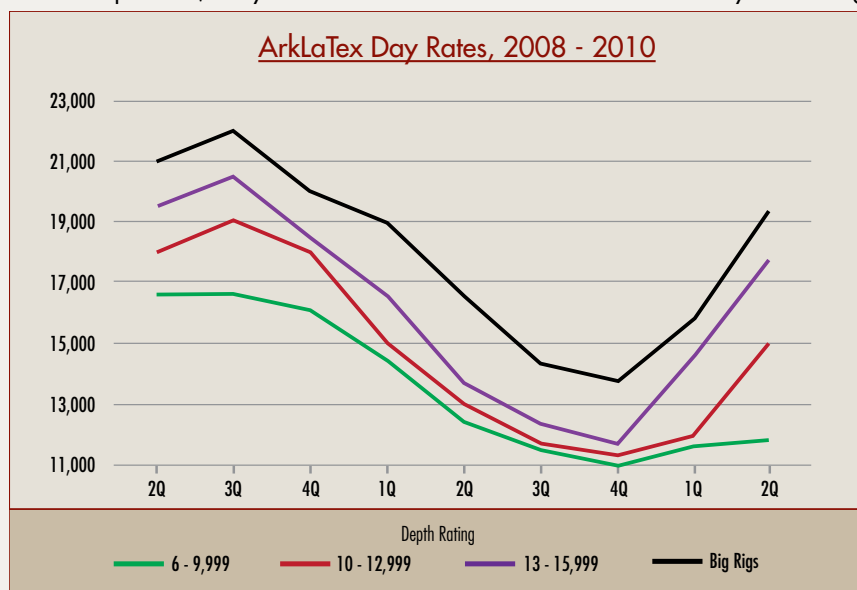
Leading the charge was the indomitable Haynesville, which has kept more than 100 rigs busy all year long in the core Louisiana portion of the play, according to The Land Rig Newsletter's Biweekly Report. (This doesn't include some 75 rigs active in recent months in the non-core Louisiana and east Texas portions of the Haynesville, as tracked by our companion newsletter, The Unconventional Drilling Report.)

An executive with one big independent operator told us his company was paying \$21,000–23,000 for a 1,500 hp SCR electric rig with a top drive in the Haynesville. A midsized independent reported day rates of \$22,000–24,000 for the same type of rig in the Haynesville and \$19,000–20,000 for a 1,000 hp SCR electric rig with a top drive there.

Haynesville operators have kept drillers busy largely because of the play's superior economics: While the wells are fairly costly, the huge IPs promise quick payouts. But another factor has been the scramble to hold acreage in this relatively young play following a boom in leasing over the past several years. The Haynesville looks to be slowing down, as rig counts measured either by the benchmark core Louisiana or the entire two-state play have scarcely budged for several months. The greater Haynesville, while still accounting for 10-12% of the total U.S. rig count at present, may have reached the same level of maturity in drilling action as its regional companion shale

play, the Fayetteville. The latter's rig tally has failed to break out of a band at 33-39 for about a year now, paralleling the drop in gas prices to below \$5/Mcf. As the industry continues to shift towards liquids in conventional and unconventional plays, expect the growth in rates to flatten out in the gas-prone areas such as the Haynesville and Fayetteville.

One midsized driller active in the Haynesville/Middle Bossier plays in East Texas said work is "steady now and hopefully will move higher in the next 6 months," as gas prices eventually rebound in response to an improving economy and a tightening supply/demand balance.



“We are cautiously optimistic that gas prices will settle above \$5.”

“Continued growth in certain shale plays is good for bigger rigs.”

“Second-half activity will increase due to the oil price.”

“Gas is hit or miss; [customers] are not bullish on gas; they’re still worried about gas prices, so there is minimal drilling.”

Market Snapshot: Gulf Coast

The long-suffering drillers of the Texas and Louisiana Gulf Coast had another quarter to muddle through, but there are glimmers of upside amid the gloom. As would be expected for the weakest major region in terms of activity, the Gulf Coast also logged the smallest gains in day rates among the areas we survey.

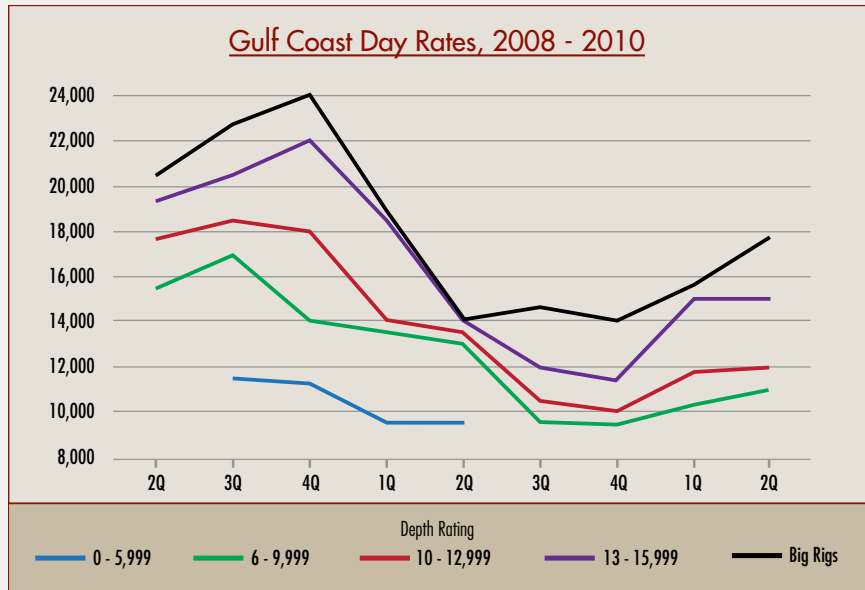
Counting all rig classes, Gulf Coast day rates rose on average by a paltry 5% in 2Q vs. 1Q. The sole bright spots were the 600–750 hp and big rigs, notching respective gains of 8% and 13%.

The 1,500 hp group was dead in the water at \$15,000 for two consecutive quarters, but it must be noted that this followed a period from 4Q 2009 to 1Q 2010 in which day rates for these units jumped 30%. Rigs in the 1,000–1,200 hp

range barely registered a blip by inching up another 1% in rates in 2Q. But that followed a spike of 19% in 1Q. Drillers tell us the prior increases were largely a spillover effect from the resource plays in other regions and not an indication of underlying strength comparable to the demand for those classes of rigs along the Gulf Coast.

A contributing factor in the prior increases was a hike in operating costs. And now those higher operating costs are forcing increases in day rates for the less-popular rigs at both ends of the size spectrum as well. One small private driller in Louisiana reported an operating cost increase of 10%.

What pulled up the rate for big rigs by a hefty 13% was a handsome \$19,000 rate one major public driller reported on the Texas coast. That's the highest rate for a 2,000 hp rig on the Gulf Coast our survey has captured since 1Q 2009.



“Operating costs are up 10%; services in general are going up.”

“Rig wait lists are increasing because people need to replace production. They must drill for it or buy it.”

“Work volumes over the next 6 months will stay pretty active, but folks are concerned about federal policy.”

“Customer outlooks are a mixed bag. We’ve got some that say they can sell their deals and others that say they can’t.”

“Customers are migrating to liquids.”

“We see inquiries increasing because customers have got to replace their production.”

Rig fleet changes tracking unconventional's surge.

By the end of this year—and probably much sooner—more than half the rigs in the U.S. will be drilling in unconventional oil and gas plays. The vast majority of these will be drilling horizontal wells. And almost all of that subset will comprise 1,000 hp and 1,500 hp units.

Because the demand for these classes of rigs has pushed utilization to the max, there is a surge of newbuilds under way for such rigs.

At the same time, there is a lingering surplus capacity of rigs overall in the U.S., and no strong signs yet of a wave of scrappage to whittle down that glut.

Welcome to the paradox that is U.S. drilling today: surplus coupled with shortage; newbuild wave weighed against overdue scrappage.

The market will only become increasingly bifurcated, and that means continued strength in day rates for rigs in the 1,000–2,000 hp range and continued relative weakness for <1,000 hp rigs. While there were some regional exceptions to this rule in 2Q 2010, it was clear that increases in day rates among the smaller rigs were the result of them finally catching up to their larger brethren's gains that were manifested in 1Q 2010. In some instances, the smaller rigs in 1Q were still working at cash operating costs just to keep staff employed and some revenue coming in. However, the shale boom has put upward pressure on the cost of everything from wages to consumables, and the ripple effect has compelled the drillers not so blessed with "shale-suitable" rigs try to push through these costs to customers.

Right now, there is little interest in <1,000 hp newbuilds, and even less for the smallest horsepower rigs. All but a handful of newbuilds we've identified are 1,000 hp or bigger (see table).

Robust oil prices have been the saving grace for these smaller rigs. Were that not the case, a number of small, private drillers would have closed their doors by now, as the conventional gas drilling market remains moribund. Many of these smaller rigs have been stacked for a long time.

Some drillers with fleets dominated by smaller rigs have indicated that they're not in a rush to scrap—parting out

just when they need to, and otherwise hanging on with oil conventional oil drilling opportunities.

Utilization rates, scrappage questions

Marketed utilization rates for either of the two smallest horsepower classes have topped the 70% mark briefly just twice since October 2008 (see figure, p. 13). Utilization rates for the 1,000 hp and 1,500 hp units have not fallen below 70% in the past year.

An even more telling metric for ascertaining future candidates for scrappage is the Ready Rig utilization rate. (A Ready Rig is any rig that has drilled an oil or gas well in the preceding four quarters.) Using the early August active rig count, we calculated Ready Rig utilization rates of 42% for <500 hp units, 59% for 500-999 hp rigs, 78% for 1,000-1,499 hp units, and 96% for 1,500-1999 hp rigs.

An educated guess is that about a third of the readily available fleet is stacked. The two smaller horsepower classes account for almost 70% of those readily available, stacked rigs that have not worked in more than a year. And most of those are refurbished rigs that are at least 30 years old.

Even with that situation, however, the evidence to date—both anecdotal and data submissions—does not indicate a big surge in scrappage. What we are hearing instead is that rigs rated to less than 750 hp are getting freshened up cosmetically, while substantial upgrades are planned for anything bigger. Those upgrades typically entail switching power from mechanical to electric, adding a top drive, expanding mud pump capacity, or adding drawworks horsepower.

Stacked rigs still evident in fleets

We tried to get a feel for the status of today's rig fleet by asking our survey participants about their number of stacked rigs and plans for refurbishments, newbuilds, and scrappage.

Nearly one-half of rig owners (21 of 44) reported a total of 57 warm-stacked rigs were on standby for new work. This number is down considerably from the 117 found in the 1Q 2010 survey.

More than one-fourth of contractors (12 of 44) reported a total of 34 cold-stacked rigs within their fleet ranks as well. Meanwhile, only one driller in our survey will scrap a total of two rigs this year. However, this same driller, in the Rockies, is replacing these rigs with two new single-derrick rigs.

Newbuilds, refurbis

The upshot is that the demand for shale-suitable rigs has become so strong

2010 Newbuilds by HP, Power Type*

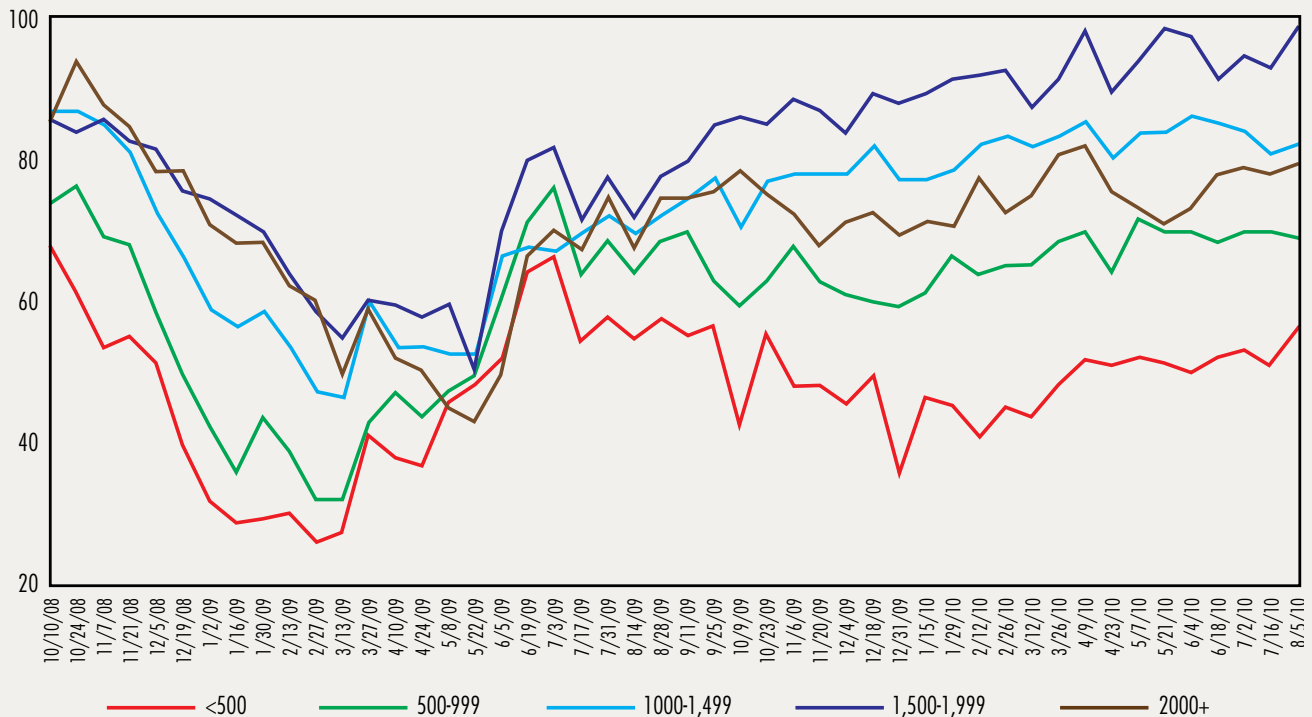
Horsepower class

Power type	<600	700-900	1,000-1,400	1,500	2,000	NA**	Totals
Electric			1				1
SCR			7	7	1		15
VFD			15	13			28
Mechanical	4					2	6
NA**	2	2	3	1			8
Totals	6	2	26	21	1	2	58

*As of June 2010 data from RigData's Rig Equipment Database.

**Information not available

US Rig Utilization by Horsepower Class



that it has sparked a flurry of newbuilding and refurbishments despite there being too many rigs overall in the market.

The three biggest drillers have embarked on aggressive newbuild programs to chase unconventional plays with premium rigs:

- Helmerich & Payne recently signed contracts to build and operate another nine FlexRigs., bringing its fiscal 2010 newbuilds tally to 19, with delivery through midyear 2011.
- Patterson is adding 23 APEX newbuilds to its fleet this year and plans another 11 next year.
- Nabors has awards for five new PACE rigs and three substantially upgraded SCR rigs, bringing its current commitments to 12 under construction. It expects at least 5 more new rig commitments in the near future.

The three biggest contractors were not included in our survey. Nearly one-third (14) of drilling contractors we surveyed remarked they were refurbishing or upgrading rigs. Some

drillers reported heavy overhauling of rigs, including converting some older, mechanical rigs to electric power. Others are installing bigger mud pumps and/or top drives. One Rocky Mountain driller is adding new catwalks, and several contractors are upgrading drawworks to 1,000 to 1,500 horsepower. In addition to refurbishing older rigs, 11 surveyed drillers are building or are looking to build a total of 16 new rigs—all of them in the 1,000 to 1,500 horsepower range.

Despite the strong interest in these “sweet spot” rigs, some drillers are skittish about building on spec, just as some operators aren’t in a rush to commit.

“We’re looking at one 1,500 hp with a top drive, but we’re not going to do it unless we get a guaranteed contract,” said one midsize Rockies area driller.

And a small Gulf Coast driller reported customers “kicking the tires” on a prospective 1,500 hp newbuild.

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Regional driller market shares shift with tilt to liquids

The dominant 2Q 2010 theme in shifting market shares among drillers was the tilt towards drilling for oil and liquids-rich gas.

Regions that gained the most market share in 2Q vs. 1Q 2010 typified the continuing drift of drilling activity away from natural gas and toward liquids. The rig counts have certainly reflected that shift. Overall, the combined total oil and gas rig tally tracked by The Land Rig Newsletter's Biweekly Report had reached a recent peak of 2,085 in early October 2008, following a recent gas rig peak of 1,548 the month before. The oil rig count at that time was running less than 25% of the total rig count. Oil's share of the rig count topped 38% at the end of 2Q 2010 and 43% early in 3Q 2010. Most of the loss in overall rig count from 3Q 2008 to 2Q 2009 came in gas-directed drilling, falling by about 1,000 units from peak in 3Q 2008 to trough in 2Q 2009.

That situation led a loss of market share by gas-prone regions to oil-dominated regions. The trend continued in 2Q 2010, for example, with the ArkLaTex (-6%) ceding market share to the Permian Basin (+3%).

Meanwhile, the unconventional oil and gas plays continued to demonstrate their growing dominance of drilling markets, which is reflected in the substantial growth in footage quarter to quarter. As most of the shale wells now involve horizontal drilling, and horizontal wells typically amass more footage than vertical or directional wells, it follows that an increase in horizontal drilling would mean an increase in overall

footage as well. Indeed, total footage in 2Q jumped by nearly triple the gain registered sequentially in 1Q 2010 vs. 4Q 2009—up 11% vs. 4%, respectively. That tracks growth in horizontal drilling's market share, which rose to 55% of the total footage at end-2Q from 52% at end-1Q.

It might seem counterintuitive for gas-prone regions to lose market share as unconventional drilling continues to post activity gains, considering that unconventional gas has been the big story in drilling circles for several years. But the unconventional drilling picture is increasingly oily as well. The hottest areas today are the Bakken and Eagle Ford shales—the former being a nearly pure oil play and the latter being a hybrid oil/gas/liquids-rich-gas play. And the new plays that are heating up or just now opening up are liquids-focused: the Niobrara oil shale in the Rockies, the liquids-rich Collingwood/Utica gas shale in the Michigan Basin, and the liquids-saturated Granite Wash tight sands gas play spanning the Texas Panhandle and western Oklahoma.

Small drillers will still fare well in oil strongholds such as California and the Permian Basin as long as oil prices stay robust. But the overwhelming dominance of the unconventional plays and the concomitant growing need for "shale-suitable"—bigger, more modern—rigs will shunt more of the small drillers to the side.

Market shares by contractor and by region are ranked according to footage in the tables.

Here is a roundup of regional market share breakdowns:

Alaska

The utter collapse of land-based gas drilling in Alaska's Cook Inlet region marked the most notable change in that state. Inlet Drilling Alaska, a small private driller focused on the Kenai Peninsula, saw its market share in Alaska plummet 81% sequentially in 2Q. It remains to be seen whether there will be any ripple effects on onshore drilling in the region from an expected spurt of Cook Inlet offshore drilling spawned by new state tax incentives.

Meanwhile, the top three drillers in Alaska continued to vie for business on Alaska's North Slope even as overall drilling declined with the usual seasonal downturn. Nabors has almost doubled its market share in Alaska since 3Q 2009, mainly at the expense of Doyon Drilling, which has seen its chunk of the market halved since then. Despite the 2Q North Slope decline of 22%, Alaska earlier this year saw its share of U.S. footage nearly triple from 3Q 2009 levels.

2Q		ALASKA		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
Nabors	288,928	48.1%	Nabors	276,848	41.8%
Doyon Drilling	181,462	30.2%	Doyon Drilling	209,467	31.6%
Nordic-Calista	120,000	20.0%	Nordic-Calista	116,542	17.6%
Inlet Drilling	10,000	1.7%	Inlet Drilling	60,000	9.1%

Appalachia

The Appalachian drilling market has been completely transformed in the past year. In 2Q 2009, the top drillers were Falcon, Union, Nomac, and Dallas Morris, in that order. Only Nomac—a subsidiary of Chesapeake, the leading Appalachia driller—remains from that group. Nomac still leads in market share, but gaining ground are big public drillers Helmerich &

2Q		APPALACHIA		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
Nomac	1,007,877	21.6%	Nomac	985,264	23.0%
Patterson UTI	655,355	14.0%	Patterson UTI	614,650	14.4%
Precision	371,517	7.9%	Falcon Drilling	359,680	8.4%
Helm. & Payne	337,455	7.2%	Precision	334,638	7.8%

Payne and Patterson UTI bringing in premium rigs to target the hot Marcellus action. H&P, making good on its promise to stake a major claim in the Marcellus action, now has 10 FlexRigs working in the play. It's not all 1,000+ hp electric rigs dominating Appalachia activity, though, Precision managed to jump two slots in market share position, and it runs a handful of 600-750 hp mechanical rigs in addition to its bigger rigs, both electrical and mechanical. While Appalachia's overall market share held steady in 2Q, it was down 19% from a year ago. That underscores the impact of low gas prices on conventional drilling in the region in spite of the booming (and apparently immune) Marcellus.

ArkLaTex

A comparable tale could be told in the ArkLaTex region, another gas-prone region where a sizzling gas shale play had soared, undaunted by slumping gas prices. Despite the robust activity in the Haynesville Shale and steady work in the Fayetteville Shale—ArkLaTex lost 1.6 percentage points in market share even as its overall footage numbers climbed. The region nevertheless still accounted for the biggest chunk of the drilling market in 2Q, just as it represented the biggest market share in active rig count at about 21-22% during the quarter. But overall, it's been a steady slide in market share from 31% in 3Q 2009 and 27.2% in 4Q 2009. We might see this trend continue, as the Haynesville seems to have peaked shy of the once-predicted 200 rigs and remains constricted in a band around 180-185 in recent months. Although the two big shales will underpin a healthy level of drilling by high-spec big rigs the rest of the year, smaller rigs will continue to lay down in the ArkLaTex absent a spike in gas prices. Sub-500 hp rigs have all but disappeared from the active rolls in the region, contributing to the likelihood that ArkLaTex will soon relinquish its spot as the No. 1 active rig fleet. Market shares have churned substantially. For the two prior quarters, the top four drillers remained the same, although there was a bit of shuffling within their ranks. But the 2Q saw Helmerich & Payne, Nabors, and Trinidad drop out of the top four rankings altogether. One explanation might be the departure of those firms' premium rigs in search of higher rates in the Eagle Ford. Even though Nomac survived that transition, it still lost market share, as the spoils were spread across a bigger pool. None of the top four ArkLaTex drillers in 2Q topped a double-digit market share.

2Q		ARKLATEx		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	22,329,308	26.1%		21,372,323	27.7%
Nomac	2,210,925	9.9%	Nabors	2,995,650	14.0%
Precision	1,780,829	8.0%	Helm. & Payne	2,351,776	11.0%
Rowan	1,660,032	7.4%	Nomac	2,290,968	10.7%
Scan	1,135,290	5.1%	Trinidad	2,069,270	9.7%

just as it represented the biggest market share in active rig count at about 21-22% during the quarter. But overall, it's been a steady slide in market share from 31% in 3Q 2009 and 27.2% in 4Q 2009. We might see this trend continue, as the Haynesville seems to have peaked shy of the once-predicted 200 rigs and remains constricted in a band around 180-185 in recent months. Although the two big shales will underpin a healthy level of drilling by high-spec big rigs the rest of the year, smaller rigs will continue to lay down in the ArkLaTex absent a spike in gas prices. Sub-500 hp rigs have all but disappeared from the active rolls in the region, contributing to the likelihood that ArkLaTex will soon relinquish its spot as the No. 1 active rig fleet. Market shares have churned substantially. For the two prior quarters, the top four drillers remained the same, although there was a bit of shuffling within their ranks. But the 2Q saw Helmerich & Payne, Nabors, and Trinidad drop out of the top four rankings altogether. One explanation might be the departure of those firms' premium rigs in search of higher rates in the Eagle Ford. Even though Nomac survived that transition, it still lost market share, as the spoils were spread across a bigger pool. None of the top four ArkLaTex drillers in 2Q topped a double-digit market share.

California

Sturdy oil prices are keeping California's drilling scene on an even keel, as the oil-prone action there helped keep the state's footage near a 1% market share for the second quarter in a row while increasing a whopping 29% in volume. Helmerich & Payne pushed past Ensign to take the No. 1 spot among California drillers, adding more than 6 percentage points to its market share in the process. H&P had

2Q		CALIFORNIA		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	880,157	1.0%		684,698	0.9%
Helm. & Payne	360,000	40.9%	Ensign USA	244,698	35.7%
Ensign USA	281,007	31.9%	Helm. & Payne	236,000	34.5%
Nabors	112,000	12.7%	Nabors	109,000	15.9%
Paul Graham	67,150	7.6%	Kenai Drilling	60,000	8.8%

come out of nowhere in California, not registering a single foot of drilling there in late 2009, to vault into second place in the first quarter of this year. H&P and Nabors are active in the Elk Hills area. Ensign and Paul Graham keep busy drilling mainly for California independents—shallow heavy oil wells in the San Joaquin Valley and moderate-depth gas wells in the Sacramento Valley. Look for the rig count to rise in California, based on a large number of recent oil development filings.

Gulf Coast

The Gulf Coast region halted its market share slide this year following the second half 2009 rebound from a dismal 2Q 2009. That's small comfort for the worst performer among the regions in terms of permitting growth, rig utilization rates, and day rate gains. And the problem has persisted for many months now: The Gulf Coast Ready Rig utilization rate (a metric of rigs that have drilled at least one oil

2Q		GULF COAST		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	4,908,176	5.7%		4,294,520	5.6%
Precision	877,080	17.9%	Nabors	850,863	19.8%
Nabors	824,670	16.8%	Helm. & Payne	687,580	16.0%
Patterson UTI	685,670	14.0%	Precision/GW	597,763	13.9%
Helm. & Payne	618,102	12.6%	Patterson UTI	474,050	11.0%

or gas well in the prior four quarters) at last report was a pathetic 29%, a full 25 percentage points less than the next-worst performer in this telling metric.

The gas-dominated Gulf Coast not only lacks oil, it lacks any of the buzzy unconventional gas plays that help make up for being gas prone in today's market. Still, the region posted a 14% gain in footage as the same four drillers shuffled rankings.

Midcontinent

Look for a sizable uptick in footage to continue in the Midcontinent as activity accelerates in liquids-rich shale and tight gas plays. We're seeing significantly increased levels of permitting and drilling in the Granite Wash tight sands play that sprawls across the Texas Panhandle into western Oklahoma. Interest is growing in the Anadarko Woodford Shale as well because of its hefty liquids content. And robust oil prices also have sparked new infill drilling in the shallow oil fields of Kansas and Oklahoma. Permitting activity continues apace in both the Arkoma and Anadarko basins. All of the top four drillers in the region notched footage gains as they shifted rankings around, as did the region itself, up 12% from 1Q.

2Q		MIDCONTINENT		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	12,412,274	14.5%		11,098,901	14.4%
Cactus Drilling	2,680,684	21.6%	Cactus Drilling	2,231,958	20.1%
Unit	1,702,770	13.7%	Helm. & Payne	1,572,281	14.2%
Helm. & Payne	1,676,673	13.5%	Unit	1,385,200	12.5%
Nomac	1,042,045	8.4%	Nomac	737,372	6.6%

Midwest

The smallest of the drilling markets has seen activity dwindle to less than a third of the activity it saw in 3Q 2009. Only about 30-35 rigs have been active in the region lately, almost all run by small, privately held drillers. But a dramatic new discovery well has restored hope to this beleaguered region. An EnCana subsidiary has opened a new gas shale play with a high liquids content in the Michigan Basin. Record leasing activity has followed, and it's likely that more contractors will come in to chase the evolving Collingwood/Utica Shale play because of the region's lack of bigger rigs to handle the extensive horizontal drilling needed. The EnCana subsidiary, Petoskey Exploration, plans to drill additional wells to delineate the play this year. Bigard & Huggard Drilling and Warren Drilling continue to top the ranks of Midwest drillers, active mainly in Michigan and Ohio, respectively.

2Q		MIDWEST		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	162,322	0.2%		258,922	0.3%
Bigard & Huggard	36,691	22.6%	Bigard & Huggard	44,905	17.3%
Warren Drilling	34,790	21.4%	Warren Drilling	42,425	16.4%
Pollister Drilling	34,006	20.9%	Advanced Energy	32,066	12.4%
G & H Drilling	16,200	10.0%	Les Wilson Drilling	31,812	12.3%

Permian Basin

If the Permian Basin activity continues to grow at its current pace, it could challenge the leadership of the ArkLaTex by next year. While logging a 14% increase in footage in 2Q, the region further expanded its market share by 3%. That followed two consecutive market share gains of 19% in 4Q 2009 and 5% in 1Q 2010. As always, the wealth was spread among the largest pool of active drillers among the regions:

2Q		PERMIAN BASIN		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	17,319,218	20.3%		15,188,435	19.7%
Patterson UTI	2,346,582	13.5%	Patterson UTI	1,886,588	12.4%
Big Dog Drilling	1,340,300	7.7%	Lariat	1,352,000	8.9%
Lariat	1,287,050	7.4%	Big Dog Drilling	1,151,150	7.6%
Helm. & Payne	1,125,125	6.5%	Helm. & Payne	1,000,210	6.6%

63. There is some evidence of consolidation within the basin, however. In 3Q 2009, no driller had a double-digit market share; Helmerich & Payne led the pack with a mere 7.09% market share, with Patterson hot on its heels at 6.77%. That started to change in 1Q 2010 when Patterson jumped to the top spot with a 12.4% share. Patterson further consolidated its gains in 2Q with a 24% rise in footage. Look for that trend to continue, as Patterson at last report was running twice as many rigs in the Permian as its nearest competitor. Patterson and Big Dog have been especially well-established in the Spraberry Trend, where action targeting the combo Wolfberry (Spraberry + Wolfcamp) play continues to intensify. Add to that a flurry of drilling in Fuhrman-Mascho acreage, and strong oil prices should keep Permian activity robust for the foreseeable future.

Rocky Mountains

The Rocky Mountain region continues to soar with hot Bakken action, accelerated tight gas drilling, and an emerging new shale—the Niobrara. But the key word here is liquids. A year ago, gas accounted for 63% of drilling in the region, with a rig count of 144 (end-July 2009). According to our most recent data, the gas share there now is 46%, and the rig count has leapt to 255 while marketed fleet utilization rose from 72% to 81%. (Interestingly, before natural gas prices plummeted in 3Q 2009, the Rockies had a much higher footage market share—more than 24% as of 2Q 2009.) The Rockies also logged the second biggest footage volume gain among the regions in 2Q, for a sequential increase of 13%. Each of the top four drillers held the same spots as in 1Q but also marked sizable volume gains as well. With permitting continuing at healthy levels, notably in the Bakken and the major tight sands basins, the Rockies should sustain a strong level of activity throughout the year.

2Q		ROCKY MOUNTAINS		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	13,168,146	15.4%		11,651,113	15.1%
Nabors	2,678,224	20.3%	Nabors	2,308,940	19.8%
Helm. & Payne	1,718,433	13.0%	Helm. & Payne	1,572,038	13.5%
Ensign USA	1,605,957	12.2%	Ensign USA	1,520,374	13.0%
Patterson UTI	1,424,546	10.8%	Patterson UTI	1,125,421	9.7%

Southeast

Except for a tidy gain in footage volume, nothing else changed appreciably in the Southeast, which continued to recover some of its market share after a steep plunge in 1Q. Rapad, long the dominant driller in the region, relinquished some of its market share to a number of its competitors, but none approached even half its piece of the pie. The regional driller has focused on oil targets in Alabama and oil and gas in Mississippi for a handful of independents.

2Q		SOUTHEAST		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	1,212,622	1.4%		916,583	1.2%
Rapad Drilling & Well	493,027	40.7%	Rapad Drilling & Well	434,100	47.4%
Nabors	240,750	19.9%	Nabors	184,630	20.1%
Energy Drilling	106,600	8.8%	Energy Drilling	69,144	7.5%
Precision	72,000	5.9%	Precision	60,000	6.5%

South Texas

South Texas continued to build on its market share in 2Q—up 6% from 1Q—thanks to the ongoing surge in the Eagle Ford hybrid play. And that frenetic pace will only continue in a play that, as much as the Bakken, shaped industry's thinking on prioritizing liquids in unconventional plays. The latest tally of active rigs in the Eagle Ford, in early August, was exactly double the 2Q average. Coincidentally, like the Rockies, the top four South Texas drillers also held the same slots as they added significant footage volumes vs. 1Q.

2Q		SOUTH TEXAS		1Q	
	FOOTAGE	SHARES		FOOTAGE	SHARES
	7,731,475	9.1%		6,656,012	8.6%
Nabors	1,880,270	24.3%	Nabors	1,435,320	21.6%
Helm. & Payne	1,356,125	17.5%	Helm. & Payne	1,100,866	16.5%
Patterson UTI	990,886	12.8%	Patterson UTI	827,303	12.4%
Precision	867,894	11.2%	Precision/GW	785,003	11.8%

Grand Total 85,399,287

Grand Total 77,060,301

Nabors, however, built on its market share, expanding it by 12.5% and jumping its active rig count there to 27 by the end of 2Q from 17 at the end of 1Q. Our early August Biweekly Report also shows Nabors with the top market share in the Eagle Ford at 26% and 17 rigs.

2008-2010 quarterly day rates*

	Depth	2Q08	3Q	4Q	1Q09	2Q	3Q	4Q	1Q10	2Q
Midcontinent	0-5999	11,700	11,500	10,000	8,000	7,500	7,500	7,350	7,200	8,000
	6-9999	14,500	12,780	12,600	10,500	9,600	9,300	8,825	9,600	9,600
	10-12999	16,250	18,250	16,500	15,000	13,000	12,500	11,250	12,500	13,000
	13-15999	16,500	18,500	17,500	16,000	14,500	13,250	12,500	13,500	13,875
	Big Rigs	18,650	22,000	20,000	17,500	15,500	14,000	14,000	15,500	17,000
ArkLaTex	0-5999									
	6-9999	16,500	16,500	16,000	14,500	12,500	11,450	11,000	11,750	11,875
	10-12999	18,000	19,000	18,000	15,000	13,000	11,850	11,450	12,000	15,000
	13-15999	19,500	20,500	18,500	16,500	13,800	12,500	11,800	14,800	17,700
	Big Rigs	21,000	22,000	20,000	19,000	16,500	14,500	13,900	15,750	19,333
Gulf Coast	0-5999		11,500	11,200	9,600	9,600				
	6-9999	15,500	17,000	14,000	13,500	13,000	9,600	9,500	10,200	11,000
	10-12999	17,750	18,500	18,000	14,000	13,500	10,500	10,000	11,900	12,000
	13-15999	19,500	20,500	22,000	18,500	14,000	12,000	11,500	15,000	15,000
	Big Rigs	20,500	22,850	24,000	19,000	14,000	14,500	14,000	15,750	17,750
Permian Basin	0-5999	12,500	12,500	12,500	11,000	9,000	9,000	9,000	9,600	9,650
	6-9999	13,800	15,450	14,800	12,800	10,000	9,300	9,300	11,100	11,975
	10-12999	15,800	16,500	16,500	14,500	10,000	9,900	9,850	11,500	12,875
	13-15999	16,750	17,450	17,500	16,000	13,000	11,500	11,100	13,000	15,500
	Big Rigs	17,500	18,500	18,500	17,000	14,000	12,500	12,700	14,900	16,700
Rocky Mts	0-5999									
	6-9999	14,500	14,000	14,600	13,000	12,000	12,500	12,000	12,500	12,700
	10-12999	17,000	16,500	16,500	15,000	14,750	13,000	13,000	13,500	15,200
	13-15999	19,500	19,000	17,200	17,200	15,000	13,800	14,200	16,500	19,500
	Big Rigs	22,000	22,000	21,000	20,000	16,500	15,000	15,250	17,750	20,675
South Texas	0-5999	11,200	11,500	11,000	9,600	9,600				
	6-9999	15,000	16,750	14,000	12,750	12,000	8,400	8,400	9,000	10,900
	10-12999	17,000	18,000	17,500	15,000	13,000	9,750	9,500	11,200	15,500
	13-15999	18,500	20,500	18,000	16,500	14,000	11,750	11,500	15,750	18,400
	Big Rigs	20,500	20,500	18,000	17,000	16,500	13,500	13,800	17,250	20,250
Appalachia	0-5999	Note on Appalachian rates								9,400
	6-9999	The only historic series of Appalachian rates compiled by the Day Rate Report is a weighted average reflecting the smaller rigs that predominated there until recently. Going forward, we will publish separate rates for each rig class we survey in Appalachia.								11,700
	10-12999									16,900

*Rates quoted in dollars per day without fuel or other add-ons. All numbers are averages of reported responses from telephone surveys.

Average Day Rates*

1Q04	2Q04	3Q04	4Q04	1Q05	2Q05	3Q05	4Q05	1Q06	2Q06	3Q06	4Q06	1Q07
7,700	7,900	8,200	8,800	9,600	10,800	12,000	13,425	14,100	14,700	14,850	14,400	13,800
2Q07	3Q07	4Q07	1Q08	2Q08	3Q08	4Q08	1Q09	2Q09	3Q09	4Q09	1Q10	2Q10
13,450	13,200	13,100	13,650	13,900	13,580	13,000	11,525	10,480	10,090	9,850	10,850	11,500

*Average day rate weighted to average horsepower (600-750) of U.S. land fleet.