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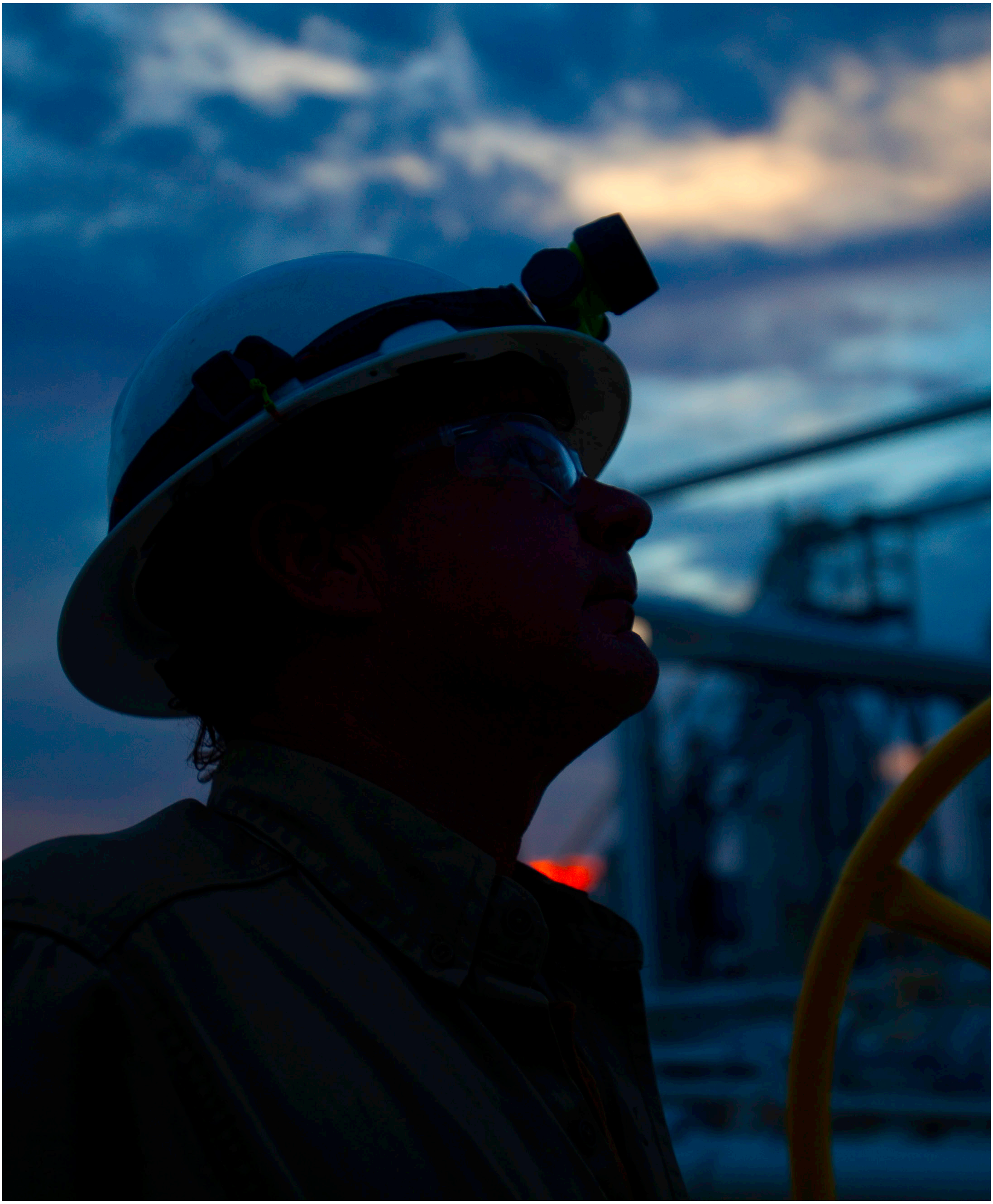

Enhanced recoveries via new science have Eagle Ford operators looking up.

THE EAGLE FORD'S SCIENCE LAB

Eagle Ford Shale operators are leveraging the economic slowdown by bulking up on technical knowledge to enhance recoveries.

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If actions speak louder than words, the roar from the flight of capital and rigs out of the Eagle Ford Shale over the past 18 months is deafening. The eight-year-old vaunted South Texas play, once a star on the stage of U.S. shales, has experienced rig retreat like none other during the depths of this recent historic price collapse. Across its 200-mile-wide band along the Gulf Coast, a mere 29 rigs remain in action as of late May, according to Baker Hughes' rig count, down from 305 at its peak. That's an 88% fallout, and in spite of an upward trend in the price of oil, the thud of rigs dropping persists.

EOG Resources Inc. and Marathon Oil Co. remain the most active drillers, accounting for some 36% of basin activity, a Tudor, Pickering, Holt & Co. research note observed, "with Karnes County being the only county with more than a handful of rigs running."

Production in the Eagle Ford rolled over in early 2015. Following the rig exodus, the Energy Information Administration reported March 2016 Eagle Ford oil production was near 1.3 million barrels per day (MMbbl/d), down 21% from its March 2015 peak of 1.7 MMbbl/d.

Tudor, Pickering analysts said they were "surprised by the staggering declines seen in the Eagle Ford over the last nine months," estimating an oil price of $63/bbl is needed to hold basin production flat. Researchers at Platts Analytics estimated producers need $40/bbl "just to break even." At its investor day meeting in May, Plains All American Pipeline LP projected a 600,000-barrel drop in Eagle Ford production from peak to trough, bottoming in May 2017, and leading all other basins in decline.

But don't be fooled: Eagle Ford stakeholders know they're holding onto a sleeping giant.

"Make no mistake. The Eagle Ford still has a lot of running room," said Billy Helms, EOG executive vice president of E&P, at a Barclays conference in May. The company is the largest acreage-holder in the play at more than half a million. "It's still very much a growth engine for the company … [with] a lot of advancements on stimulations, completions and well spacing. We are excited about where the play will go."

Active operators like EOG are taking advantage of the slowed drilling pace—and soft service costs—to push the envelope on drilling and completion (D&C) technologies to juice recoveries and maximize cost efficiencies.

One such company is Encana Corp. "We continue to test a multitude of different technologies," said Eric Greager, Encana vice president and general manager of western operations. "Across the board, in any given area, we have improved our EURs consistently as we've driven costs out and reduced cycle times. The big opportunity now is to test at a relatively low-cost basis."

Sanchez Energy Co. COO Chris Heinson attested that much of the traditional Eagle Ford core continues to be fully economic at today's prices. The company leads the charge in squeezing costs out of the D&C process and is now focused on enhancing recoveries.

"The Permian, Scoop and Stack plays do have fantastic economics, but even outside the core of the Eagle Ford, we can still duplicate $30/bbl economics. It takes a bit of work, but it can be done," he said.

The answer lies in the science.

Previous page, the Sanchez Production Partners central processing facility "D" captures Eagle Ford production from Sanchez Energy Co.'s 106,000-acre Catarina assets in Dimmit and Webb counties, Texas.

Rock matters

Bill Von Gonten Jr. pointed to a well log spread across a table illustrating the strata for 100 feet of the Lower Eagle Ford Shale, where most operators are landing laterals today. He is the founder and president of W.D. Von Gonten & Co., a Houston-based petroleum engineering and core lab company. The consistent mineralogy along the section is what's notable—and deceiving, he said.

"If you look at this openhole log tract, it's the same from top to bottom; the mineralogy doesn't change that much. So, theoretically, anywhere we land the lateral should connect to the rock from top to bottom. This is what all the models say, and everybody's doing it."

But wells drilled in close proximity—from the same pad even—can vary up to 75% in productivity and EUR. Yet reservoir pressure, temperature, thickness and porosity are similar. What's the larger variability?

"The variability is the connectivity to the rock with hydraulic fractures," Von Gonten said. "If you look at the real rock of the Eagle Ford, you see layering with variations of hard and soft layers. The openhole logs don't show that.

"In the Eagle Ford, we drill wells that are 250 to 300 feet apart, and most aren't communicating. So what happened to our frack that was designed for 300 feet? Yes, we are creating these fractures, but we're not creating connected conductivity that the hydrocarbons can flow through. We're finding that it doesn't look like our models said it should. We've been modeling it all wrong."

In fact, the downhole logging tools most commonly used today take measurements every six inches, then averages in between, creating that lazy, consistent curve seen on Von Gonten's printout. In reality, the strata are a layer cake of fine laminations of calcite, mudstones and volcanic ash—fractions that vary down to an inch thick. It's these repeating tiny hard and soft layers that control the height growth of a hydraulic fracture—and limit its connected vertical growth.

To better understand the nature of the rock, Von Gonten analyzes well cores in centimeter and millimeter resolution. From this, he can identify thin layers of varying compositions and weak interfaces in the rock, and thus better model how the frack will propagate. "Now look at the same mineralogy on centimeter resolution," he said, pointing to a jagged well log parallel to the previous one. "They should be the same, but you have big variations."

Not surprisingly, he has discovered that connected fracture heights are not reaching as far from the wellbore as most operators believe.

"We're not connecting vertically 150 feet" away from the lateral. "I think it's more like 50 to 70 feet." And the loss between the outer extent of the frack and the total reservoir is linear in ultimate recovery of the well. "That is lost reserves you're not accounting for."

At \$100/bbl oil, the industry didn't care so much about the nuances of the rock, he said, because "at \$100 oil, frankly, everything worked." Now, "companies are going back to science and trying to understand it. If you can spend the same amount on a frack and get a 30% increase in production for dollars spent, that's a win-win for everyone."

And during this slowdown in drilling activity, operators are eager to account for those reserves on the bottom line.

"We're not creating connected conductivity that the hydrocarbons can flow through," says Bill Von Gonten, founder and president of W.D. Von Gonten & Co. "We've been modeling it all wrong." Below, a Sanchez Energy wellsite targeting Eagle Ford in Webb County, Texas.

Profitable acreage

Sanchez Energy targets its 6,000-foot-plus lateral wellbore into a 10-foot vertical window of the Eagle Ford, based upon core and log analysis along the entire 300-foot column of the formation. Among typical geoscience data such as porosity, permeability and mineralogy, it is specifically looking for barriers between target zones. The company drills a vertical pilot well every two to three miles apart to gather this data prior to initiating large-scale development.

"This is key to our success," Sanchez's Heinson said. "We've invested a lot of money in understanding the science behind picking our drilling targets, and it's produced better results—period. Largely without dramatic changes to our completion design, we've been able to uplift production by roughly 50% with more definitive, precise targeting of our zones."

Sanchez's wells in its focus area, in the south-central Catarina region in southern Dimmit and northern Webb counties, clock in at 1.1 million barrels of oil equivalent (MMboe) EURs. With well costs at $3.3 million and less, that's greater than an 80% internal rate of return (at $55/bbl oil, $3.50/Mcf gas and NGLs at 25% of WTI). Even at $40/bbl oil and $2.50 gas, "that's strong economics," he said.

One positive side effect of targeting the wellbore is the opportunity for more well locations. "Where the Eagle Ford was once largely seen as a one-horizon play, we now see multiple benches to be developed. In Catarina, we've been able to expand it up to three zones."

And fully developing all zones in a section is better than infill drilling later, he said. "It's a lot harder to put in that extra well later than when the initial development takes place. We find that you get better performance if you complete all wells simultaneously, minimizing sand and fluid hitting in older wells."

Sanchez uses the data from the pilots to determine how many wells it will place in a section. It usually lands laterals in at least two horizons and sometimes three. A typical Sanchez pad will contain five to 10 wells.

"You want to get all those horizons developed at the same time. You'll never have a cheaper opportunity to drill those wells than when you've got the rig on the same pad, and you're completing them all together."

The Houston-based producer is also continuing to refine and optimize its completions technology through the downturn. Heinson said completion designs industrywide are trending less exotic and more simple, but much bigger. Far field proppant placement is the goal today, he said.

"The focus now is to get the pumped sand out in distance. When you're creating these hydraulic fractures, you want the sand grain to transport as far away from the wellbore as possible."

And while he keeps the company's fluid system close to the vest, he did say finer proppant mixed with more fluid creates longer frack wings—or distance from the wellbore—"and longer frack wings give you better results overall." The company measures microseismic events some 250 feet from the wellbore, but getting sand placed that far from the lateral "is a whole other challenge that we've been focused on optimizing. We're incrementally improving results quarter-over-quarter."

Across the Eagle Ford, Sanchez holds some 200,000 net acres, but during the downturn, the company has retreated to its Catarina region.

"By concentrating in one area, it's allowed us to stay efficient with our money through economies of scale and focusing on getting service costs as low as possible." Well costs are now $3.3 million, compared to $7.4 million 18 months ago. Heinson considers 50% of the gain from process efficiencies, the other half from service company concessions. "When there is a rebound, we're going to be much more profitable at any oil price than we were previously."

Much of the cost efficiencies are within the completions phase, in which the company contracts for pressure pumping, but de-bundles the materials. For instance, it sources sand directly from the sand mine, to be delivered directly to the wellsite, thus eliminating an interim step where it is held at the service company's transloading site. It similarly plans such logistics for chemicals and other services that go into a well.

"There was an inefficiency associated with the process of using a service company, and we've been able to dial a lot of that back."

Sanchez has earmarked $200 million to $250 million for the Eagle Ford in 2016, and it plans to run just one rig during the second half of the year, following 2015 when it ran two to three rigs, and down from eight at its peak in 2014.

"We're going to proceed with caution," Heinson said. "We can make a lot of acreage extremely profitable; we just have to focus on it."

Understanding the science behind picking drilling targets has been the key to Sanchez Energy's success, said COO Chris Heinson. "It's produced better results, period."

Sticking the landing

With rock as saturated with hydrocarbons as the Eagle Ford Shale, you would think the landing position of the lateral wouldn't matter. But according to Von Gonten, it matters because rock matters. "I hate the idea of these resource plays as being statistical. The rock is going to control what happens to these fracks."

For the first approximately 20 feet of radius around the wellbore, the nature of the rock doesn't matter so much. The intense energy of the frack will break through most sublayers, regardless. But as the fluid starts to spread away from the wellbore and lose energy, the weak contacts between hard and soft layers begin to influence the path of the frack.

"Every time the frack hits an interface between a soft and hard layer, it has to make a decision as to the path of least resistance," Von Gonten explained. "If the interface between the layers is weak, it may

Facing page, Sanchez Energy has focused its one rig for the remainder of the year on its South Texas Catarina holdings in the Eagle Ford condensate window.

Sanchez Energy geosteers its lateral into a 10-foot narrow window for best results.

hesitate and go out rather than up before finally building up enough pressure to break through. Finally, as the velocity at the frack tip decreases, it doesn't have enough energy to grow any further. The further it grows out, the lower the remaining energy to overcome these interfaces and the further they slow down the frack."

Think of it like climbing stairs, he said: At the outset you're energized, but eventually you tire until you can't climb anymore. "Same thing happens with a frack; the energy dissipates."

Weak interfaces within the rock also create paths for fluid leak-off. The result is a micro version of a fault line, created by a large number of tiny interfaces, spreading the frack wide rather than tall. Identifying these soft and hard rock layers and their interfaces is what best determines where to land the wellbore lateral.

"If you put the lateral near these weak interfaces"—within that 20 feet—"you may overcome them with energy. We've seen that we can move the lateral placement by just 15 feet and make a 30% change in ultimate recovery. In just that little bit of distance, it's huge."

While reservoir quality matters, a 10% change in porosity will change ultimate recovery by just 1% or so. "But if I can change the connected prop frack height by 10%, I change the ultimate recovery by 10%. It's linear. Stimulated rock volume is the big knob we need to focus on.

"For years we've focused on porosity—the storage capacity of rocks—and what we really need to focus on is, How do we connect these rocks?"

Von Gonten said his company is writing computer code that will redefine frack models, but it's the centimeter resolution that reveals the rock code. "We're not reinventing the wheel here; we're just getting to the resolution where we can see what's really going on."

But companies can start making a better decision when landing laterals even without the new models, he said.

"Just study the layering present in core and ask, Where are the weaker interfaces?" Once one understands the effect of interfaces on fracture propagation, "intuition tells you to land the lateral near those weak layers and overcome them with energy to increase the surface area of the frack. You need to start with core, as the openhole logs do not have the necessary resolution."

Companies are beginning to realize they aren't connecting with as much rock per well as they once thought and are downspacing to reach the remainder. Yet Von Gonten characterized tighter spacing as "a brute force" method.

"We don't understand it, so let's just drill wells closer together. Once we understand the rock and how our fracks are propagating, then design a landing point and frack design to maximize ultimate recovery. You can then spend the same amount of capital and increase the ultimate recovery, without spending more capital to fill in the gaps."

Lonestar rising

Fort Worth-based E&P Lonestar Resources Inc. is also using the global slowdown to high grade its optimization strategies. "We've had an incredibly straightforward strategy since day one—returns, returns, returns and nothing else," said Frank Bracken, CEO. "We have been more liberal in our willingness to apply new techniques and technologies to improve results."

In addition to geosteering its laterals to optimize lateral placement, Lonestar also employs other techniques that Bracken characterizes as "doing things right." These include maximizing reservoir quality, pumping substantially more proppant on tighter stage spacing, managing chokes—"we haven't been on anything bigger than a 20/64th in six months"—and drilling longer laterals.

Underwhelming results from wells drilled in 2014 motivated Bracken to rethink how the company drilled and completed its wells. In 2015, Lonestar began utilizing openhole logs run to total depth prior to casing to better analyze rock properties. This has since affected both the company's landing zone and frack design. The log data "caused us to narrow our target window considerably" from a 50-foot window to a 20-foot window, he said. "We figured our best recovery correlated to this specific window."

Lonestar is using these lateral logs to engineer its completions rather than simply set the stages geometrically along the lateral. "It allows us to evaluate the lithology and how conducive every foot of rock is to fracture stimulation."

Specifically, employing Schlumberger's Broadband Diverter product, the company is able to isolate rocks with different stress qualities within each stage and then design the stimulation according to a high or low pressure pump rate.

"We think we're breaking more rock along the lateral," he said.

"If you just set your stages geometrically, you're setting stages across rock with highly varied initiation pressures—you're going to pump your entire job into the path of least resistance. Some of your perfs won't see meaningful propping, and that's ineffective. We want to move our stage spacing and perforations to be able to initiate like rock, with a low initiation series of perfs and a high pressure set of perfs, so that we get high perforation efficiency."

For example, when half of a stage breaks down at 300 pounds of pressure, and the other half at 800 pounds or higher, "your scientific intuition tells you that you're breaking new rock and getting better perf efficiency. It could result not only in the wells recovering more oil, but doing it in a more cost-efficient fashion."

Thus far the company has completed five wells this way. Since altering the landing zone and stimulation practices, Bracken said, per-

STRETCHING THE BASE

The dramatic decrease in Eagle Ford drilling activity is not solely related to commodity prices, but to rig efficiency as well, noted Marathon Oil Corp. spokesperson Lee Warren. "Significant improvements in drilling efficiency have also been a factor in the decreased rig count, as companies are able to drill more wells per rig over a given timeframe."

For instance, Marathon Oil's average time to drill an Eagle Ford well, spud to total depth, averaged 12 days in first-quarter 2015, improving to an average of eight days in first-quarter 2016.

"Put another way, in first-quarter 2015 we were drilling at an average rate of 1,575 feet per day, and with drilling efficiencies, we've improved that to an average rate of 2,300 feet per day in first-quarter 2016."

And while cost efficiencies in the D&C programs garner attention these days, Marathon Oil is focused on reducing operating costs on the production side as well. "We're doing everything we can to improve our lifting costs," Jeff Schwarz, Eagle Ford regional manager for Marathon Oil, said. "We've seen a 14% reduction in our Eagle Ford production costs for first-quarter 2016 compared to the year-ago quarter."

First, the company builds centralized production facilities rather than wellpad facilities. Some 32 large facilities with a capacity of 475,000 bbl/d service up to 80 wells each along its Karnes and Live Oak counties corridor, delivering frack water and produced water and collecting production.

"About 90% of our oil was on pipe in the first quarter. We've taken a lot of trucks off the road."

Adding piping slashed water transportation costs considerably. Approximately 50% of the produced water is moved on pipe.

Gas is delivered to a gas processing facility with a capacity of 270 MMcf/d via 800 miles of gathering pipeline across the field. "It allows us to capture all of the product in one place and be more efficient. It gives us marketing leverage and flexibility as well," said Schwarz.

Marathon Oil works to lower workover costs too, shaving off days from artificial lift installations and lengthening time between rod pump failures. Over the past five quarters, "we've decreased the cost of our workovers by 35% to 60%."

Automating field operations via digital oilfield tools has improved production efficiencies as well by allowing personnel to monitor activity on each well pad remotely from a centralized control center. "We can make better use of data and send people to wells when they need to go as opposed to the old style, in which pumpers make a trip to the well every day."

Personnel costs are a large percent of lifting costs, Schwarz noted, "so if we can ensure that we are sending people to the right places where there is an issue to be fixed or a well to be put back online, then there's less windshield time and more true actionable work activity."

And if that can add just 1% in production efficiency, "that 1% equates to almost another 1,000 bbl/d. It can be pretty impactful."

foot returns are 45% better than offset wells. He anticipates all future completions will adhere to this model.

Targeting the stages has an added cost benefit. "The fact is, we're pumping fewer stages, and that definitely saves us money."

Additionally, two direct offset wells have been given "a kick in the butt" following the engineered stimulation of the newer wells, with one producing three times its previous output with a flat depletion profile.

"While it's early, this flatness indicates the increased perf efficiency—this breaking of rock that we haven't broken in older versions—is contributing. It's exciting."

Lease geometries

Bracken sets the drill/not drill bar at a minimum 30% IRR, and lateral length can make that difference, he said. "If you're at all familiar with Eagle Ford economics, 5,000-foot laterals are hard to make money in; 8,000 footers are substantially easier to earn our rate of return."

Average lateral lengths across its portfolio today average 7,400 feet, with the intent to reach 8,000 going forward.

"Everything we've acquired in the past 24 months has lease geometry which allows us to drill those long laterals. It's imperative even in this price environment. The difference between driving a 5,000- and 7,000-foot lateral in many parts of the play is the difference between earning an inadequate and an attractive rate of return.

"If you're in a $50-oil environment, and you can bring it on stream for $10 [F&D] or less, you're making money. The bottom line is it costs you 25% more to get 62% more reserves. The marginal economics associated with that extended lateral are phenomenal and move the economics on drilling wells in this area from inadequate to highly attractive at strip today."

Lonestar started in the Eagle Ford "with a postage stamp presence" in 2012 but now sports some 35,000 acres in La Salle, Wilson and Gonzales counties. A $100 million drilling partnership with private equity provider IOG Capital has provided acquisition and drillbit capital through the downturn.

"Drilling activity has been important to our continued growth, and that's tricky to do for a company our size when you're trying to preserve liquidity. More than half of our oil is hedged at $77/bbl this year, so we've got good cash flow as well. But in the current environment, having a drilling rig running and being able to execute on farm-ins and giving landowners drilling commitments have been premium value for us."

Bracken uses the JV capital to capture reserves. "If we drill two wells [in the drilling partnership], and it earns 20 offsets and holds them by production, Lonestar owns all the working interest in all the offset wells. That's the goal: to use someone else's money to aggregate assets and hold onto them until pricing improves."

Last year, Lonestar identified expiring acreage held by a major and then used the IOG funds to farm into the position. In a short time, it drilled four wells to hold the acreage. These wells produced more than two and a half times the average offset wells.

"We thought the area had been understimulated and that we could make big improvements. We were able to make that commitment because we had the IOG money and facilitated a significant PUD booking."

Lonestar plans 10 wells in 2016 on a one-rig program, with an eye out for opportunistic acquisitions from financially distressed operators and farm-ins.

Focused intensity

The next step in connecting to more rock is to modify completions so the cluster staging more narrowly focuses the frack energy, Von Gonten iterated.

"If you look at the layering of soft and hard rock in the Eagle Ford, one way to connect that layering is with concentrated energy."

For example, by pumping 80 bbl of fluid per minute over a 300-foot stage, that energy is spread over 300 feet horizontally. "But if you take that same 80 bbl per minute and put it into 150 feet, you're condensing that energy into a smaller space, and that will assist in contacting more rock vertically."

The effective factor is not necessarily volume, but rate. In fact, a condensed focus area might require less volume for equal results.

"The goal is to maximize the energy transferred to the rock to increase the velocity at the fracture tip farther away from the wellbore. Keep the maximum rate you can pump in, but keep it in the smallest area you can. Pump the same volume, but in twice as many stages."

Von Gonten is also evaluating the distance between clusters and the number of shots per cluster. His belief is that closer clusters may be better. "The closer the clusters are together, the more the fracks interfere with each other, and due to the interaction some of them gain additional height—we think that's a good thing." In contrast, frack volumes pushed through noncompeting clusters reach the same height.

Tighter clusters "force the frack to go where it doesn't want to go because fluid has already taken that space. It's forcing height growth."

Perhaps counterintuitively, fewer shots per cluster also result in greater frack height. Pushing the same fluid volume at the same rate through two shot holes rather than three, for instance, focuses the energy more intensely through each hole. Think of it like a rifle vs. a shotgun.

"It's energy management, velocity times pressure," Von Gonten said. "You want to put the maximum amount of energy per hole to create that frack." You also want to minimize the loss of energy associated with near wellbore effects, such as friction.

Some companies want to increase the amount of fluid pumped into the wellbore,

Lonestar Resources Inc. CEO Frank Bracken is custom engineering stage spacing and perforations according to rock variability. "We think we're breaking more rock along the lateral."

Facing page, activity begins before dawn at Sanchez Production Partners' CPF Unit D in Webb County, Texas.

Once seen as a single horizon play, wellbore targeting has opened up three potential pay horizons to Sanchez Energy.

but the only way to increase frack height is through energy at the fracture tip, he said, not by adding volume. “You can keep pumping for a year, and all it’s going to do is increase the horizontal plane; you’re still missing the top and bottom halves of the formation. You leave a lot of reserves behind by doing that.”

And while plug-and-perf is the favored technique today for isolating stages, Von Gonten foresee a time when sliding sleeves become the standard, in spite of the technology’s current mechanical risks.

“With sliding sleeves, you can focus that energy into a two-inch slot, using high rates with low pressure losses. The resulting fracture emanating from the wellbore will also be simpler and less tortuous. That’s ultimately where we need to go. If you can gain 10% more height, that’s a 10% gain in ultimate recovery.”

Teamwork

When Encana Corp. entered the Eagle Ford in mid-2014 via acquisition, average well costs were $8 million for a 5,000-foot lateral. Following aggressive reductions in D&C and facilities costs, a typical well costs less than half today, at $3.5 million. While some of that gain is from price reductions in the service sector, much of it is just plain “blocking and tackling,” said Encana’s Eric Greager.

“It doesn’t get a lot of fancy press, but those are the things that make the biggest gains.”

Encana has taken advantage of the downturn to place its D&C engineering teams on site alongside the supervisors, where they are designing, then engineering, the work in the field.

“In the last six months, with a fewer number of rigs and frack spreads operating, we’ve been able to get the workforce closer to the ground.” As a result, “our nonproductive time has dropped, and we spend less time off the rails than in past cycles. It’s yielded a lot of success.”

On the drilling side, spud-to-rig release times are as low as 8.3 days, benefitting from better application of bit technology, geometry of the bottomhole assembly and fluid rheology, he said.

On the completion side, Encana is testing pinpoint fracturing technologies and the fluid regimes to stimulate wells.

“We thread our geology and geophysics teams into the operation working together with our engineering teams to develop solutions on the cutting edge. What perf-clustering geometry should we use? What rates? How does the fluid rheology play into the pressure drop at the perf clusters? It’s a constant evolution to understand the stimulation scheme.”

One variable the company is investigating is clustering geometry within the stage to maximize the productive clusters per stage. That, Greager said, reduces nonproductive time of completing nonperforming stages, as well as the cost of each stage.

“All of those things help you drive down cost and improve well performance.”

Even within a given wellbore, where to shoot the perforations and how to stimulate the rock are very important, he said.

"We're custom-designing the perf-and-cluster scheme on every single well to understand how many holes to shoot, where they're placed, how many we can combine in a stage. We're always looking at how we can drive out excess stages, because that not only wastes plugs and hardware, but that nonproductive time can be costly to your program."

Thus, while Encana's frack intensity as measured by gallons of fluid or tonnage of proppant is increasing, the overall stimulation cost will likely decrease.

Encana plans to run one rig continuously in 2016, down from five at its peak, and that rig will rotate around its portfolio of 43,000 net acres in Karnes County. The company expects to bring onstream 25 to 35 wells by year-end. The intent is to drill-to-fill—production facilities, that is.

"During this part of the cycle, we're not building new production facilities; we're filling in where we have excess facility capacity to achieve better capital efficiency. That's capacity we've paid for, so we'll come back in with the rig and drill a couple of wells to maintain these facilities at or near full capacity."

The Calgary-based producer tested two Upper Eagle Ford wells this year following two last year, with the most recent ones tracking the same type curve as its Lower Eagle Ford wells.

When the upturn arrives, will Encana keep its on-the-ground engineers?

"We'll likely pull the more senior employees back to Denver as the industry expands on an upcycle, but some of the younger folks, who are gaining invaluable experience, will likely remain in the field as D&C supervisors. We think it's sticky and very effective."

Choked up

Ultimate recoveries can also be greatly affected by how the well is flowed once on production, said Von Gonten. Turns out, those high 24-hour IPs reported by operating companies could be damaging the reservoir.

"The reservoir is sensitive to drawdown. If you put a lot of pressure drawdown on it, you'll lose connectivity to the rock."

The organic matter in the rock is like a compressible sponge, he explained, and as reservoir depletes, the organic pores shrink, and permeability decreases. Von Gonten has observed this phenomenon in his core lab, where he can simulate the pressure of the reservoir downhole. While under pressure, the pore connectivity is higher, allowing hydrocarbon molecules to move freely in the matrix and toward the fracture face. As the pressure is depleted, particularly at the fracture face, the organic matter decompresses, the pores shrink, the connectivity is reduced, and the productivity goes down.

He's tested the concept in the Vaca Muerta Shale in Argentina. There, wells placed on 7/64-inch choke at 500 bbl/d have dropped from 5,000 psi to 2,000 psi but continue to flow the same 500 bbl/d for months.

In contrast, "when we flow an offset well at 1,000 bbl/d, we see a reduction in the EUR."

By pulling a well real hard, he said, "that's lowering pressure and reducing permeability of the reservoir. If you lose permeability at the face of the frack, the well production is 'choked off' at the fracture face."

Instead, "you're better off leaving permeability high so that it transfers pressure and gets the molecules moving. You'll produce your well at a lower rate, but it will stay at that rate for a long time."

Renaissance results

In the company's first-quarter conference call, Chesapeake Energy Corp. CEO Doug Lawler said the company would drill 90 wells this year with an average of 8,000-foot laterals, nearly double the length it was drilling two years previous, with optimized completions.

"Our Eagle Ford [play] has experienced a renaissance; returns have gone through the roof. Our returns today in the Eagle Ford with current costs are about the same as when oil was $80.

"Wells a year ago came on at 500 bbl/d; our latest wells are coming on close to 1,000 bbl/d. If I'm fighting for capital, that's the area I want to send it first."

Noble Energy reported two enhanced wells in its Briscoe Ranch acreage in Dimmit County with IP 30s of 2,200 and 3,500 boe/d on an average 4,900-foot lateral. These tested tighter cluster spacing and higher sand concentrations.

"These wells are outperforming our 1 MMboe type curve," said Noble executive vice president of operations Gary Willingham in the company's first-quarter call. They "were completed with 2,000 pounds of proppant per lateral foot, and the better-performing well was designed with tighter cluster spacing."

Sanchez's Heinson said it's just a matter of time before the Eagle Ford comes back to robust activity. "When you look at basin by basin IRRs, the Eagle Ford always rates up there with the Permian and the Scoop/Stack."

The quality of the Eagle Ford reservoir as a resource play is legacy—high pressure, low clay content, good porosity, good fluids and good permeability.

"If you consider our flow equation, everything is good," noted Von Gonten.

Now that the industry is beginning to understand the layered nature of the Eagle Ford, "recoveries should go up 30% when we fine-tune our lateral positions, and when we change our frack designs, I think that's another 30%.

"Let's design the best landing point and the best frack design to maximize the recovery. There's so much more to do." □

During the low commodity price cycle, Encana Corp. has placed its D&C engineering teams in the field alongside supervisors. "Our nonproductive time has dropped, and we spend less time off the rails than before," said Eric Greager, vice president and general manager of western operations.

Marathon Oil is focused on maximizing efficiencies on the production side of operations. "We're doing everything we can to improve our lifting costs," said Jeff Schwarz, Eagle Ford regional manager.