Mid-Continent Operators Test Dewatering Techniques, New Frac Technology

By Dan Holder

Energy prices cycle up and down with heartbreaking inconsistency, but the oil and natural gas industry can rely on one constant: technology and techniques devised to overcome one field's challenge will quickly be adopted by others to satisfy totally different needs.

Independents have a long history of moving into U.S. fields as majors leave, applying new techniques and economically exploiting the remaining reserves. Companies in the Mid-Continent region are adhering to that tradition and adapting existing practices to new situations.

New Dominion LLC, based in Stillwater, Ok., is applying refinements of technology developed for coalbed methane production to dewater saturated oil and gas fields, making new production of conventionally produced and depleted fields economical. Three Oklahoma partners, John F. Special, Chris McCutchen, both of Stillwater, and David J. Chemicky of Tulsa, founded New Dominion in July 1998. New Dominion is the state's fastest-growing oil company ranked by daily oil production, the company reports. Together with its alliance partner, Altex Resources Inc., who also worked to develop this technology, they are collectively the state's largest crude oil producers.

Much of the attention among North Texas natural gas producers is on developing the Barnett Shale. Pitts Oil Company, based in Dallas, has been involved in the play directly and indirectly for a number of years, including participation with Mitchell Energy's earliest wells. The company, started by Frank Pitts 60 years ago, is successfully going back into wells with new fracturing technology to access new reserves.
Dewatering Success

New Dominion is drilling in the Hunton Limestone Formation in central Oklahoma, an area that has had limited conventional production in the past because of high water saturation, observes John Special. When New Dominion took over the fields and began dewatering in July 1998, one well’s average daily production using a small submersible pump was 5-10 barrels of oil and 300 Mcf of gas, with 1,600 barrels of water. Over 16 months, after offset development wells were drilled to dewater the surrounding reservoir rock, Special says that well began producing less than 600 barrels of water a day, and was placed on a beam pump. Daily oil production increased to more than 80 barrels, and gas production jumped to 500 Mcf/d.

“As far as dewatering this field, David (Chernicky) came up with that idea, but it has evolved from some Red Fork production in Northern Oklahoma that we all worked on, together and separately,” Special, co-manager of New Dominion, explains. “We had some Hunton production near Carney, Ok., and we sold it to David and his partners through Altex Resources. They figured out the way to dewater it and (inject) the water into the Arbuckle. The disposal wells are the key to the project. New Dominion has spent a lot of time and money refining the disposal technology. If we didn’t have good disposal wells, the dewatering method would not be as successful.”

The Hunton Formation is widespread throughout most of Oklahoma, Special indicates, adding, “We and others are trying to generalize this dewatering concept to other areas of Oklahoma, and possibly even to other states. There has been limited but encouraging success. It doesn’t work everywhere. Just because you find the Hunton doesn’t mean that you have a dewatering project.”

New Dominion’s success in oil and gas production after dewatering depends on six components, the company explains:

- Correct geological assessment of the reservoir;
- Abundant and economic three-phase electric power;
- A high-volume gas gathering and processing system, which is often nonexistent in the areas around these types of reservoirs;
- A water disposal system capable of handling the high fluid volumes produced;
- A large front-end capital investment to ensure that enough wells are drilled in the initial phase to create synergistic interaction between the wells and decrease the producing water/oil ratio markedly as field development continues; and
- A well-trained field staff able to safely maintain a highly loaded and challenging mechanical system.

“Production from the Greater Carney Field averages 7,000 to 8,000 barrels of oil, and more than 60 million cubic feet of gas a day. This is produced by four primary operators,” Special adds. “Compared to last year, we are still on an incline, although since we had such tremendous early-on success it is hard to maintain that rate of growth. When we add wells, we are flattening our curve and not adding a lot of daily production. We have finally reached the size where it’s like a Wal-Mart: it’s hard for Wal-Mart to substantially increase its sales by adding a few new stores because it already has so many stores. When we discuss doubling production we are really talking about doubling the number of wells.”

Continued dewatering eventually changes the dynamics of the field, he reveals. “There is so much gas in solution in these reservoirs, that as you dewater them, you make large amounts of gas along with some oil. As the water diminishes, the oil decreases until the final stage is a gas well. New Dominion starts a new well on a large submersible pump. Once or twice during the well’s life the submersible pump may be down-sized, and in the final phase we install a beam pump.”

Electrical Demands

In the Lincoln County project, which has 64 wells, New Dominion’s total infrastructure investment exceeds $28 million. This infrastructure includes water disposal facilities, electrical construction, tank complexes, leasehold/acquisition costs, drilling costs, and completion costs. Electricity accounts for approximately 50 percent of the $6,000 a month average operating cost a well.

“You certainly need a good dependable and expandable supply of electricity, because if you do have some success, you will need more electrical power,” Special relates. “The electric cooperatives here in Oklahoma require more than a year’s advance notice to order the various components. We are the largest customer for Central Rural Electric Co-op in Stillwater, Oklahoma and Canadian Val-
ley Electric Co-op in Seminole, Oklahoma. Their engineering departments have been very accommodating, as far as helping us with our planning and giving us advance notice when there is going to be a shortfall in power, line construction, and other key components of the electrical infrastructure.”

For all of New Dominion’s field operations, the monthly electric bill exceeds half a million dollars, Special notes. “Any time you handle as much saltwater as we handle, over 100,000 barrels a day throughout our operations, it is a very costly aspect of our business,” he details.

New Dominion has considered adding cogeneration facilities in its fields, but so far Oklahoma’s power system has been able to provide the electricity it needs.

Water Disposal

New Dominion’s massive water disposal requirements present problems, but Special explains that the company’s solutions don’t rely on large amounts of high technology. “It’s just that everything is bigger, and of course more expensive, because we are handling saltwater, which is hostile to metals, so we have to coat almost everything,” he says, adding: “To prove up one of these projects, you have to drill and complete a $500,000 disposal well before you test your idea. That was not very commonplace in central Oklahoma before this play kicked off, because you have a lot of independent operators who perhaps were not that well capitalized.”

The company designed the saltwater disposal wells anticipating high fluid volumes in the dewatering operation, Special details. New Dominion sets 9 5/8 inch casing through the Hunton to the top of the Arbuckle Limestone, with well depths as much as 2,500 feet below the base of the Hunton, in the 6,000-7,500 foot range. The company then runs 7-inch internally coated casing through the outer casing. Each disposal well can handle 15,000-20,000 barrels of water a day on vacuum and more than 25,000 bbl/d if equipped with a high-volume, low-pressure centrifugal pump to overcome friction in the tubing string.

New Dominion perforates the entire zone, typically at one shot a foot, and uses an acid fracture with sand or rock salt as a diversion agent. To interpret reservoir quality, the company says it uses standard triple-combination open hole logging suites.

Production Support

To cope with the high volume of gas and liquids produced, New Dominion designed the gas-separation and water-separation facilities on site, as well as refinements to the horizontal free-water knock-outs. “We typically have two or three separators at the wells to separate the large amounts of gas from the fluids, and then we use a free-water knock-out to separate the water from the oil,” Special reveals. “Our company worked with the manufacturers to design these vessels with larger intakes to handle the large amounts of gas we are producing.”

New Dominion has also been extensively involved with the manufacturers of submersible pumps, helping redesign pump stages to deal with the large amounts of gas in solution.

High production rates depend on fracturing the formation, Special indicates, adding that the high-water environment does not affect the frac.

“Typically, we don’t selectively perforate our zones, since we know that there is oil, water and gas smeared throughout the entire interval. We perforate one shot a foot, and therefore we have gone to dual-stage frac’s, where we may perforate in the bottom 60 feet of the zone, stimulate, and then set a plug. We then perforate the top 100 feet of the zone, just to ensure that the entire zone is broken down and treated. We frac at fairly high rates, between 30-70 barrels a minute,” he says.

Despite the enormous upfront costs of the saltwater disposal wells, Special indicates that the company has had little problem raising the needed capital. “We had a good base of production initially and very cooperative banking relations with the Bank of Oklahoma and Stillwater National Bank,” he says. “They have been in on the play since the beginning, so establishing a comfort level was not that difficult. As we proceeded, they grew in their understanding of what we were doing.”

One factor in the banks’ decision to support New Dominion is the size of the reserves targeted by all the operators in the field. Special estimates them at more
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than 10 million barrels of oil in the Carney area, and between 60 billion and 80 billion cubic feet of natural gas. Although operating costs, especially electricity, are high, Special indicates that New Dominion's operation can be profitable even at $12 a barrel oil and $1.75 a Mcf gas. "It takes a lot of hard work and long hours. A dedicated staff and knowledgeable field personnel are an absolute necessity. If you see oil and gas in the samples and the fluid flow conditions are favorable, we run the submersible pump, evaluate the results, drill a few offsets, and pretty soon an oil field develops if the other necessary criteria are present."

"We are optimistic about the dewatering technique. I am not sure how optimistic I am regarding oil and gas prices," Special muses. "Once you become accustomed to $25-$30 a barrel oil and $4-$5 gas, the cyclical market can once again show us how quickly oil and gas prices can fluctuate."

**Fracing Barnett Shale**

The Pennsylvanian Conglomerate underlying much of North Texas has been the mainstay of the Boonsville Gas Field, which has been producing for more than 40 years. Interest in the underlying Barnett Shale took off in the early 1980s, and now Pitts Oil Company of Dallas is taking a second look at those early Barnett jobs, using improved fracturing technologies to improve, or even start, production from a number of wells.

The companies working the Barnett Shale keep 25 rigs in the field, reports David Martineau, Pitts exploration manager, and there probably have been 800-900 wells drilled to date, a number that is continuing to increase.

Most of those operations focused on infill drilling and refracturing earlier wells, Martineau reports. Operators in the early '80s typically used 300,000 pounds of sand and 300,000 gallons of water in their frac jobs, later moving to increased use of sand, sometimes pumping 1.5 million pounds, and up to 1.5 million gallons of fluid downhole.

"This gel-frac was the predominant fracing technique until three years ago, when water fracs, or as they are sometimes called, light sand fracs, were introduced," he notes. "You would still put a million gallons of water in there, but instead of a million pounds of sand, you would put 100,000 pounds of sand, virtually one-tenth the amount of sand you had before. You also then eliminated the gels, which carry the sand in formation."

"Gels have to break at a certain time so the sand falls out. If the gel doesn't break, you could end up with a mixture someone once referred to as 'bubble gum,' so the well maybe did not perform as well as they thought it should, based on comparable offset wells," Martineau reveals. "In most cases, the gel worked fine, and the wells have done very well for 15 years. But in a lot of cases, they didn't. So operators have gone back in, and are doing an extensive refrac program on wells that were gel fraced the 1980s and early 1990s."

**Geological Factors**

Pitts Oil's main production zone, concentrated in the eastern portion of the basin, is 7,000-8,700 feet deep, almost the deepest section of Barnett Shale, Martineau explains. Underneath Denton

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County, the formation gets deeper going to the east and north. Producers are looking to extend the play in all directions except east, where the Munster Arch Uplift limits production possibilities.

Thinning of the formation to the west and underlying water tables hampers exploration and development efforts, Martineau says. The Barnett Shale, 300 feet thick in Wise County, thins to half that under Palo Pinto County, and continues thinning as it continues west. However, the western edge of the formation is significantly shallower, he adds. In Palo Pinto County, it's about 4,000 feet deep, while under Wise County it's 7,000 feet down, and 8,500 feet in Denton County.

Aside from varying in depth, the formation also has an upper and lower component for most of its length, explains Martineau. “The upper Barnett is about 100 feet thick, and the lower Barnett ranges from 300 feet to 600 feet. As you dip to the east-northeast, you get a thicker section moving to the northeast. They originally completed most of the wells only to the lower Barnett.

“People who have a lower Barnett completion are coming back in and opening the upper Barnett. There is a different frac gradient between the upper and lower, which is why they couldn’t commingle them initially. The people who are drilling today, frac the lower Barnett with water, set a plug in the Forestburg Lime, and then frac the upper. They then drill out the plug and commingle the zones. That is the prevalent completion technique.”

Another complication facing those working the western portion of the Barnett Shale is that where the play is active, it is above the Viola Formation, Martineau continues. “As you move westward, the Barnett Shale sits on top of the Ellenberger Formation. The key question is, can you frac with these massive fracs and keep the frac from growing down into the Ellenberger, which traditionally in this area has primarily been water? Otherwise you end fracturing into water.”

Operators are drilling wells in Parker, Hood, Palo Pinto, Johnson and Tarrant counties, attempting to come up with techniques to commercially produce from the Barnett without penetrating the Ellenberger, relates Martineau. The advantages out west, he notes, are that the Barnett is closer to the surface, so wells are cheaper, and because the Barnett has a single zone there, only one fracture job is needed.

“So your well, rather than coming in at 1 million cubic feet a day, comes in at 200,000-300,000 cubic feet a day,” he notes. “There are several wells that are stepping out and attempting to come up with a good technology for fracturing where the Barnett sits on top of the Ellenberger and make a commercial well. It is going to happen, but if these gas prices continue to fall, you are not going to see quite as many experiments.”

New Fracture Lines

An important component of reworking the old wells is getting the fracture job to open different parts of the reservoir, Martineau continues. “It’s amazing, but what happens is that when you drain a reservoir and release the pressure, it closes up. When you start refracing, if it can find a new fracture, you go into the new fracture area and not into the old one.

Unlike most areas involved in exploration and production, three-dimensional seismic has a minimal role to play in North Texas, he reveals, principally because the fractures are typically undetectable hairline fractures. The only reason operators would run 3-D seismic, Martineau adds, is to avoid drilling next to a fault.

“There are some faults that run through the area, and unfortunately when you happen to drill next to one—and most of these are vertical faults so they don’t really cut the well bores—you can have two wells side by side, and can have a complete section in both, but there will be a fault running between them. When you start doing a massive frac job, the frac gets into the fault, so that you have an ineffective frac job. You really don’t get your frac fluid in the zones you want. The only reason we would shoot 3-D seismic would be to determine where the faults are, to stay away from them.”

Economic Factors

Using water fracs instead of gel fracs reduces the costs of fracturing wells approximately $150,000, Martineau indicates. Unfortunately, he remarks, a doubling of contract drilling day rates in the last couple years as the play has heated up, has consumed that savings.

“The savings you had with the change from gel fracs to water fracs has been eaten up by increased drilling and completion costs,” he confirms. “It is not just the frac companies. The cementing companies, the logging companies, and

The Barnett Shale underlying much of North Texas is giving up more natural gas thanks to new fracturing technologies used by a host of operators, including Pitts Oil Company of Dallas. Here, BJ Services of Mineral Wells undertakes a frac job on a Denton County well. Photo courtesy BJ Services.
everybody went up. Drilling contractors doubled their rates; the other people went up anywhere from 10 to 30 percent. So we are right back to the same costs we had before.”

Another difficulty is the nationwide scarcity of rigs, Martineau points out. Oil and gas operators are trying to buy them or lure crews and equipment from West Texas and other states. Those with rigs under their control are “in the driver’s seat,” he says, because they can negotiate for leases, although very few leases are available in the active portion of the play.

**North Texas Plans**

Pitts Oil doesn’t have a long production history reworking Barnett Shale wells, but it just began operations in the area in late 1999, Martineau relates. He adds that the history of using in this play water fracturing technique is only three years old, further limiting estimates on future production. A 1998 Oil & Gas Journal report estimates that the Barnett Shale has potential reserves of 10 trillion cubic feet, but he notes that the new fracturing technology has boosted those reserve estimates, as well as the extent of future production.

“I went to the Society of Petroleum Engineers annual meeting in Dallas this past year,” he recalls. “They had a half-day seminar on refracturing. The Barnett Shale was one of the examples of what happens when you frac, and can bring the well back on production at three-fourths to almost 100 percent of what it was before. So you have obviously fraced into something new. This play has the potential, down the road, of going back in and refracing the zones you are currently in.

“We don’t have any experience with water fracs over a 20-year life to say that after I have depleted this zone and produced a billion cubic feet of gas, that I can frac it and get another billion. Down the road, a lot of people may say, ‘Yes, it definitely can be refraced once, maybe even twice.’”

Pitts Oil will continue to work its acreage in the Barnett Shale, and Martineau says the company expects to keep two-three rigs in continual operation for the foreseeable future. With two rigs running, he calculates Pitts Oil has at least a four-year drilling program for its 35,000 acres. The company is now drilling on 80-acre spacing. After analyzing drainage patterns, he says it may try experimental drilling on 40-acre spacing.

“We are very excited about the play, obviously, and we are very fortunate to have a pretty good acreage position held by production,” Martineau says. “As the play moves farther to the north into Montgomery County, though, because of the timing and depth of burial, it looks like it turns into oil.

“Producing oil out of shales has always been a difficult thing to do, so it is in its infancy stage now. We completed a well last year in the Barnett for oil, and it looks like it is going to be a pretty good well. It has already produced around 10,000 barrels of oil, and it started a huge play.”

The Barnett Shale formation is drawing a lot of attention now, but Martineau calculates that future natural gas prices will determine how long that attention lasts. “Everybody hoped we would have a new baseline of $4.50-$5.50 to keep up with the increased costs. Nobody saw $9, but they sure didn’t see it dropping back to $3,” he says.

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**EIA**

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is the first in which U.S. demand is expected to average more than 20 MMbbl/d.

Revised data indicate that total petroleum products demand in the first quarter this year averaged 19.86 MMbbl/d, up 570,000 bbl/d from the same period last year. EIA continues. “Much of that growth is attributable to the first-quarter fuel switching to petroleum products from other fossil fuels—primarily natural gas—in the power-generation sector,” the agency says. “In addition, Y2K-related concerns that depressed first-quarter 2000 deliveries contributed to that year-to-year period growth.”

The second quarter, in contrast, EIA says, registered only a 150,000 bbl/d increase. Moreover, the agency predicts, growth in total petroleum demand will average less than 70,000 bbl/d for the second half of this year. For 2002, EIA says it expects somewhat stronger economic growth to offset the reversal of fuel switching seen in early 2001, yielding another net gain in U.S. oil demand of 1.4 percent.

**Natural Gas Demand**

EIA projects U.S. natural gas demand will grow by 1.6 percent this year, compared with estimated 5.0 percent growth in 2000. This is partly the result of the sharply lower economic growth rate expected this year relative to last year, (1.8 percent compared to 5.0 percent), the agency explains. In addition, it says the negative impact on gas demand of high prices at the beginning of the year, and the likelihood that weather-induced demand increases will be smaller this year (particularly in the fourth quarter) contributes to lower demand growth in 2001.

“Growth in 2002 is expected to rise by 4.4 percent as the economy picks up again from its dip in 2001 to a growth rate of 2.5 percent, and as a much improved supply situation keeps prices in check and prevents the kind of massive fuel switching seen in early 2001,” EIA states.

The agency notes that industrial and power generation demand for natural gas fell during the first six months of 2001 from year-ago levels, but says it expects that to reverse itself by October as a result of lower prices and new gas-fired power generation requirements. Industrial demand growth, which was generally