HARTENERGY

Bakken and Niobrara Shales

The Playbook

A supplement to

Oil and Gas Investor

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UNCONVENTIONAL OIL & GAS CENTER

Bakken and Niobrara Shales:
The Playbook

A supplement to *Oil and Gas Investor, E&P,* and *Midstream Business*

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Table of Contents

Rig hands make a connection on a Niobrara well in the Denver-Julesburg Basin. *(Photo by Lowell Georgia, courtesy of Hart Energy's* Oil and Gas Investor*)*

WEB EXCLUSIVES

OHIO AND OIL GROW TOGETHER

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EXCLUSIVE SERIES: MARKET INTELLIGENCE: MIDCON OPERATORS PUSH FOR RIG RATES REDUCTIONS

This report is part of Hart Energy's proprietary *Market Intelligence* series. Hart Energy researchers interview industry participants in these specific sectors to bring our subscribers real-time, actionable information from the field.
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AN ENVIRONMENT FOR CORPORATE M&A

There are still a number of large operators with strong cash positions who might be willing to deploy capital to acquire companies at reduced prices.
UGcenter.com

TRACKING LEGISLATION THAT COULD AFFECT MIDSTREAM

Expect a generous helping of gridlock, Stratas Advisors' John Kneiss said.
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MOST READ ON THE WEB

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2. Hamm: Oil Will Recover Once Producers Stop Spending
3. Exclusive Series: Market Intelligence: Midcontinent Rig Rates Under Pressure
4. Chevron Announces $35 Billion Budget For 2015
5. Shale Plays Challenge Gas Processing Design

SPECIAL REPORTS AND RESOURCES

Emerging Plays: Springer Shale
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Drilling Highlights
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In recent years, billions have been earmarked for Wattenberg Field where operators have been developing and expanding the Niobrara tight-oil play. *(Photo by Brian Payne, courtesy of* Oil and Gas Investor*)*

Sweet-spotting Critical in the Bakken

The U.S. Williston Basin accounted for about 25% of the domestic oil production at year-end 2014.

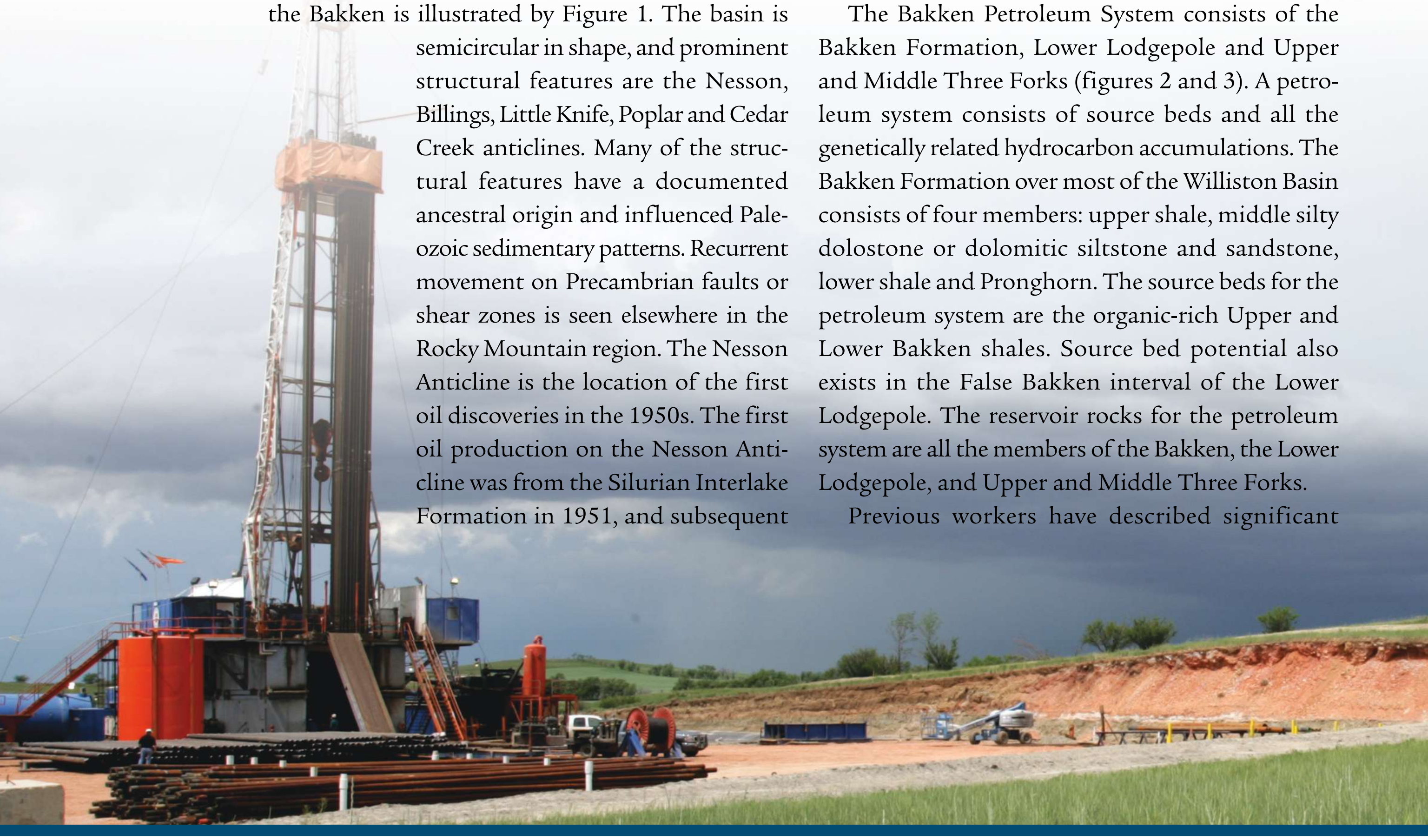
By Stephen A. Sonnenberg
Colorado School of Mines

The Mississippian-Devonian Bakken Petroleum System of the Williston Basin is characterized by low-porosity and low-permeability reservoirs, organic-rich source rocks and regional hydrocarbon charge. The unconventional play is the current focus of exploration and development activity by many operators.

The structure of the Williston Basin at the top of the Bakken is illustrated by Figure 1. The basin is semicircular in shape, and prominent structural features are the Nesson, Billings, Little Knife, Poplar and Cedar Creek anticlines. Many of the structural features have a documented ancestral origin and influenced Paleozoic sedimentary patterns. Recurrent movement on Precambrian faults or shear zones is seen elsewhere in the Rocky Mountain region. The Nesson Anticline is the location of the first oil discoveries in the 1950s. The first oil production on the Nesson Anticline was from the Silurian Interlake Formation in 1951, and subsequent oil production was established from the Mississippian Madison group (the main producer in the basin). The Williston Basin produces mainly oil from several Paleozoic reservoirs (Figure 2). The probable source rock to reservoir rock petroleum system is illustrated by Figure 2. Seven different petroleum systems have been identified in the Williston Basin.

The Bakken Petroleum System consists of the Bakken Formation, Lower Lodgepole and Upper and Middle Three Forks (figures 2 and 3). A petroleum system consists of source beds and all the genetically related hydrocarbon accumulations. The Bakken Formation over most of the Williston Basin consists of four members: upper shale, middle silty dolostone or dolomitic siltstone and sandstone, lower shale and Pronghorn. The source beds for the petroleum system are the organic-rich Upper and Lower Bakken shales. Source bed potential also exists in the False Bakken interval of the Lower Lodgepole. The reservoir rocks for the petroleum system are all the members of the Bakken, the Lower Lodgepole, and Upper and Middle Three Forks.

Previous workers have described significant



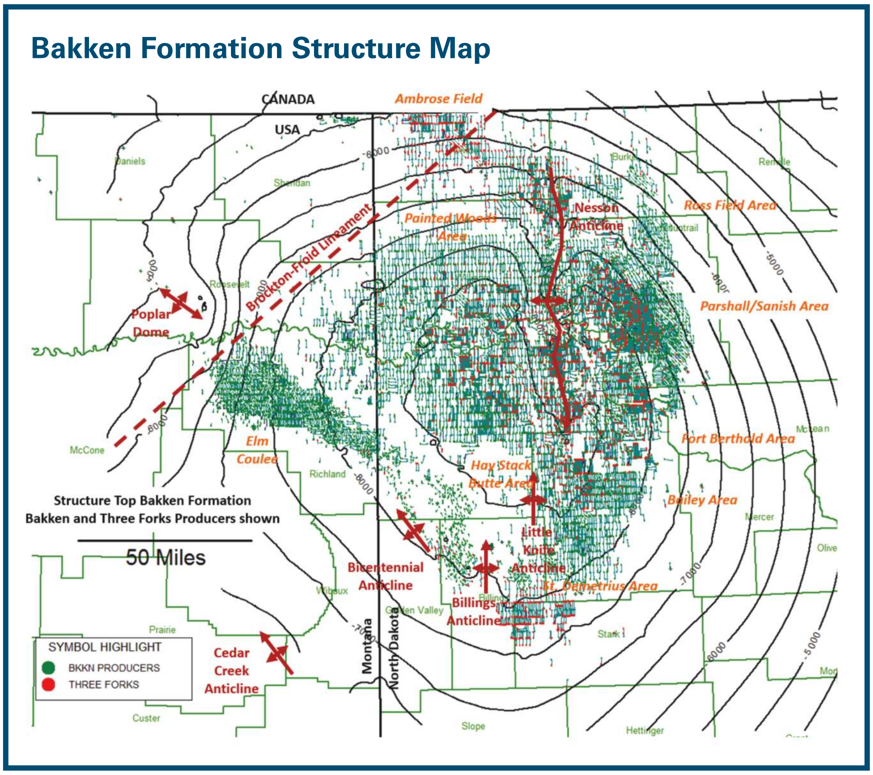


Figure 1. A structure map on top of the Bakken is shown. The contour interval is 500 ft. Prominent structural features in the Williston Basin include the Poplar, Cedar Creek, Billings, Bicentennial, Little Knife and Nesson anticlines. *(Images by Stephen A. Sonnenberg unless otherwise noted)*

oil, 3.5 Tcf of gas and 281 MMbbl of NGL.

The Bakken Petroleum System is thought to have created a continuous accumulation in the deeper parts of the Williston Basin. A continuous accumulation is a hydrocarbon accumulation that has some or all of the following characteristics: pervasive hydrocarbon charge throughout a large area; no well-defined oil- or gas-water contact; diffuse boundaries; commonly abnormally pressured; large in-place resource volume but low recovery factor; little water production; geologically controlled sweet spots; reservoirs commonly in close proximity to mature source rocks; reservoirs with very low matrix permeabilities; and water occurring updip from hydrocarbons. The Bakken Petroleum System meets all of these characteristics.

Bakken source rock potential, and estimates of oil generated from the petroleum system range from 10 Bbbl to 400 Bbbl. The U.S. Geological Survey's (USGS) 2013 mean of technologically recoverable resource estimates for the Bakken Petroleum System is about 7.4 Bbbl of oil, 6.7 Tcf of gas and 527 MMbbl of NGL. The technologically recoverable resource estimates for the Bakken Formation are 3.6 Bbbl of oil, 3.1 Tcf of associated/dissolved natural gas and 246 MMbbl of NGL. The technologically recoverable resource estimate for the Three Forks is 3.7 Bbbl of

Many of the reservoirs in the Bakken Petroleum System have low permeability. Productive areas or sweet spots are localized areas of improved reservoir permeability through natural fracturing or development of matrix permeability, or a combination of both. The Bakken Petroleum System is a continuous system with no real boundaries between fields (Figure 1). Total Bakken and Three Forks production

With storm clouds on the horizon, Patterson-UTI Rig #180 drilled a Bakken well for Continental Resources in North Dakota. *(Photo by Lowell Georgia, courtesy of Hart Energy's* Oil and Gas Investor*)*

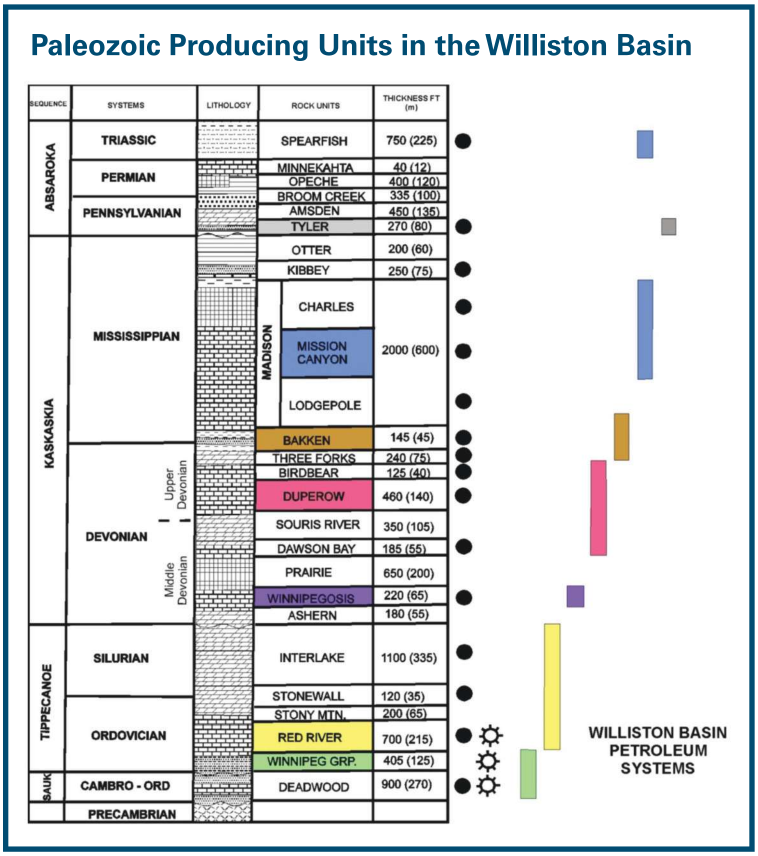


Figure 2. A stratigraphic column for Paleozoic producing units in the Williston Basin is shown. Producing units are shown by oil and gas symbols. Sedimentary sequences following Sloss (1963) are indicated. Thickness of stratigraphic units is indicated in the column to the right (ft/m). Oil and gas symbols indicate producing formations. Petroleum systems are modified from USGS data.

through December 2014 was about 1.3 Bbbl of oil and 1.3 Tcf of gas from 12,051 wells (Figure 4). Thus the petroleum system easily meets the definition of a giant accumulation (500 MMbbl of oil). Total Bakken production through December 2014 was 1 Bbbl of oil and 1 Tcf of gas. Total Three Forks production through December 2014 was 263 Mbbl of oil and 294 Bcf of gas. The most notable sweet spot areas are Elm Coulee, Sanish and Parshall fields. Field names are abundant through the continuous accumulation but no real barriers exist between the fields. The U.S. Williston Basin accounted for about 25% of domestic oil production at year-end 2014.

This paper summarizes the regional geology of the Bakken and Three Forks formations in the Williston Basin.

Bakken exploration history

The Bakken Formation of the Williston Basin has seen three cycles of exploration and development since the 1950s (Figure 4). The first cycle was the Antelope Field discovery and development (Bakken and Three Forks vertical drilling). The next cycle was the Upper Bakken Shale Billings Nose "edge play" (vertical and horizontal drilling for the Upper Bakken Shale). The last cycle was the Middle Bakken-Three Forks horizontal play.

The earliest discovery occurred in the Antelope Field of North Dakota in 1953, and development continued into the 1960s. Sixty-three wells targeted the Bakken and Upper Three Forks (referred to as the Sanish member) on a tightly folded structure. The Bakken and Upper Three Forks are low-permeability, fracture-enhanced reservoirs in the Antelope Field with fracturing related to the tight fold. The wells were drilled vertically and after a sand-oil fracture stimulation treatment were capable of producing an average of 209 bbl/d of oil. The Antelope Field has produced 11 MMbbl of oil and 20 Bcf of gas from the Three Forks-Bakken interval. Average cumulative production per well is 550 Mbbl of oil and 1.4 Bcf of gas. Following the Antelope discovery, exploration proceeded slowly. All three members of the Bakken and the Upper Three Forks were perforated in the Antelope, and production established these formations as petroleum reservoirs in the basin.

The next significant discovery in the Bakken was by Shell in the Elkhorn Ranch Field in 1961 (Billings Nose area, figures 1 and 4). The area occurs along the southwest margin of the Bakken depositional basin in the general area of the Billings Nose. The Upper Bakken Shale was completed in the well as a secondary objective after the deeper primary objective, the Red River zone (Ordovician), was unsuccessful. The Elkhorn Ranch well was very significant in that it showed that significant reserves could be found in the Upper Bakken Shale. Because of product prices and remoteness of the area, the next Bakken well was not drilled until 1976. This area then became known as the "Bakken Fairway" area. Wells drilled in the fairway targeted the Upper Bakken Shale and other adjacent Paleozoic horizons (both shallower and deeper). Fracture density increases where the Bakken thins. Sand-oil fracture stimulation treatment was used on these wells.

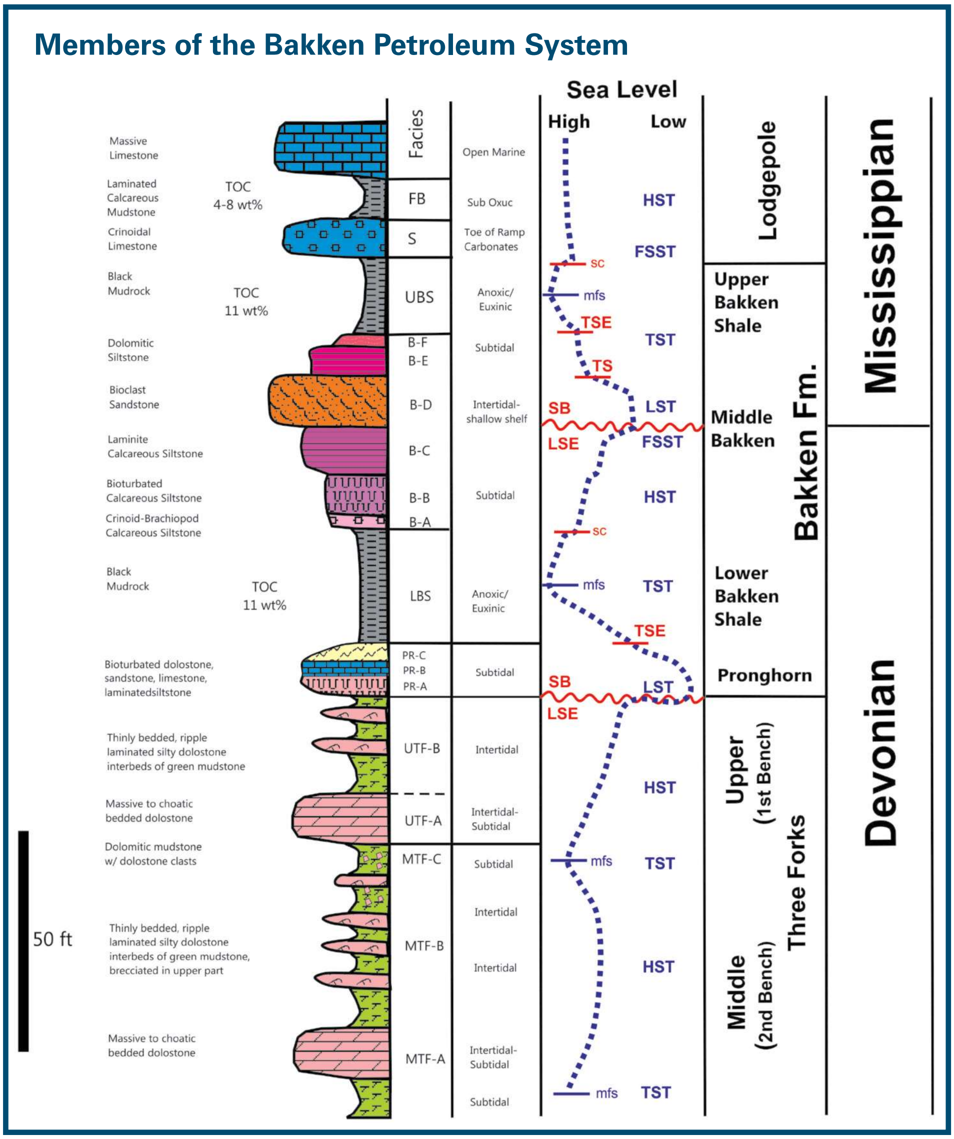


Figure 3. The diagram illustrates members of the Bakken Petroleum System. Reservoirs are the Middle and Upper Three Forks, the Middle Bakken and the Scallion member of the Lodgepole.

Horizontal drilling in the Upper Bakken Shale commenced in 1987 in the fairway area. The first horizontal well, drilled by Meridian, was the #33-11 MOI well (sec. 11, T143N, R102W, Elkhorn Ranch Field), which had a horizontal displacement of 2,603 ft in the Bakken. The well was completed for 258 bbl/d of oil and 299 Mcf of gas, and production was remarkably stable for the first two years. The success of this well set off the horizontal drilling phase of the Upper Bakken Shale. The play continued into the 1990s with more than 20 operators. Product prices declined significantly in the 1990s and, along with the somewhat unpredictable production in the Upper Bakken Shale, brought this phase to a close. The fairway play met with mixed results. Good producing wells often were offset with poor producing wells. In addition, some pressure depletion and cross-well communication were reported.

Because of mixed results in the fairway trend and low product prices, the Bakken returned to the status of being a secondary objective type of a reservoir rather than a primary objective of exploration. This status changed with the discovery of significant reserves in the Middle Bakken in the Elm Coulee Field. The discovery and development of the Middle Bakken have resulted in the most significant of the exploration cycles to date.

The Elm Coulee Field was discovered in 2000 with horizontal completions in the Middle Bakken. The field is located in the western part of the Williston Basin in northeast Montana (Figure 1). Prior to horizontal drilling in 2000, the area had scattered vertical well production (marginal to uneconomic) from the Bakken. The Bakken was a secondary objective for wells targeting deeper horizons. Horizontal drilling began in the field in 2000, and to date, more than 1,500 wells have been drilled. The EUR for the field is more than 200 MMbbl of oil. Cumulative production from the Elm Coulee area from the Bakken through December 2014 was 152 MMbbl of oil and 136 Bcf of gas. Horizontal drilling and fracture stimulation of the horizontal leg are key technologies that enable a low-permeability reservoir to produce. The original drilling and spacing unit at Elm Coulee was a 640-acre unit. Wells were drilled using bilaterals or trilaterals in a section and were then fracture

Total Bakken and Three Forks Production in the Williston Basin

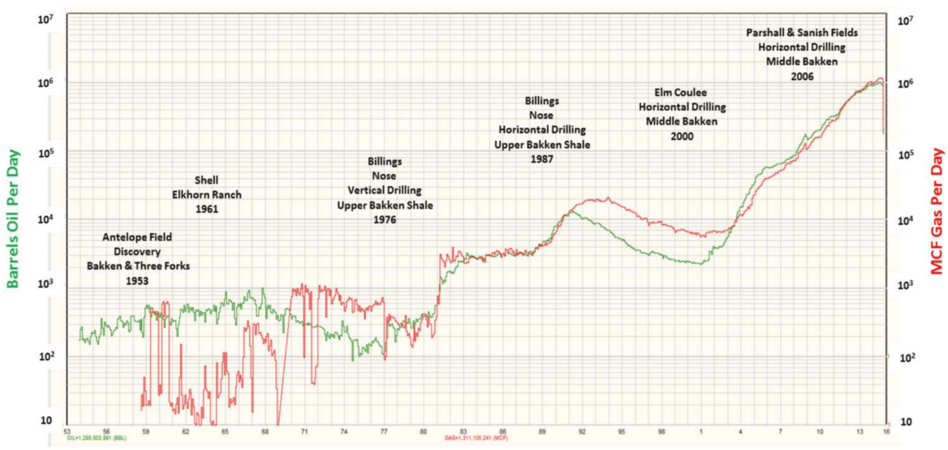


Figure 4. The total U.S. Williston Basin Bakken and Three Forks production is illustrated. The current cumulative total is about 1.3 Bbbl of oil and about 1.3 Tcf of gas.

stimulated with one hydraulic fracture stimulation stage (which became known as the pump-and-pray type of fracture stimulation). Stratigraphic trapping plays a key role at Elm Coulee. Horizontal wells in the Elm Coulee Field mainly target the B facies of the Middle Bakken (Figure 3). The unit is dominated by dolostone. The mineral composition in the main pay interval is 50% to 60% dolomite, 30% to 35% quartz, 10% feldspar and 5% clay.

The Elm Coulee discovery and development prompted operators to also target the Middle Bakken in North Dakota. Prior to Elm Coulee, most operators targeted only the Upper Bakken Shale. The expansion of the play into North Dakota is underway and has resulted in many new discoveries including the Parshall and Sanish fields. The new discoveries in North Dakota suggest the existence of an extremely large unconventional resource play. Product prices will probably influence this cycle, too.

The Parshall Field, located on the east side of the Nesson Anticline, was discovered in 2006 with horizontal completion in the Middle Bakken. EOG drilled and completed the 1-36 Parshall (sec. 36, T 150N, R90W) for 463 bbl/d of oil and 128 Mcf/d of gas. Through December 2014, the field has produced about 94 MMbbl of oil and 46 Bcf of gas from 346 wells completed in the Bakken. This field illustrates that significant production from the Middle Bakken and Three Forks exists in North Dakota. The field connects to the Sanish Field to the west and the Ross Field to the north. By the time Parshall was discovered, multistage fracture stimulation had been tried and tested in the Barnett Shale play of the Fort Worth Basin. Therefore, during the development of the Parshall Field, the multistage hydraulic stimulation in the Williston Basin was developed. Fracture stages originally numbered about 10 but have evolved up to 40.

The Sanish Field also was discovered in 2006. Whiting drilled the discovery well, the 44-1 Bartleson (sec. 1, T152N, R93W). Through December 2014, the field has produced about 101 MMbbl of oil and 74 Bcf of gas from 592 wells completed in the Bakken and Three Forks.

Horizontal wells in the Parshall-Sanish areas target specific facies (C, D and E) of the Middle Bakken (Figure 3). Production is related to fracture development and matrix development in the Middle Bakken. The original oil in place in the Parshall greater area is estimated by various operators to be 8 MMbbl to 11 MMbbl per section for the Bakken and 4 MMbbl to 6 MMbbl per section for the Three Forks. Wells are drilled on either 1,280-acre spacing units or 640-acre spacing units. EURs for the Bakken are 600 bbl to 900 Mbbl of oil per section; EURs for the Three Forks are 350 bbl to 500 Mbbl of oil per section. The recovery factor for the tight reservoirs is about 8%. Because of high production rates, wells can pay out in four to six months. Some operators prefer the 1,280-acre spacing units over the 640-acre spacing units because of cost savings associated with the drilling of one well instead of two. Operators are fracture stimulating wells with 20-plus stages.

Various methods have been proposed to explore for the Bakken. The methods include exploring along the depositional or erosional edge (which is more susceptible to fracturing, and fracture spacing decreases as bed thickness decreases); exploring structural flexures and lineaments; looking for Prairie dissolution areas as they might be areas of more intense fracturing; looking for geothermal anomalies (intense hydrocarbon generation might cause more intense fracturing); looking for primary reservoirs (i.e., the Middle Bakken); and looking for fractured areas identified by well logs.

The latest cycle of exploration and development in the Williston Basin is the most significant to date. Production for the U.S. part of the Williston Basin has gone from 2.5 Mbbl/d of oil to more than to 1 MMbbl/d of oil.

Regional geology

The Williston Basin is a large, intracratonic sedimentary basin that occupies parts of North Dakota, Montana, South Dakota, Saskatchewan and Manitoba. The basin, however, probably originated as a craton-margin basin and evolved to an intracratonic basin during the Cordilleran orogen. Sedimentation occurred throughout much of the Phanerozoic, and the thickness of the stratigraphic section is about 16,000 ft (Figure 5). Many unconformities are described in the stratigraphic section, but rocks of all Phanerozoic time periods are represented by some deposits (figures 2 and 5). Paleozoic strata consist mainly of cyclic carbonate deposits; the Mesozoic and Cenozoic strata consist mainly of siliciclastics.

During the Late Devonian and Early Mississippian, the basin was an area of active subsidence in a broad shelf area that existed along the western margin of North America. The proto-Williston Basin was an extension of Canada's Devonian Elk Point Basin and was situated in tropical regions near the equator.

Source areas for clastics found in the Bakken and Three Forks might include the Cedar Creek High, Central Montana High, Black Hills Highland, Transcontinental Arch and Canadian Shield.

The depositional and/or erosional limits of the Three Forks Formation and subsequent deposits of the Bakken members are shown in Figure 6. The Three Forks has the largest areal extent. After a period of erosion and nondeposi-

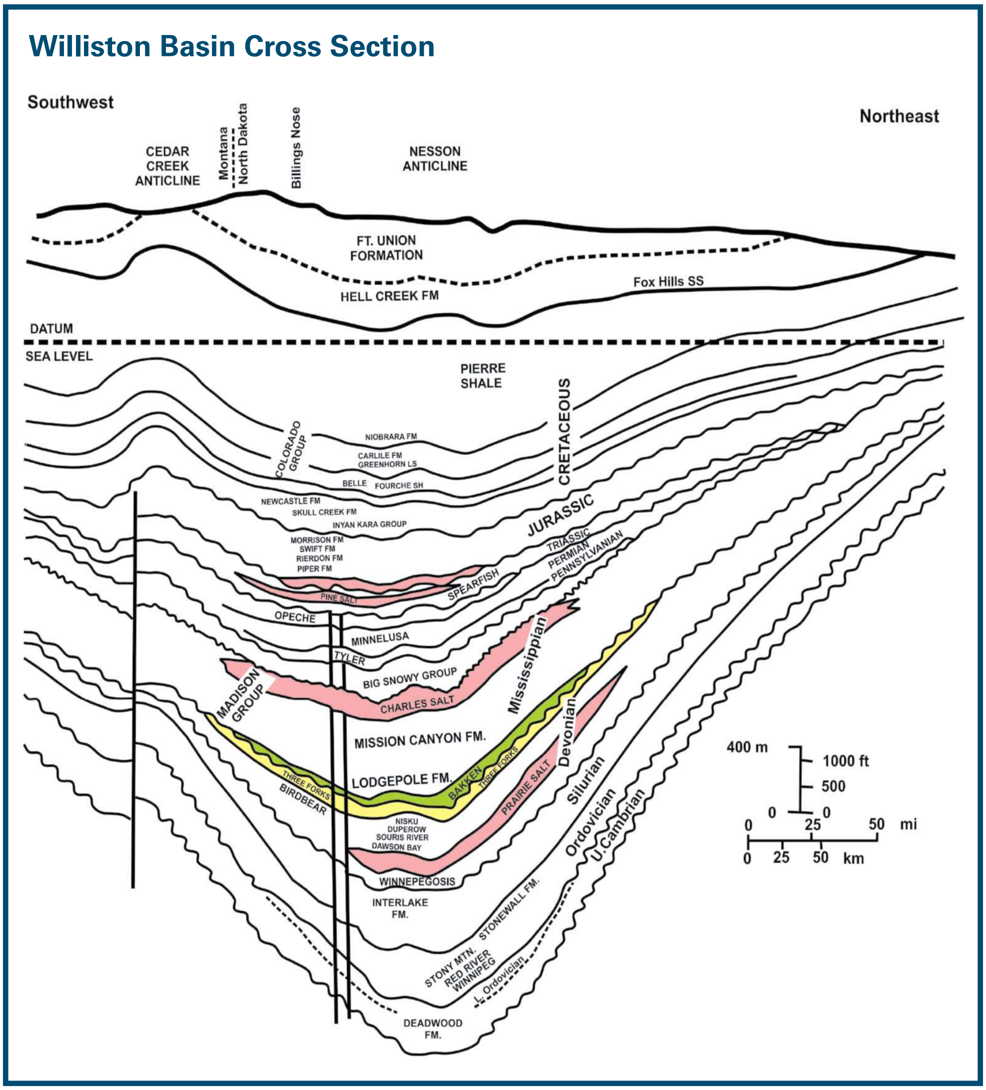


Figure 5. The generalized southwest-to-northeast cross section across the Williston Basin is shown. The Cedar Creek Anticline is a probable source of sediments for parts of the Bakken, Pronghorn and Three Forks intervals.

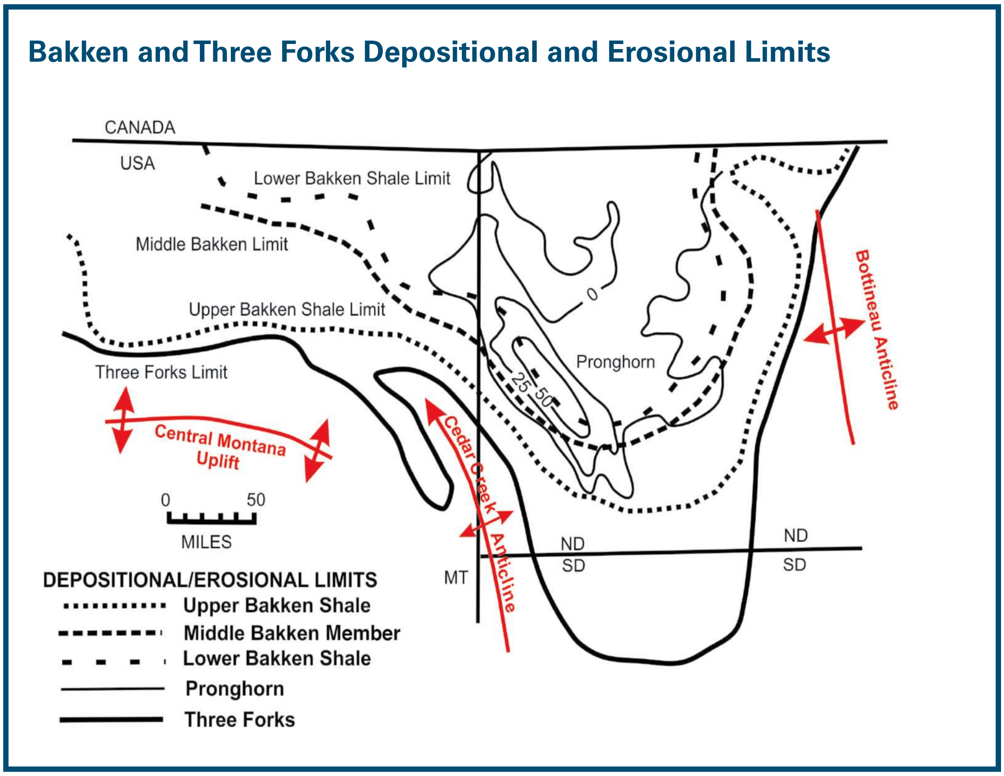


Figure 6. The depositional and erosional limits of the Bakken Formation members and the Three Forks Formation are shown.

tion, Pronghorn sediments filled in topographic lows. The Pronghorn has, unlike overlying Bakken strata, a depocenter at the southern margin of the basin with max thickness of 54 ft. The thickest Pronghorn accumulation extends in a linear trough shape, which coincides with both the edge of the Prairie salt and the Heart River fault on the southwestern side. The fault might have facilitated movement of fluids into the Prairie salt, which in turn could have triggered dissolution and larger scale salt collapse features.

After the major drop in sea level at the Three Forks-Bakken boundary, all four members of the Bakken exhibit a successively larger areal extent and onlapping relationships with the Three Forks at the basin margin, reflecting rising sea level conditions.

Three Precambrian provinces underlie the Williston Basin: the Superior Craton, Trans-Hudson orogenic belt and Wyoming Craton. These provinces trend north to south, and structures associated with them have strongly influenced later sedimentation and structural features. Notable structural features with a north grain in the Williston Basin include the Nesson, Billings, Little Knife and Tree Top anticlines. Northwest-trending prominent structural features include the Cedar Creek, Antelope and Poplar anticlines. Periodically, these structural features reactivated through time.

The Devonian Prairie evaporite occurs about 800 ft to 1,100 ft beneath the Bakken Formation (Figure 5). Regional and local dissolution is known to have occurred in the Prairie. Dissolution occurs both as a roughly linear front and also in isolated semicircular areas. Dissolution of the Devonian Prairie evaporite occurred at multiple times during the Paleozoic and Mesozoic. Isopach thicks in formations above Prairie thins help document the timing of dissolution. Models suggested for salt dissolution include: depositional facies control (dissolving fluids move through permeable beds adjacent to the salt horizon); compaction and dewatering of surrounding sediments (supplies the fluid necessary for salt dissolution); surface water recharge at the outcrop (resulting basinward flow dissolves salts); and direct or indirect result from minor tectonic movement related to Precambrian basement features (e.g. faults create pathways for fluids). Dissolution of the Prairie occurred during Bakken time and affected Bakken sediments. Thickening in the Middle Bakken at the Elm Coulee Field might be due to multistage salt dissolution.

Bakken Formation geology and production

The Bakken Formation regionally in the Williston Basin consists of four members: upper and lower organic-rich black shale, a middle member (silty dolostone or limestone to sandstone lithology) and a basal member recently named the Pronghorn (figures 3 and 7). The Bakken Formation ranges in thickness from a wedge edge to more than 140 ft (Figure 8) with the thickest area in the Bakken located in northwest North Dakota, east of the Nesson Anticline. The members of the Bakken thin and converge toward the margins of the Williston Basin and have an onlapping relationship with the underlying Three Forks. The contact between the Bakken and Three Forks is probably unconformable throughout much of the Williston Basin. The Bakken is sharply overlain by the Lodgepole. This sharp contact suggests a period of erosion or nondeposition prior to Lodgepole deposition. The lower, middle and upper members of the Bakken might represent two regressive-transgressive cycles of sedimentation. Following Three Forks deposition, major uplift and erosion occurred along the margins of the Williston Basin. This erosion resulted in deposition of the Pronghorn member of the Bakken. With a subsequent relative sea level rise and low-energy transgression, the Lower Bakken shales were deposited. Another regressive event resulted in the Middle Bakken being deposited, which was then followed by the next transgressive event, which deposits the Upper Bakken Shale.

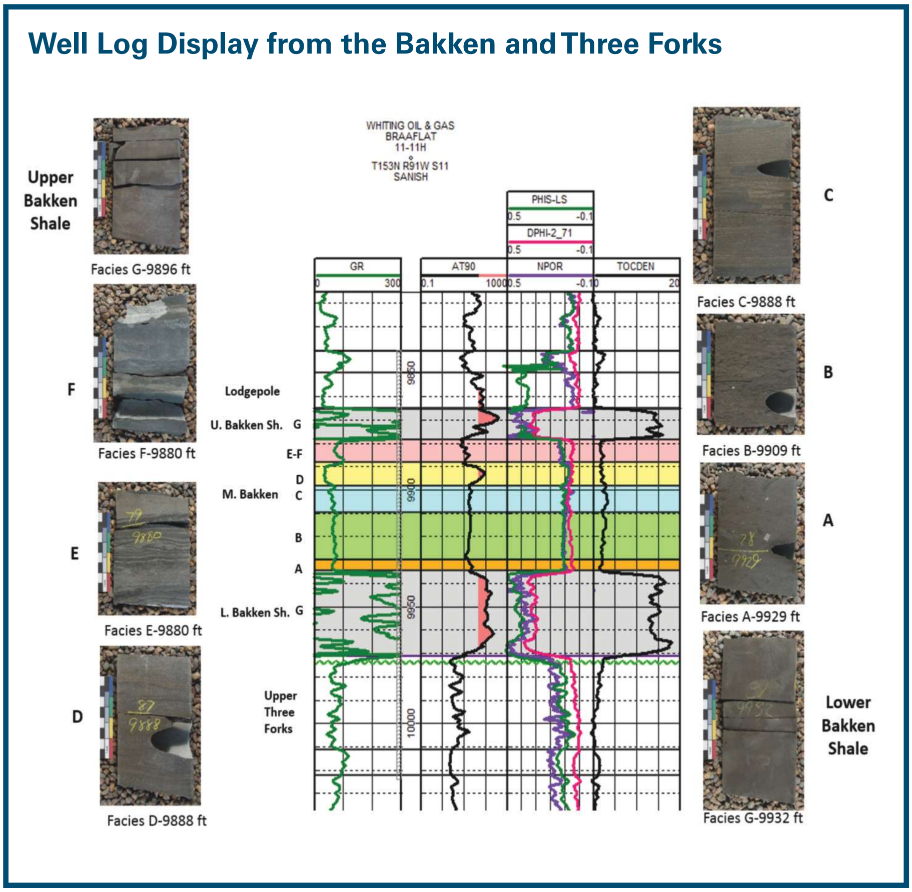


Figure 7. A well log display of the Bakken and Upper Three Forks from the Whiting Oil and Gas Braaflat 11-11H (sec. 11, T153N, R91W) is shown. Upper and Lower Bakken shales have very high gamma-ray readings (greater than 200°API). Middle Bakken and Three Forks have low porosities (less than 10%). Headings: GR –gamma ray; AT90 resistivity curves; PHIS-sonic porosity; DPHI-density porosity; NPOR-neutron porosity; TOCDEN-calculated TOC from density log. Resistivity greater than 50 ohm-m shaded pink.

The middle member of the Bakken was deposited in a shallow-water setting following a rapid sea level drop, resulting in a regressive event. In the central part of the basin, the middle member consists of argillaceous, greenish-gray, highly fossiliferous, pyritic siltstones, which indicate an environment that was moderately well oxygenated but occasionally suboxic. The upper parts of the middle member have cross-stratified sandy intervals, which suggest strong current action. The mineralogy of the Middle Bakken is variable across the basin and consists of 30% to 60% siliciclastic material (quartz and feldspar), 30% to 80% carbonate (calcite and dolomite) and minor matrix material (illite, smectite, chlorite and kaolinite). The sources of the detrital fraction in the Middle Bakken are thought to be from the north and northwest. The middle member ranges in thickness from a wedge edge to more than 70 ft (Figure 9). The thickest middle member occurs east of the Nesson Anticline. A thick also occurs in the general Elm Coulee area. Isolated thicks also occur along the east flank of the Williston, which might be due to Prairie salt dissolution.

The Middle Bakken can be subdivided into multiple facies (figures 3 and 7). All the facies are

Bakken Formation Isopach Map

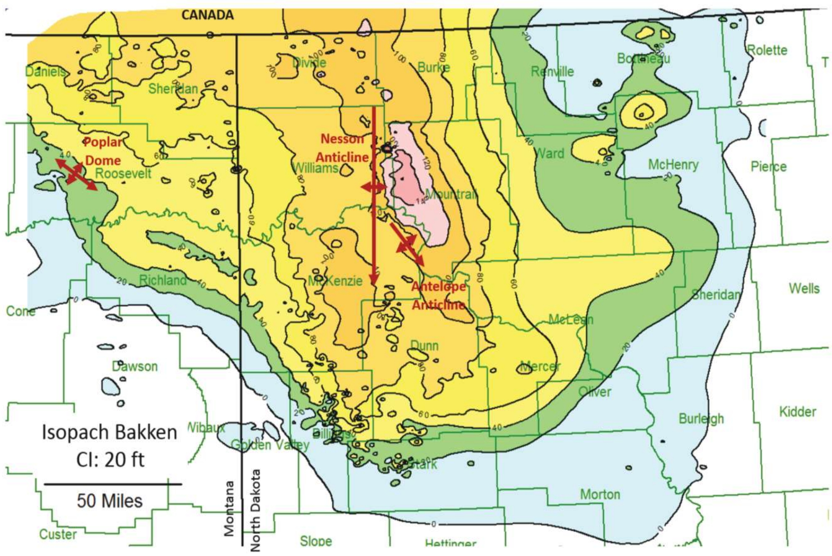


Figure 8. An isopach map of the Bakken Formation is shown. The Bakken ranges in thickness from a wedge edge to more than 140 ft. The thickest area is just east of the Nesson Anticline in Mountrail County, N.D.

Middle Bakken Shale Isopach Map

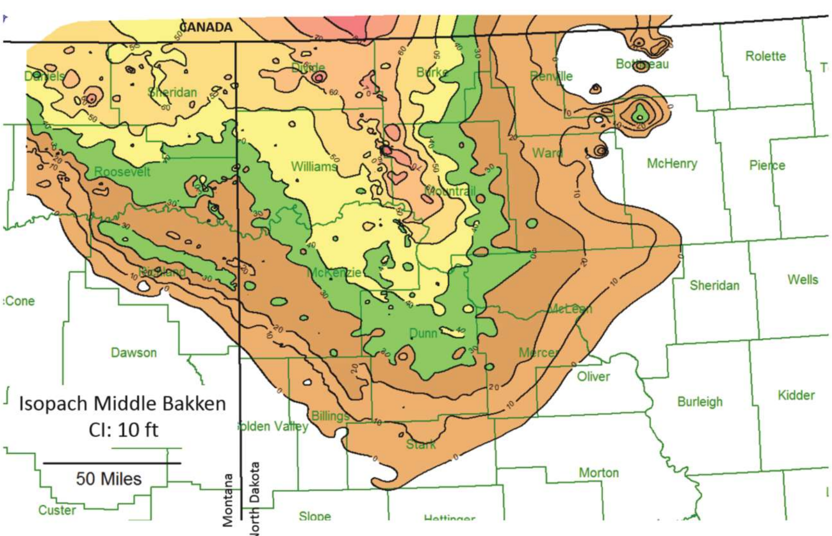


Figure 9. An isopach map of the Middle Bakken Shale is shown. The contour interval equals 10 ft. The Middle Bakken Shale ranges in thickness from a wedge edge to more than 70 ft.

thought to be related to deposition in a shallow-water shelf setting and appear to represent a shallowing upward sequence followed by a water-deepening event. The facies from bottom to top are Facies A, a fossiliferous calcareous siltstone; Facies B, bioturbated calcareous clay-rich siltstone to very fine-grained sandstone; Facies C, a thinly bedded to laminated calcareous very fine-grained sandstone; Facies D, the highest energy facies, which consists of alternating beds of fine-grained sandstone to carbonate grainstones (oolites and bioclastic debris); Facies E, which represents the start of the water deepening and consists of thinly bedded, occasionally microbial-laminated to parallel-laminated siltstone; and Facies F, which consists of fossiliferous dolomitic to calcitic siltstone. The facies are widespread across the Williston Basin with some exceptions. Laminites in Facies C were recently interpreted to be the result of tidal energies. Facies D is only locally developed; the amount of dolomite changes from area to area, and production is associated with matrix development in facies B, C, D and E and microfracturing. Facies B and C produce at Elm Coulee (Facies D is not present or very thin), whereas facies C, D and E produce in the Sanish-Parshall area. Typical facies found in the Sanish-Parshall area are shown in Figure 7. Mineralogy changes in the Middle Bakken across the Williston Basin.

A variety of geologic factors and technological factors influence Middle Bakken productivity. Technological factors include lateral length, number of hydraulic fracturing stages, proppant volume and type, proppant loading, fluid type used in hydraulic fracturing and volume, fluid/proppant ratio, injection rate, treatment pressure, choke sizes, well spacing, and plug-and-perf vs. sliding-sleeves completions. Geologic factors include reservoir quality (matrix porosity and permeability), reservoir thickness, oil and water saturations, hydrocarbon generation potential, source rock maturity, overpressure, structure and regional stress regime, natural fractures, mechanical stratigraphy, amount of migration and types of traps. Geologic factors such as oil and water saturations, source rock maturity, reservoir quality and thickness generally outweigh technological factors.

The first 90 days of production (oil/oil plus water) provide a useful indication of productivity and sweet spots (a technique that was developed by Cosima Theloy). Figure 10 illustrates areas that produce more oil than water based on this production. The areas of highest oil-to-water production are Elm Coulee, the Billings Nose area, the Parshall-Sanish area, the Nesson Anticline and the Antelope Anticline area.

EURs for the Middle Bakken are shown in figures 11 and 12. The best EURs for the Bakken are in the Sanish-Parshall area with 632 Mbbl of oil per well. The Fort Berthold area is second best with 569 Mbbl of oil per well. This is followed by the Bear Den area (536 Mbbl of oil per well) and South Nesson area (506 Mbbl of oil per well). Next is the Bailey area at 459 Mbbl of oil per well. The updip eastern margin of the Bakken production is in an area of overpressuring. The Nesson Anticline is also a high-EUR area, which relates to structural controls on productivity. The North Nesson area has EURs of 393 Mbbl of oil per well.

This area generally has good reservoir quality, and the cause of lower EURs adjacent to this area might be partial migration of hydrocarbons. Note the low EURs on the flanks of the Nesson Anticline in Figure 11, which also illustrates migration occurring in these areas. The poorest producing area is St. Demetrius at 209 Mbbl of oil per well.

Bakken Production for First 90 Days

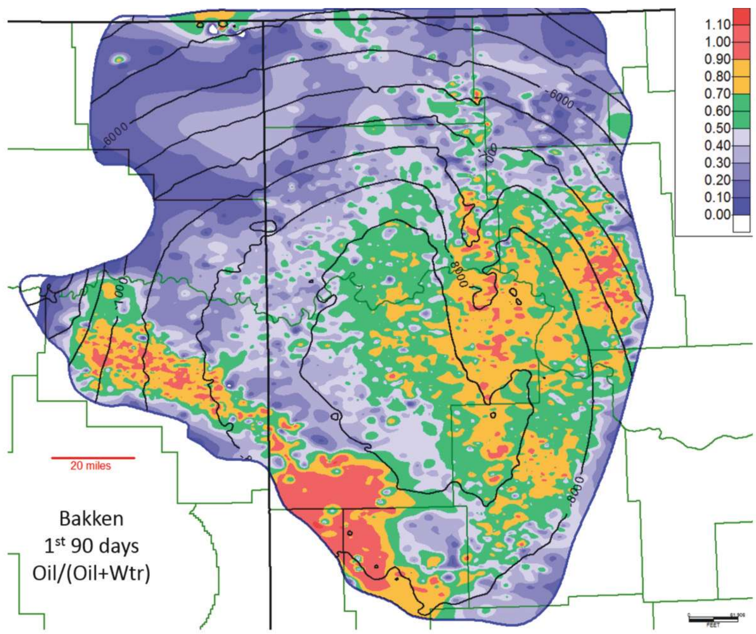


Figure 10. The Bakken's first 90 days of production of oil/oil plus water is shown. Sweet spot areas with low water production are the warmer colors.

Bakken EUR Map

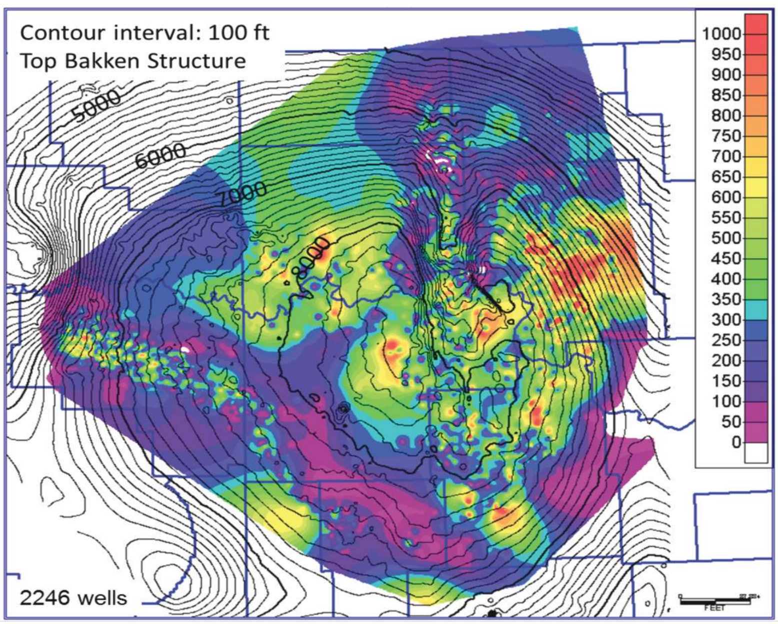


Figure 11. A Bakken EUR map is shown. Note the areas of low production along the flanks of the Nesson Anticline, which suggest migration out of these areas. *(Source: CSM PhD dissertation, Theloy, 2014)*

Average EUR from 2010 to 2011

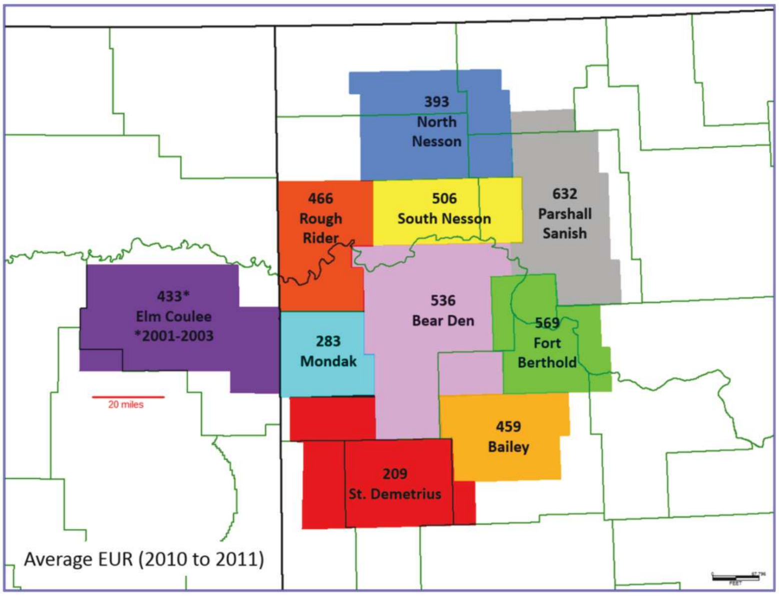


Figure 12. The average EUR from 2010 to 2011 by area (Mbbl) is shown. With the exception of Elm Coulee, the average EUR was calculated from wells drilled between 2010 and 2011. *(Source: CSM PhD dissertation, Theloy, 2014)*

Sweet Spots in the Bakken

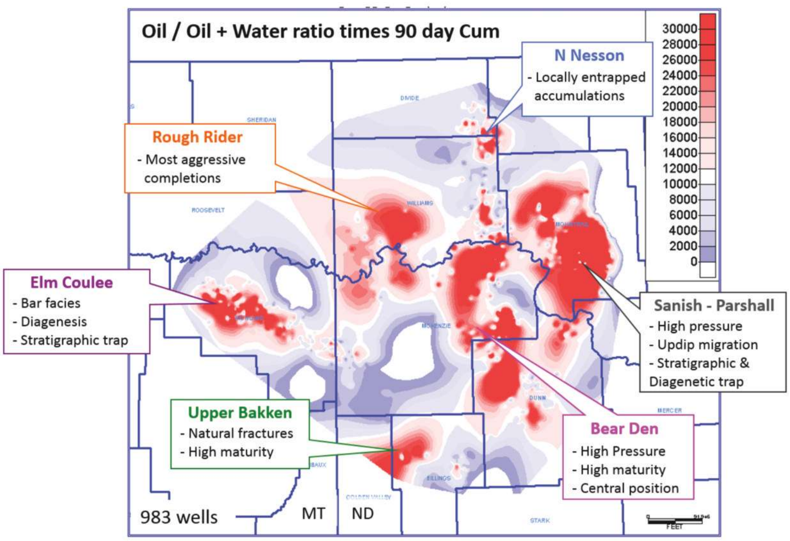


Figure 13. The Bakken-producing sweet spot areas are shown. The accumulation is a continuous accumulation, but individual sweet spot areas result from different causes. *(Source: CSM PhD dissertation, Theloy, 2014)*

Mondak is slightly better at 283 Mbbl of oil per well. These poorer areas are probably related to the thinness of the Bakken and poorer reservoir quality. Elm Coulee has an EUR per well of 433 Mbbl of oil. These EURs are from 2001 to 2003 when multistage fracture stimulation was not being performed.

Figure 13 summarizes the various Bakken producing areas and reasons production differs from area to area. In general, structure, stratigraphy and pore pressure are key ingredients to good production.

Pronghorn

The Pronghorn is the basal member of the Bakken Formation and unconformably overlies the Three Forks (Figure 3). The Pronghorn is subdivided into four lithofacies, which are from bottom to top: PH-1, a heavily bioturbated fine-grained sandstone; PH-2, a burrowed dolomitic silty mudstone with storm deposits; PH-3, a skeletal lime wackestone to packstone; and PH-4, a shale with siltstone and sandstone laminations. The Pronghorn shows an overall deepening and fining upward character.

The subtidal deposits of the Pronghorn unconformably overlie the Three Forks Formation, and usually a lag of rip-up clasts and abundant pyrite is developed in the basal portion. The contact between the Pronghorn and the Lower Bakken Shale is interpreted as transgressive surface of erosion marking the Pronghorn as lowstand deposits. A transgressive surface is recognized within the upper part of the Pronghorn, and it might be possible that more than one surface exists or that the vertical position of the surface varies depending on the location in the basin.

The Pronghorn ranges in thickness from a zero edge to more than 50 ft. Much of the burrowed dolomite part of the Pronghorn interval might be derived from the Cedar Creek Anticline area where the Three Forks and Pronghorn are absent due to erosional truncation.

Three Forks Formation

The name Three Forks Shale was first used for beds resting between the Jefferson Formation and Madison Limestone for outcrops near Three Forks, Mont. The name was later changed to Three Forks Formation.

The original Three Forks type section in the Williston Basin was named in the Mobil Producing Co. No. 1 Solomon Bird Bear well (sec. 22, T 149N, R 91W, Dunn County, N.D.). Poor preservation of the original type section core led to the selection of a new standard reference section for the Three Forks in the EOG Resources #2-11H Liberty well (sec. 11, T 151N, R 91W, Mountrail County, N.D.).

The Three Forks ranges in thickness from less than 25 ft to more than 250 ft in the mapped area (Figure 14). Thickness patterns are controlled by paleostructural features such as the Poplar Dome, Nesson, Antelope, Cedar Creek and Bottineau anticlines. Thinning and/or truncation occurs over the crest of the highs, and thickening of strata occurs on the flanks of the highs.

Many subdivisions have been proposed for the Three Forks. For the sake of simplicity, the interval will be subdivided into three units in this paper, including upper, middle and lower. These subdivisions are illustrated in Figure 15. The extent of each unit decreases upward, with the Lower Three Forks showing the largest areal distribution and the Upper Three Forks showing the smallest areal distribution. This in part is due to the unconformity at the top of the Three Forks.

The Three Forks is an argillaceous, silty to very fine-grained dolostone throughout. The formation becomes anhydritic toward the base. The hematite content increases in the Middle and Lower Three Forks, whereas the pyrite content increases in the Upper Three Forks. Small amounts of halite also show up in an X-ray diffraction analysis of the formation, showing the high salinity of the formation. Often times, halite crystals will precipitate on

Three Forks Isopach Map

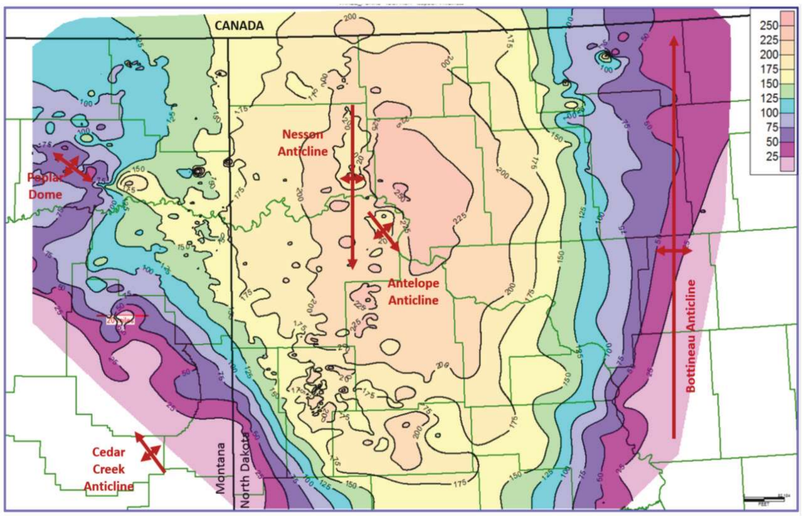


Figure 14. An isopach map of the total Three Forks interval is shown. Structural features control the thickness patterns seen on this map. The thickest Three Forks area is east of the Nesson Anticline.

Well Log Display from the Bakken and Three Forks

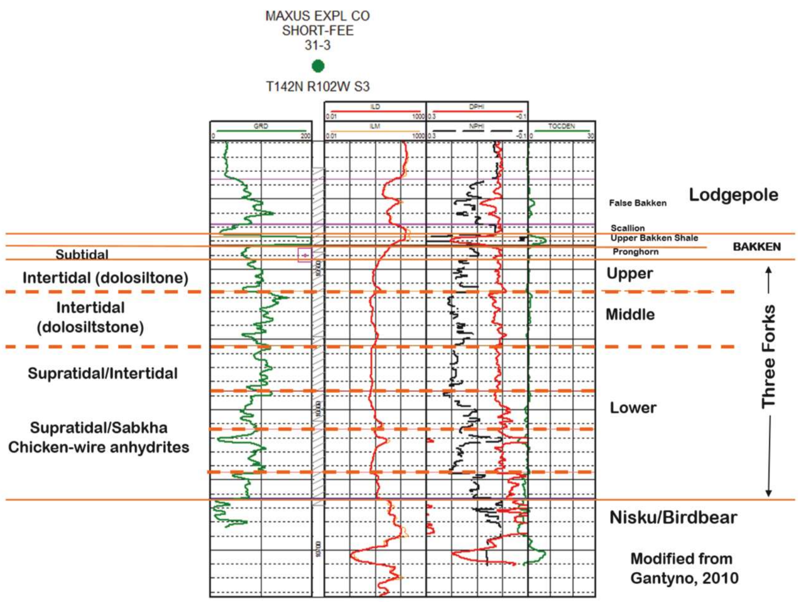


Figure 15. A well log display of the Bakken and Three Forks from the Maxus Short-Fee 31-3 (sec. 3, T142N, R102W) is shown. Headings: GRD—gamma ray; ILD and ILM resistivity curves; NPHI—porosity; DPHI—density porosity; and TOCDEN—calculated TOC from density log.

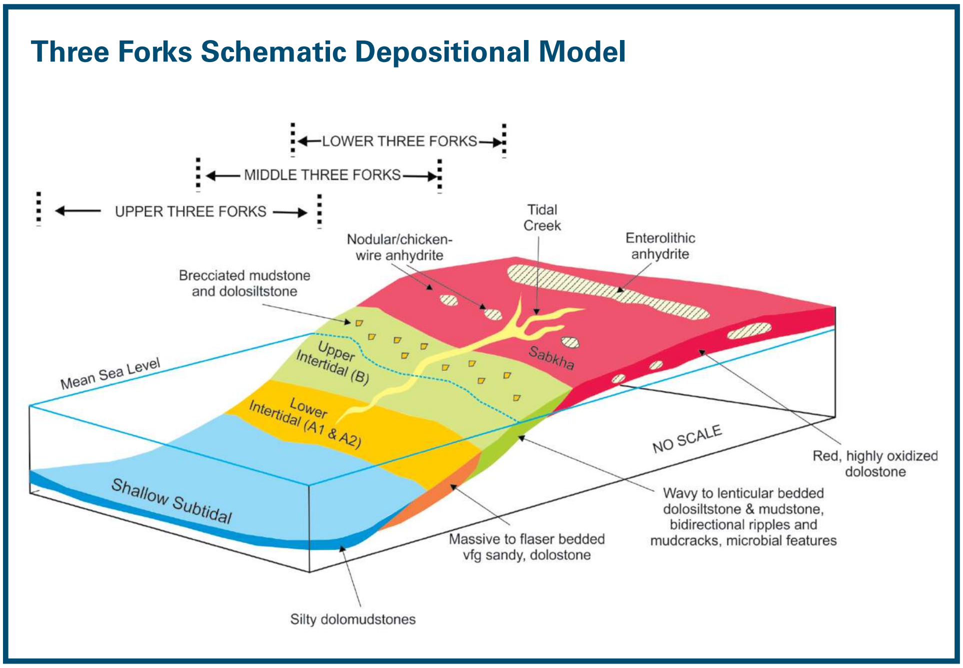


Figure 16. A Three Forks schematic depositional model is illustrated. The approximate settings for the Lower, Middle and Upper Three Forks are shown. Anhydrites are mainly found in the Lower Three Forks.

slabbed core surfaces (post slabbing). Halite beds are not reported to occur in the Three Forks, which might be a result of local dissolution. Salt hoppers are present in outcrops in central Montana.

The Lower and Middle Three Forks sections are known for their red color caused by the presence of hematite. The hematite occurs as a thin coating around grains. The source of the hematite, as in most red-bed sequences, is probably diagenetic. The source of hematite is generally from intrastratal dissolution of detrital silicates such as hornblende, augite, olivine, chlorite, biotite and magnetite. The Three Forks Formation has a large percentage of chlorite in its composition. The source of the chlorite is unknown but might be from volcanic arcs to the west. The red color comes from the oxidizing diagenetic environment. Only a small amount of iron, 0.1%, is sufficient to impart a red color. If reducing conditions prevail, the iron will be in a ferrous state and impart a green color. Secondary alteration of the red color takes place when reducing solutions penetrate into red sediments. This commonly occurs along porous beds and fractures. The Upper Three Forks has a distinct green color in mudrock intervals, which might be an alteration of a previous red color.

Most of the previous workers in the Three Forks have interpreted the depositional environment to be subtidal to supratidal (Figure 16). Overall, the Three Forks represents a water-deepening cycle with more coastal and inland sabkha deposits in the Lower Three Forks and intertidal deposits in the Middle and Upper Three Forks.

Lower Three Forks

The deposits of the Lower Three Forks reflect mainly a low-energy, supratidal sabkha setting in dry, evaporative climate conditions. The very fine-grained sizes of sediments and the abundance of anhydrite set the Lower Three Forks deposits apart from the overlying units. Anhydrite occurs as massive, argillaceous mosaic anhydrite or as distinctive beds, stringers and nodules within a mudstone matrix. The precipitation of anhydrite is interpreted to have occurred coevally with sedimentation or at a very early stage of diagenesis. The dolomitic claystones within the Lower Three Forks are either reddish-brown or green in color, and both variations can occur in close juxtaposition to each other. The dolomudstones contain minor amounts of silt and are typically noncalcareous, hard, fissile and well-cemented. Usually, the mudstones are structureless to faintly laminated. Other sedimentary structures include compaction-loading features, dewatering structures, distortion around anhydrite nodules and granule-sized clasts, as well as mud cracks, syneresis cracks and brecciation. The breccias contain clay and dolomudstone fragments, floating in a matrix-supported fabric. Common cementing agents are anhydrite, dolomite and pyrite in disseminated form.

Middle Three Forks

The Middle Three Forks ranges in thickness from 20 ft to 60 ft across the mapped area. Thinning occurs toward the flanks of the Williston Basin.

The Middle Three Forks consists of beds of anhydritic, calcareous, argillaceous dolostone, silty dolostone and sandy argillaceous dolostone. Generally, the unit is very fine-grained, and grain size decreases upward. The unit is similar to the Upper Three Forks with an overall shallowing upward sequence followed by a water-deepening event (dolomudstone).

The Middle Three Forks is dominated by chaotic and brecciated facies. Two types of brecciated facies occur in the Middle Three Forks, including matrix-supported and clast-supported breccia. The abundance of mud-supported breccia might be due to storm events. Original sedimentary structures, such as parallel and ripple laminations, are rarely preserved due to the high degree of brecciation and soft-sediment deformation (including dewatering structures).

A laminated facies often occurs near the base of the Middle Three Forks. This facies consists of thin- to thick-bedded (millimeter to centimeter scale) alternating layers of mudstones and dolomitic siltstones.

The top of the Middle Three Forks is a massive (possibly burrowed), structureless, subtidal mudstone. This unit is referred to as the RT marker bed and is 2 ft to 20 ft thick. The unit is dominated by clay-sized material with silt-sized quartz and dolomite. The average composition of this upper unit is 38% dolomite, 30% clay, 27% quartz and 2% pyrite.

Upper Three Forks

The Upper Three Forks is dominated by silt-sized and some very fine-grained sandstones and dolomite and has low permeabilities and porosities. The Upper Three Forks ranges in thickness from a wedge edge to more than 40 ft in areas east of the Nesson Anticline (Figure 17). The unit thins toward the margins of the depositional basin because of erosional truncation. The unit is diffi-

Upper Three Forks Isopach Map

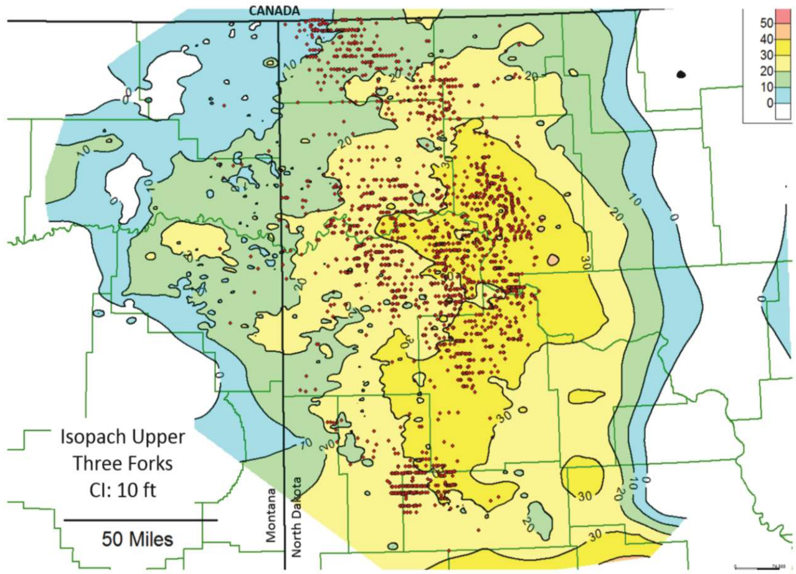


Figure 17. An isopach map of the Upper Three Forks is shown. Thinning occurs toward Poplar Dome and the Cedar Creek Anticline. The vast majority of Three Forks wells are drilled in this interval. The red dots indicate Three Forks producers.

Upper Three Forks Schematic

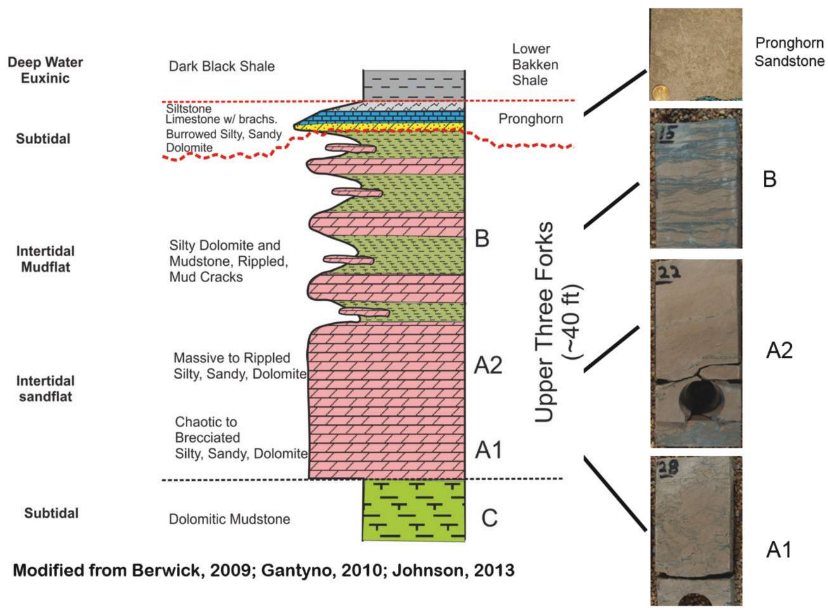


Figure 18. A schematic of the Upper Three Forks shows facies, core photographs and interpreted depositional environment. Tidal environments dominate the Upper Three Forks.

Three Forks Production for First 90 Days

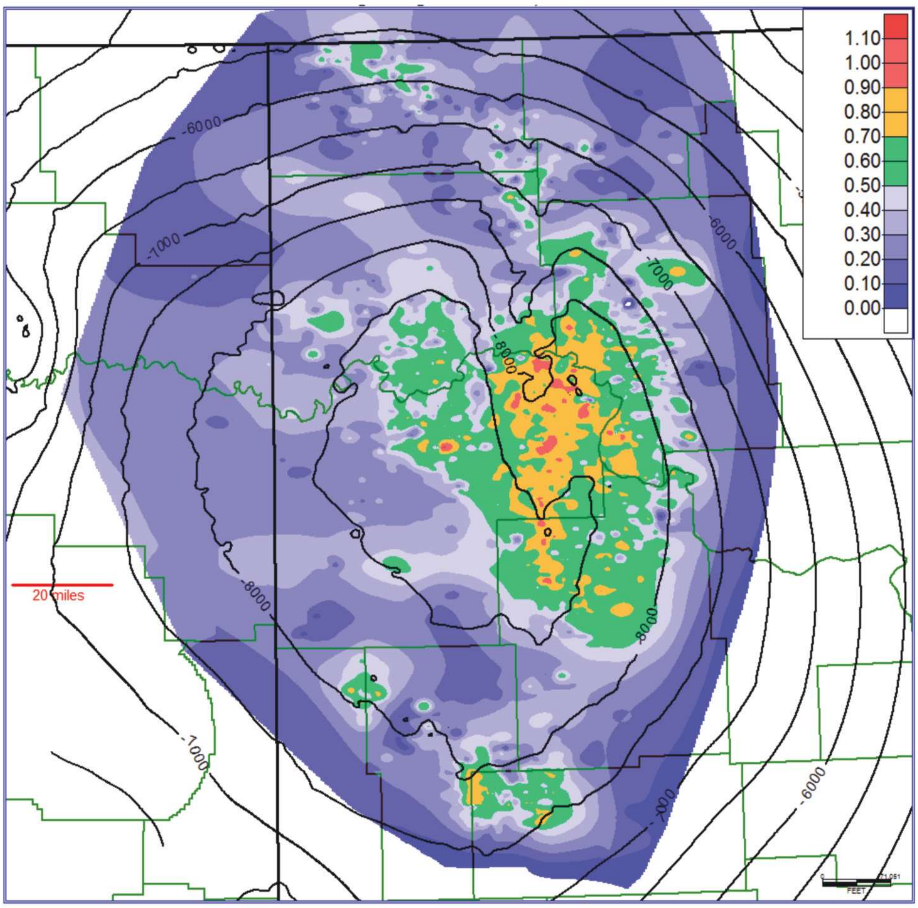


Figure 19. A Three Forks production map for the first 90 days of oil/oil plus water is shown. The warm colors (green to red) indicate wells that produce more oil than water. The cool colors (blue) indicate wells that produce more water than oil.

cult to separate from the overlying Pronghorn when looking at logs.

The Upper Three Forks is evolving into a significant resource play in the Williston Basin. To date, more than 2,880 wells (including the older wells at Antelope) have been completed in the Upper Three Forks (Figure 17). The Upper Three Forks consists largely of pinkish-tan silty dolostones, which are interbedded with green chloritic, dolomitic mudstone (Figure 18). A variety of facies have been reported in the Upper Three Forks that range in depositional environment from subtidal to supratidal (Figure 16). Typical sedimentary structures include parallel to subparallel laminations, uni- and bidirectional ripple cross-laminations, mud cracks, syneresis cracks and soft sediment deformation. Deposition is a shallowing upward succession ranging from subtidal to upper intertidal. The Pronghorn member of the Bakken sits unconformably on the Three Forks.

The facies in the Upper Three Forks is shown by Figure 18. The basal Upper Three Forks (A1 and A2) is a sandy to silty dolostone unit that overlies the green mudstone facies of the Middle Three Forks. The unit ranges in thickness from 10 ft to 25 ft. The mineralogic composition of the basal Upper Three Forks is 57% dolomite, 29% quartz, 10% clay and 2% pyrite. The unit can be subdivided into two subfacies, A1 and A2. The lower A1 facies is mottled, possibly burrowed, and is characterized by soft sediment deformation, which resembles dewatering structures. Upward-directed dewatering features are present. The overlying A2 facies is laminated to massive, silty dolostone. Some ripple and wavy laminations are present in the unit. The A1 and A2 facies are interpreted as shallowing upward succession. Facies B, shown in Figure 18, consists of interlaminated to interbedded green dolomitic mudstone and pinkish-tan silty dolostones. The green mudstones constitute 30% to 70% of the unit. Sedimentary structures are uni- and bidirectional ripple cross-laminations, double clay drapes, mud cracks, syneresis cracks, scour surfaces, soft sediment deformation and rare intraclast conglomerates. The intraclast conglomerates might form in small tidal channels, by storm events or evaporite dissolution.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Three Forks production

The original discovery at the Antelope Field in 1953 early on established the Upper Three Forks as a viable reservoir in the Williston Basin. The Upper Three Forks remained fairly dormant until recently drilled horizontal wells again have indicated its large potential.

The North Dakota Industrial Commision has recently estimated that the Three Forks will have recoverable reserves of 1.9 Bbbl of oil across much of the Williston Basin. The Three Forks play coincides with the Bakken play, which adds significantly to the reserves across the basin. The 2013 mean for technologically recoverable resource estimates for the Three Forks was 3.371 Bbbl of oil, 3.5 Tcf of gas and 281 MMbbl of NGL, according to the USGS.

The current cumulative total is about 263.4 MMbbl of oil and 294.7 MMcf of gas. Figure 19 illustrates the first 90 days of production (oil/oil plus water) for the Three Forks and low-water producing areas. The southern Nesson Anticline and areas east of the Nesson Anticline show the highest oil-to-water ratio.

Reservoir properties of the Bakken and Three Forks

Measured core porosity and permeability are very low in the Bakken, Sanish and Three Forks reservoirs (less than 10% porosity and less than 0.1 mD permeability) in the Williston Basin, so productivity is assumed to be due to natural and artificial fracturing. The reservoirs generally require advanced technology to get them to produce (fracture stimulation and horizontal stimulation). For this reason, they should be considered to be technology reservoirs. Natural fractures in some areas (e.g., the Billings Nose area and Antelope Field) are sufficient for vertical well production.

A core analysis from the Whiting Braaflat 11-11H (sec. 11, T153N, R91W) provides the following information. The Scallion member of the Lodgepole has an average porosity of 2.3% and average permeability of 0.12 mD (most permeability plugs had visible fractures). Average grain density is 2.7. The Middle Bakken has average porosity of 6.7% and average permeability of 0.33 mD (including plugs with visible fractures). Excluding core plugs with fractures, the average permeability number drops to 0.028 mD. Average grain density in the Middle Bakken is 2.7. The Three Forks has an average porosity of 7.6% and average permeability of 1.1 mD (including core plugs with visible fractures). The average permeability, excluding the plugs with fractures, is 0.23 mD. Average grain density in the Three Forks is 2.8. Most of the visible fractures in the core are horizontal. The Braaflat 11-11H (Figure 7) was completed as a horizontal well in the Middle Bakken for about 2.7 Mbbl/d of oil and about 2 Mcf/d. The well has a cumulative production of 359 Mbbl of oil and 232 MMcf of gas.

Measured core porosity and permeability also are very low in the Bakken Shale, Pronghorn (formerly known as the Sanish) and Three Forks reservoirs at the Antelope Field. Core analysis from the Duncan Rose #1 (sec. 33, T15N, R94W) provides the following information. The Lower Bakken Shale has porosities of 3.8% and permeabilities of 0.01 mD. The Pronghorn has porosities ranging from 6% to 9% and permeabilities ranging from 0.08 mD to 0.33 mD. The Upper Three Forks has porosities ranging from 8.3% to 10.6% and permeabilities ranging from 0.01 mD to 0.18 mD. One foot of Three Forks 10609-10 reported a permeability of 6.88 mD, but this is interpreted to be due to a horizontal fracture.

Lower and Upper Bakken shales

The upper and lower shale members are potential source rocks and are lithologically similar throughout much of the basin. The shales are regarded as dominantly Type II kerogen. The shales are potential source beds for the Bakken, Three Forks and Lodgepole formations. The shales are dark-gray to black, hard, siliceous, slightly calcareous, dolomitic, pyritic, massive to fissile and generally either break along horizontal fractures or with conchoidal fractures. Detrital silt grains are disseminated throughout the shale interval as scattered grains. Some discontinuous laminate of silt grains is present. The silt-sized material is probably eolian in origin. The shales contain radiolaria, conodonts, ostracodes, small cephalopods, small brachiopods and *Tasmanites* (algae) fossils. The shales lack bioturbation but do contain flattened fecal pellets and lack evidence of bottom-current transport except in the transi-

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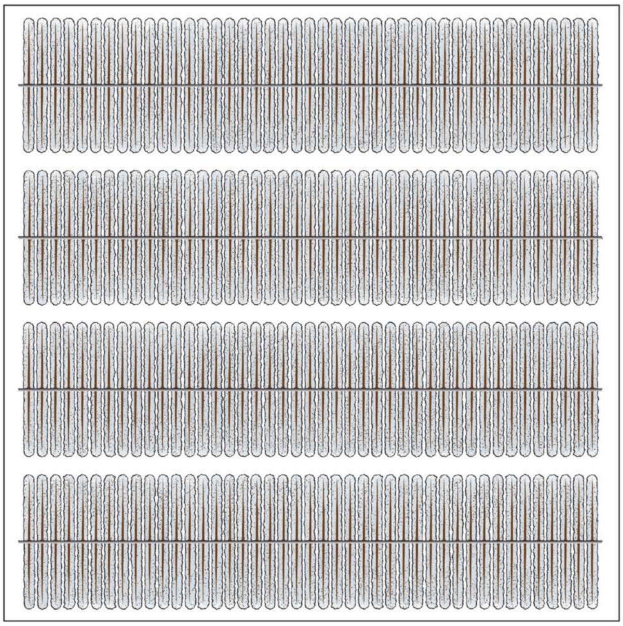

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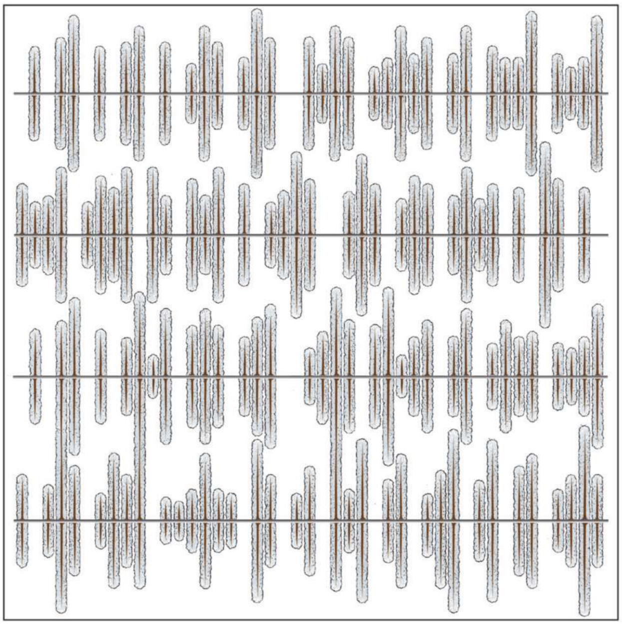

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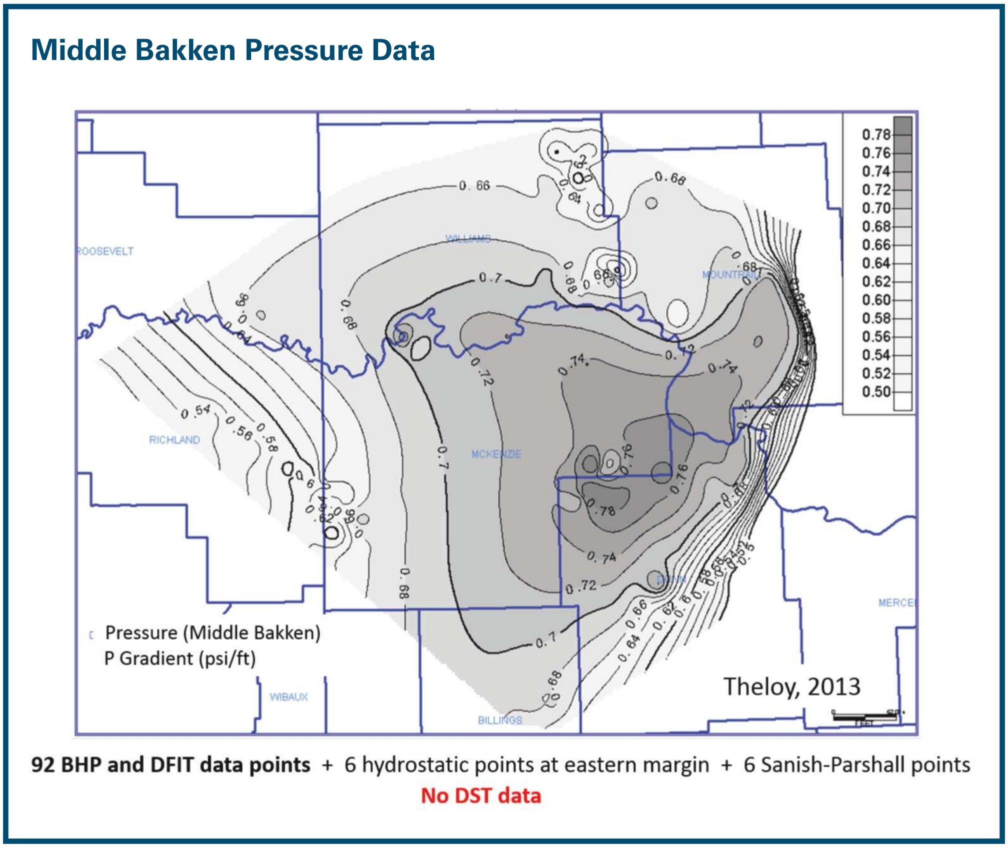


Figure 20. Pressure data for the Middle Bakken reservoir are shown. Data are from 92 bottomhole pressure and diagnostic fracture injection test datapoints plus six hydrostatic points at the eastern margin plus six Sanish-Parshall points. *(Source: CSM PhD dissertation, Theloy, 2014)*

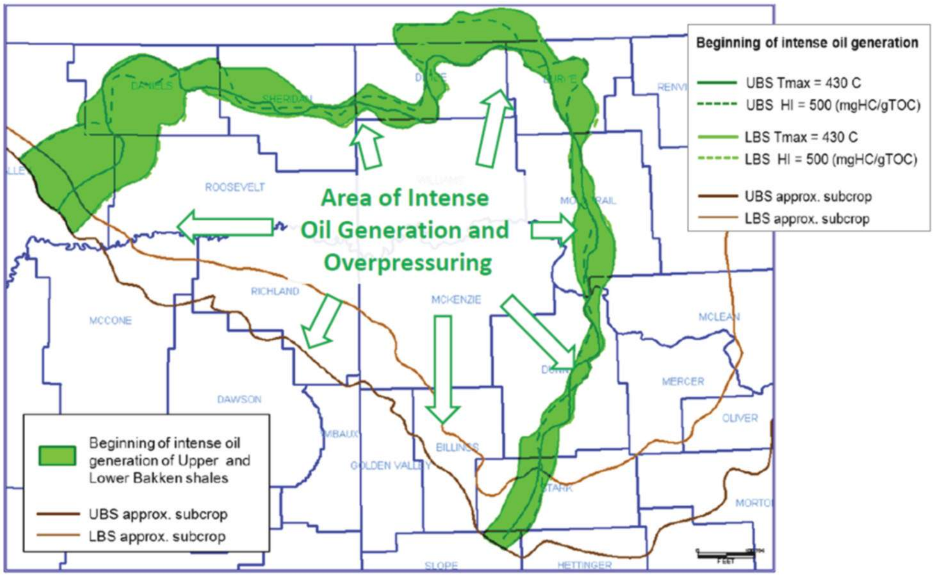
tional 1 ft to 3 ft at the base and tops of the shales. The shales are dissimilar in that the upper shale lacks limestone and greenish-gray shale beds found locally in the lower shale. The Lower Bakken Shale has a greater abundance of *Tasmanites*. Secondary pyrite occurs disseminated throughout the shale interval and as individual laminations and lenses. The shales consist of dark organic material, clay, silt-sized quartz, and some calcite and dolomite (both detrital and authigenic). The shale is kerogen rich in the deeper parts of the basin, and the organic material is distributed throughout. The Bakken kerogen is an amorphous kerogen inferred to be sapropelic, and the composition consists of 70% to 95% amorphous material, 0% to 20% herbaceous material, up to 30% coaly material (recycled opaque material) and 5% woody material. The amorphous material probably has an algal origin because of the high hydrocarbon-generating capacity of the material determined from pyrolysis (greater than 500 mg HC/g OC at shallow depths). The total organic carbon (TOC) content of the Bakken shales averages 11.3 weight percentage (wt.%) in thermally mature areas of the basin. The shales average 15 wt.% to 20 wt.% TOC where thermally immature.

An equation to calculate TOC content using bulk density logs is as follows: TOC = $(154{,}497/\rho) - 57.261$, where ρ is the bulk density of the shale. Figure 7 illustrates the calculated TOC for the Braaflat 11-11H (sec. 11, T153N, R91W) from the Sanish Field. The calculated TOC is comparable to the actual measured TOC of 10 wt.% to 18 wt.%.

The upper and lower shale are interpreted to have been deposited in an offshore marine anoxic or oxygen-restricted environment during periods of sea level rise. The anoxic conditions might have resulted from a stratified hydrologic regime. The stratified water column is envisioned as having an upper water layer that is well oxygenated and nutrient rich. High organic production occurred in this layer (probably planktonic algae). With the death of the organisms, they sank through stagnant bottom waters and were deposited. Anoxic conditions are created by restricted circulation and in part by destruction of organic matter by consuming organisms that remove oxygen and release hydrogen sulfide. Anoxic conditions are indicated by the lack of benthic fauna and burrowing and by high TOC content. The Bakken might be part of a continent-wide anoxic event that took place from the Late Famennian through Kinderhookian time. The Bakken is correlative with the Woodford-Percha-Leatham-Sappington-Exshaw-Cottonwood Canyon source rock facies of the western Cordilleran and southern craton-margin geosynclines and the Antrim-Sunbury-New Albany-Chattanooga and equivalent source rock facies of the Appalachian geosyncline.

The Bakken is not thermally mature throughout the Williston Basin. The shales are thermally immature in the eastern part of the basin and characterized on well logs by low resistivity (i.e., water-wet). In the western Williston, the shales are characterized by high resistivity and are thought to be oil-wet. Hydrocarbons are nonconductive, which results in the extremely high resistivities. Further evidence of the presence of hydrocarbon saturation comes from core analyses and also plots of pyrolysis data (i.e., production index vs. depth plots or pyrolysis S1 vs. depth plots) with depth. These data clearly indicate that the Bakken shales are oil-saturated where they have high resistivity. Wettability tests in the Bakken illustrate that the upper and lower shales are oil-wet while the Lodgepole, Middle Bakken and Three Forks intervals are water-wet. The extremely high oil-to-water ratios associated with Bakken production suggest that most of the water has been displaced by the hydrocarbon generation. The ratios are 200:800:1 with the mean being 300:1. The small amount of coproduced water might be dissolved in Bakken oil and exsolves during production or it can be produced from the matrix of the reservoir rocks.

Area of Oil Generation and Overpressuring in the Bakken



Beginning of intense oil generation based on Tmax and HI constraints of both Upper and Lower Bakken shales

Figure 21. An area of intense oil generation and overpressuring based on Tmax and hydrogen index data is shown. Subcrops of the Upper and Lower Bakken shales also are shown. *(Source: CSM PhD dissertation, Theloy, 2014)*

Organic maturity recently has been modeled using the time-temperature index method. The models suggest that organic maturity started about 100 million years ago.

Most of the oil generated in the Bakken black shales might have been expelled into the middle member of the Bakken or the Upper Three Forks. Most of the oil generated in the Bakken stayed in the Bakken and did not migrate into the overlying Madison group.

The Lower Bakken Shale ranges in thickness from 0 ft to more than 50 ft. The thickest area is a north-south trending area just east of the Nesson Anticline. Slightly updip from the axis of the thick lies the greater Sanish-Parshall-Fort Berthold producing area. The Lower Bakken Shale is the main source bed for this sweet spot production area.

The Upper Bakken Shale also is an important source rock in the Bakken Petroleum System. The Upper Bakken Shale ranges in thickness from 0 ft to about 25 ft in the mapped area. No obvious structural controls on thickness variations are suggested other than a Prairie salt dissolution related thick shown in the southern part of the mapped area in Stark County, Ohio. This anomalous area is also the area of prolific Lodgepole mounds.

Bakken and Three Forks oils

The oil produced from the Bakken and Three Forks reservoirs is different from oils produced from Madison reservoirs. Bakken reservoir oils and Madison reservoir oils are different based on a number of factors including biomarker geochemistry. The Bakken reservoir oils have high diasterane/sterane values, indicating argillaceous source rocks; whereas, the Madison reservoir oils have low pristine/phytane and diasterane/sterane values and high norhopane/hopane values, indicating sourcing from carbonate rocks.

Bakken oils are moderate to high-gravity (26°API to 46°API), have low sulfur contents (less than 0.35 wt.%) and low pour points (average -25 F). Madison oils have higher sulfur contents (0.2 wt.% to more than 3.6 wt.%) and higher pour points (average 38 F).

Reservoir pressure

Reservoir pressure in the Bakken is regarded as overpressured with pressure gradients exceeding 0.5 psi/ft (Figure 20). The map is based on 92 bottomhole pressure and diagnostic fracture injection test datapoints, including six additional hydrostatic points at the eastern margin as well as six datapoints for the Sanish-Parshall area. High overpressures are found in large parts of the central basin and the Parshall area in the east, where gradients exceed 0.7 psi/ft. Elm Coulee has a pressure gradient of about 0.55 psi/ft. Parshall is reported to have a gradient of 0.74 psi/ft. The area west of the Nesson Anticline has pressure gradients of 0.6 psi/ft to 0.7 psi/ft. Pressure gradients in Montana are generally in the 0.5-plus psi/ft range.

The abnormal pressures in the Bakken and Three Forks suggest that the oil generated in the Bakken Petroleum System has largely stayed in the Bakken Petroleum System. Lower pressures indicate either pressure leak-off or areas where migration has taken place.

A summary diagram illustrating areas of thermal maturity and overpressuring in the Bakken Petroleum System is shown in Figure 21.

Fractures

Fractures enhance the reservoir quality of the tight Bakken reservoir. Three types of fractures are reported to occur in the Bakken: structural-related tectonic fractures, stress-related regional fractures and diagenetic fractures associated with overpressuring due to hydrocarbon generation. The best production in the Bakken-Three Forks comes from hydrocarbon-generated, related pervasive microfracturing combined with larger-scale fracturing (i.e., structural-related or stress-related regional fractures).

Fracturing of source rocks has been frequently discussed as a mechanism that enhances primary migration and increases permeability. Fracturing observed in source rocks is commonly horizontal; however, oblique fractures and fractures perpendicular to bedding planes also occur.

Summary

The Bakken and Three Forks are important tight oil resource plays. The production in the Williston Basin is increasing dramatically because of the excellent results in recent drilling. The amount of technically recoverable oil has recently been estimated by the USGS to be 7.3 Bbbl (including 3.7 Bbbl from the Three Forks and 3.6 Bbbl from the Bakken) in 2013. New technology and enhanced recoveries might add to the number in the future. Total Bakken and Three Forks production through December 2014 is about 1.3 Bbbl and 1.3 Tcf of gas from 12,051 wells (Figure 3). Thus, the play is in its early stages. Production from both the Three Forks and Bakken is excellent. Both fracture and matrix permeability are important in the play.

Fracturing in the Bakken Petroleum System occurs due to a variety of causes, including pore pressure; regional stress field; local structures (including salt dissolution features); and recurrent movement on basement fault systems. The regional stress field appears to play a significant role in how operators are orienting their laterals and overall production.

Many of the reservoirs in the Bakken Petroleum System have low permeability. Productive areas or sweet spots are localized areas of improved reservoir permeability through natural fracturing or development of matrix permeability, or a combination of both. Reservoir facies with matrix permeability are key ingredients to sweet spot areas. ■

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By Stephen A. Sonnenberg
Colorado School of Mines

The Niobrara is a significant, self-sourced resource play throughout the Rocky Mountain region. The combined technologies of horizontal drilling and multistage, hydraulic-fracture stimulation are unlocking reserves that previously were unobtainable.

Known production comes from both fracture and matrix porosity systems (dual porosity). High matrix porosity is present in the shallow biogenic gas accumulations of eastern Colorado and Western Kansas. The shallow biogenic play is important for natural gas production at burial depths of less than 3,500 ft. The deeper Niobrara thermogenic accumulations generally occur at burial depths greater than 7,000 ft. Burial diagenesis (chemical and mechanical compaction and cementation) reduces porosities to values less than 10% in the deeper parts of the various basins where the Niobrara is prospective. Mature Niobrara source rocks also are located in these areas of low porosity. Natural fractures can be important contributors to production in the deeper areas.

The Niobrara Petroleum System contains all the aspects of a large resource play (e.g., widespread mature source and reservoir rocks, and self-sourced). The Niobrara was deposited in the Western Interior Cretaceous (WIC) Basin and is a widespread unit in the Rocky Mountain region (figures 1 and 2). The WIC Basin was broken into numerous smaller basins during the Laramide orogeny (Late Cretaceous to Eocene). The Niobrara contains reservoir rocks, rich source beds and abundant seals (thus, self-sourced and sealed). The various productive lithologies all have low porosity and permeability. Total organic carbon (TOC) values in shales range from 2% to 8% in the eastern WIC area and are reduced to 1% to 3% because of siliciclastic dilution in the western WIC area. Laramide structural events exert the primary control on fracturing within the Niobrara as well as thermal maturity. Neogene extension fracturing is also thought to be an important component for locating production sweet spots. Understanding the thermal maturity of the source rocks will assist in predicting the distribution of hydrocarbon accumulations. Hydrocarbon generation might enhance the tectonic fractures and might also create new ones as a result of overpressuring associated with this process.

The Niobrara Petroleum System is thought to have created a continuous-type of accumulation in the deeper parts of many basins in the Rocky Mountain region. A continuous accumulation is a hydrocarbon accumulation that has some or all of the following characteristics: pervasive hydrocarbon charge throughout a large area; no well-defined, oil- or gas-water contact; diffuse boundaries; commonly is abnormally pressured; large in-place resource volume but low recovery factor; little water production; geologically controlled sweet spots; reservoirs commonly in close proximity to mature source rocks; reservoirs with very low matrix permeabilities; and water occurring updip from hydrocarbons. The Niobrara Petroleum System meets all these characteristics.

The Niobrara is equivalent to the First White Specs of the western Canadian Basin and the Austin Chalk of the Gulf Coast.

Knowledge of the distribution and occurrence of hydrocarbon source and reservoir rocks in the Niobrara interval will greatly aid future exploration.

Regional setting

The Upper Cretaceous Niobrara (about 82 million to 89.5 million years ago) was deposited in a foreland basin setting in the WIC Seaway of North America during a major marine transgression. This major transgression probably represents the maximum sea level highstand during the Cretaceous and might contain the best source rocks in the Cretaceous.

The WIC Basin was an asymmetric foreland basin with the thickest strata being deposited along the western margin of the basin (figures 1 and 2). The WIC Basin is a complex foreland basin that developed between Mid- to Late Jurassic to Late Cretaceous time. The basin was bordered by mountainous areas to the west (zone of plutonism, volcanism and thrusting that formed the Cordilleran thrust belt) and a broad stable cratonic zone to the east. The foreland basin subsided in response to thrust and synorogenic sediment loading and pulses of rapid subduction and shallow mantle flow.

Stratigraphy and depositional setting

The Niobrara represents one of the two most widespread marine invasions and the last great carbonate-producing episode of the WIC Basin (the first widespread event is represented by the Greenhorn chalks). The dominant lithologies of the Niobrara Formation are limestones (chalks), marls and interbedded calcareous shales. The chalk-shale cycles are interpreted to represent changes from normal to brackish water salinities possibly related to regional paleoclimatic factors or sea level fluctuations. The chalk lithologies are thought to represent deposition in normal to near-normal marine salinities having a well-mixed water column and well-oxygenated bottom waters. The chalks reflect an influx of warm Gulfian currents into the WIC Seaway during relatively high

The Niobrara in the WIC Basin

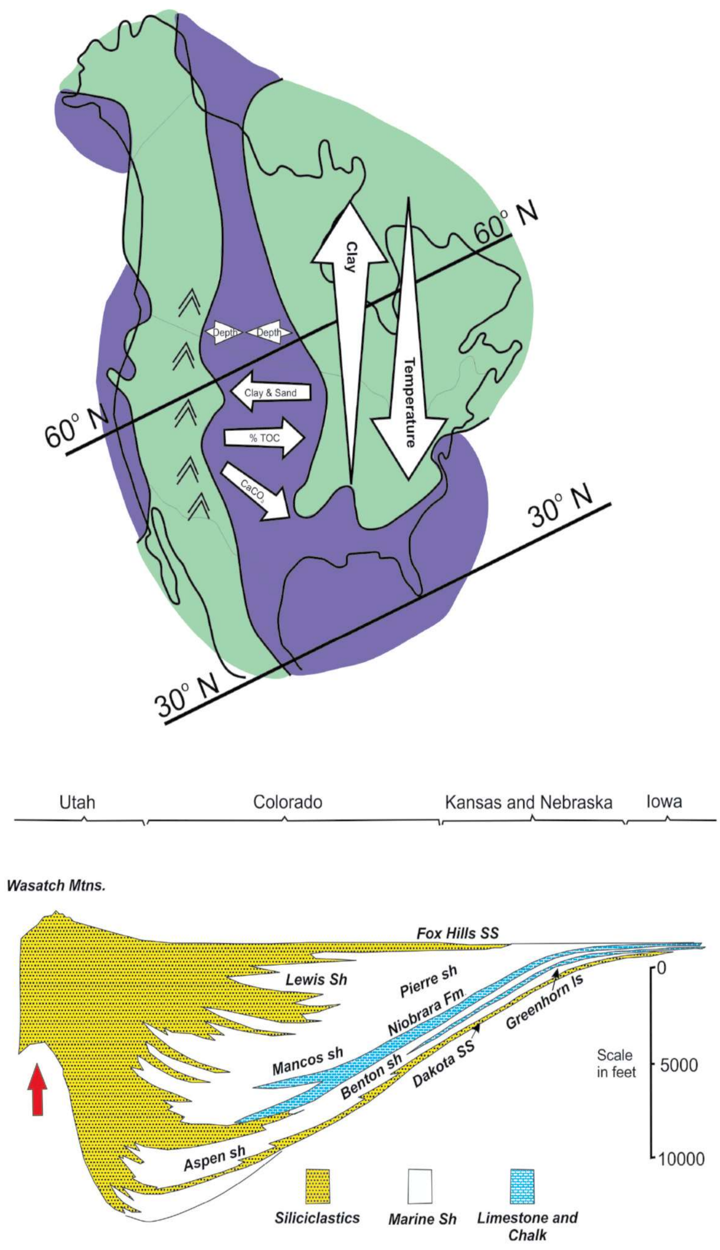


Figure 1. A) The WIC Basin during Niobrara time is shown *(modified from Longman et al., 1990)*. The source area for clastics is dominantly to the west. TOC content in the Niobrara increases to the east, and carbonate content generally increases on the eastern side of the WIC Seaway and to the southeast. B) A generalized cross section across the WIC Basin is shown. The Niobrara is Upper Cretaceous in age. Limestone and chalk beds are present over the eastern two-thirds of the basin. *(Data modified from Kauffman, 1977)*

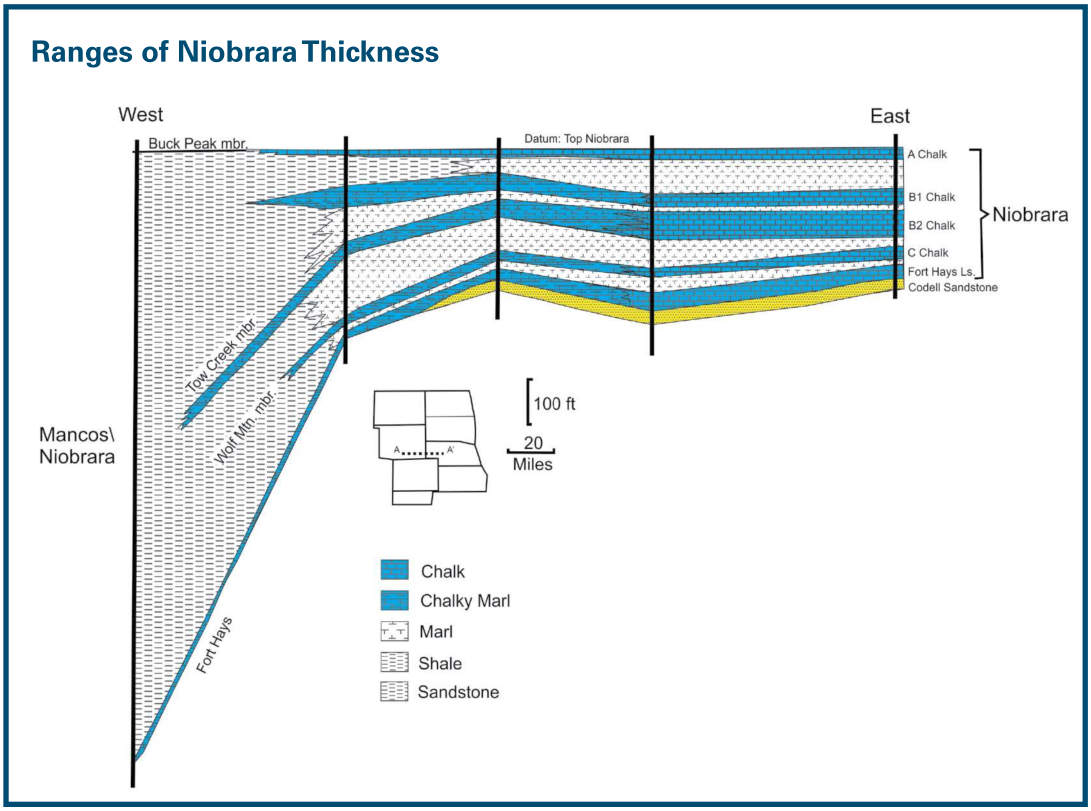


Figure 2. A west-to-east cross section across western Nebraska and southern Wyoming shows various units in the Niobrara and dramatic thickening of the total Niobrara section to the west. Datum top Niobrara. *(Data modified from Longman et al., 1999)*

sea levels. The interbedded shale cycles are interpreted to be caused by an increase in freshwater runoff caused by increased rainfall, which might be related to climatic warming. The freshwater runoff creates a brackish water cap and salinity stratification. Vertical mixing of the water column is inhibited, causing anoxic conditions in the bottom waters. This enhances preservation of organic material and results in organic-rich source rocks. The decrease in water salinities also is suggested by oxygen isotopic values. The shalier intervals might reflect lower sea levels and greater influx of clastic material from the west. The chalks have previously been interpreted to represent higher sea levels during Niobrara time.

Three major facies are present in the Niobrara and equivalents across the Rocky Mountain region (figures 1 and 2). On the western side of the area, a sandstone facies is present, which changes laterally to the east into a calcareous shale facies, and which, in turn, changes eastward into a limestone and chalk facies.

The chalks of the Niobrara are rich in organic matter (TOC) and organic-related material (e.g., pyrite). On the east side of the WIC Basin, the Niobrara consists of four chalk beds (A, B, C and Fort Hays) and three shale intervals (Figure 2). The basal chalk bed is known as the Fort Hays limestone member, and the unit contains some of the purest chalk in the WIC. On the western side of the area, the chalks are referred to as the Buck Peak, Tow Creek, Wolf Mountain and Fort Hays members (Figure 2).

The Fort Hays is overlain by the Smoky Hill Member (A, B, C chalks and marls). The Smoky Hill consists of organic-rich shales to chalky shale (marls) to massive chalk beds. The interval has been subdivided by various authors into several units. Figure 2 illustrates the subdivisions.

The Niobrara ranges in thickness from 100 ft to 300 ft along the eastern side of the WIC Basin to more than 1,500 ft on the west side of the WIC Basin (figures 2 and 3). Figure 3 illustrates an isopach map of the Niobrara across the northern Rockies region. Thinning occurs in a broad northeast trend across the map area. This thin trend was related to paleotectonic movement on the Transcontinental Arch. Thinning in the Niobrara is believed to result from differing rates of sedimentation (i.e., convergence or divergence of a section) and unconformities at the base, within and at the top of the formation.

Niobrara deposition in the WIC Basin was strongly influenced by the interplay of warm north-flowing currents from the paleo-Gulf of Mexico (GoM) and cooler southward-flowing currents from the Arctic region along with sea level fluctuations (Figure 1). Warm waters from the GoM brought in rich carbonate flora of coccoliths and promoted carbonate production and deposition. Siliciclastic input from the west and cooler Arctic currents inhibited carbonate production and deposition.

The Niobrara is overlain by the Pierre Shale in the eastern part of the WIC Basin and the Mancos Shale in the western part. The Niobrara overlies the Carlile Formation across much of the WIC Basin (and its members, the Codell Sandstone, Sage Breaks Shale, etc.). The Sharon Springs member of the Pierre Shale overlies the Niobrara in most of eastern Colorado. The Sharon Springs is an excellent source rock with TOCs ranging from 2 weight percent (wt.%) to 8 wt.%.

Source rocks

The Niobrara produces self-sourced oil and gas from tight (low-porosity and low-permeability), fractured, carbonate reservoirs. Niobrara source rocks are dominantly Type-II, oil-prone kerogen. The richest source rocks are in the Denver Basin where the TOC content reaches 8 wt.%. In south-central Wyoming, the TOC content averages 2.1 wt.%. The 700-ft Niobrara section in northwest Colorado has good source rock potential. Source rocks in southwestern Wyoming are dominantly Type-II with some mixing from Type-III, gas-prone kerogen. The average TOC content from samples in southwest Wyoming is 1.85 wt.%.

Reservoir rocks

The lithology of the Niobrara changes from west to east across the WIC Basin (Figure 2). In the Denver Basin, the lithology consists of interbedded calcareous shale, shaley limestones, marls and limestones. Westward, the lithology becomes shalier and sandier. The carbonates are still present in the western area, but clastics (sands and shale) begin to dominate.

Most of the Niobrara reservoir rocks have undergone mechanical and chemical compaction and are low-porosity and low-permeability rocks. Burial depth is the single most important factor affecting porosity in the Niobrara. Chalks have high original porosities (50% or greater). Initial dewatering and mechanical compaction make up the first diagenetic phase. Grain and fossil breakage and re-orientation reduce porosity. Initial coccolith grain sizes are 0.2 µ to 1 µ. Chemical compaction is characterized by calcite dissolution along wispy dissolution seams, microstylolites and stylolites. Grain-to-grain dissolution along microstylolites is common, and the dissolved calcite is reprecipitated locally. The chalks have an average porosity of 6% at 7,000 ft. Both shallow and deeply buried chalks have low permeabilities (less than 1 mD). The ini-

Isopach Map of the Niobrara

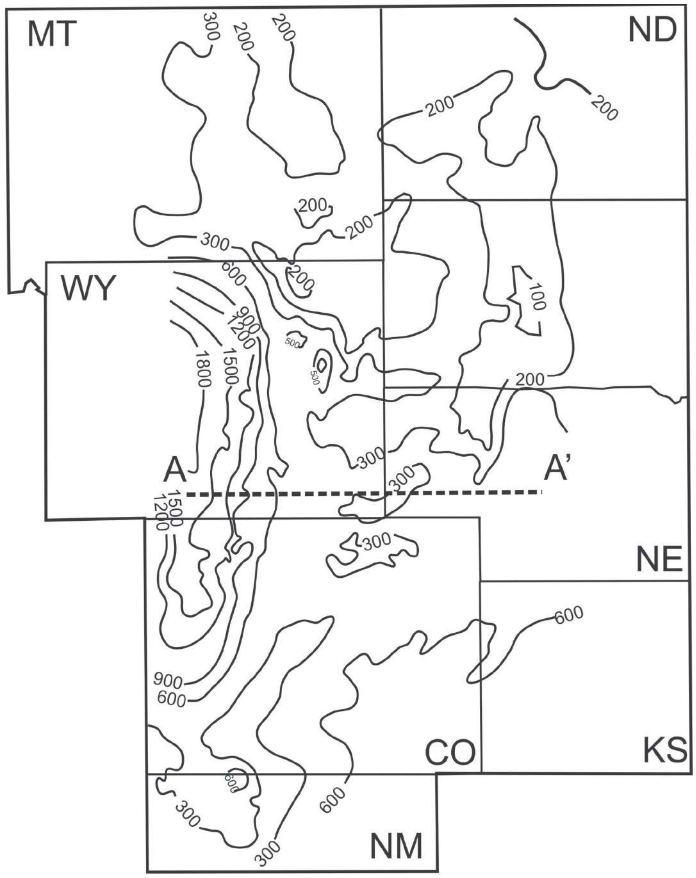


Figure 3. An isopach map of the Niobrara across the northern Rockies is shown. The Niobrara ranges in thickness from less than 100 ft to more than 1,800 ft. See Figure 2 for the cross section. *(Data modified from Longman et al., 1999)*

Niobrara Producing Areas

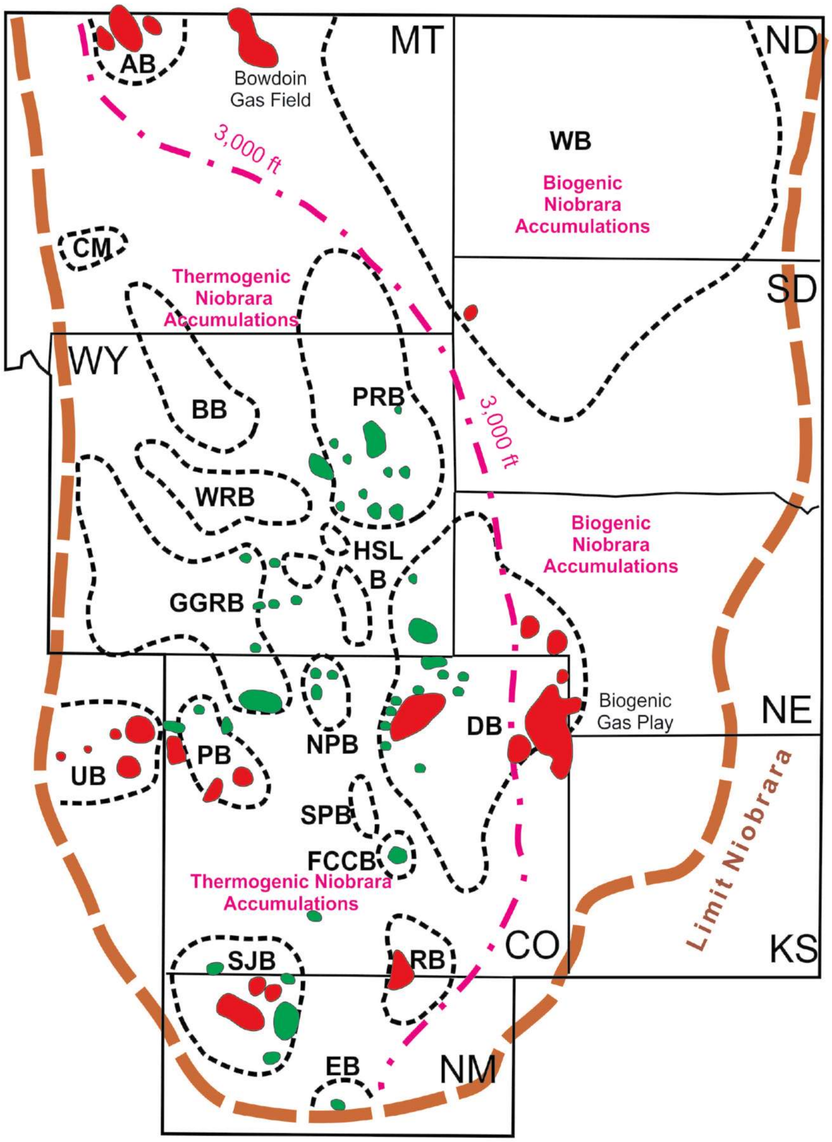


Figure 4. Niobrara producing areas across the north Rockies are illustrated. Oil fields are in green, and gas fields are in red. Basin abbreviations are as follows: AB-Alberta Basin; CM-Crazy Mountain; WB-Williston Basin; BB-Bighorn Basin; PRB-Powder River Basin; WRB-Wind River Basin; GGRB-Greater Green River Basin; NPB-North Park Basin; PB-Piceance Basin; UB-Uinta Basin; SPB-South Park Basin; FCCB-Florence-Canon City Basin; SJB-San Juan Basin; RB-Raton Basin; DB-Denver Basin; and EB-Estancia Basin. The distribution of sapropelic oil-generation-prone Niobrara source rocks is within the brown-dashed line. The dot-dashed line equals 3,000-ft current burial depth. Biogenic accumulations are east of the line, and thermogenic accumulations are west of the line. *(Data courtesy of Longman et al., 1998; Meissner et al., 1984; and Lockridge and Scholle, 1978)*

tial average pore throat sizes are a few tenths of a micron, which are further reduced with diagenesis.

Hydrocarbon production

Hydrocarbon production comes from all three major Niobrara lithofacies: microporous and fractured coccolith-rich and planktonic foraminifer-rich limestone (eastern part of the WIC Basin); fractured marls and shales (mainly in the central part of the seaway); and fractured sandstone and siltstone-rich facies, mainly in the western and southwestern parts of the seaway (Figure 1). Production occurs in the Laramide-aged Powder River, Denver, North Park, Greater Green River (including Sand Wash), Raton, San Juan and Piceance basins and in north-central Montana. The widespread distribution of the production along with many wells with hydrocarbon shows across these basins suggests a large resource play might exist.

Niobrara production represents some of the oldest established production in the Rocky Mountain region (Figure 4, Table 1). Fractured Mancos/Niobrara production was found in Rangely in northwest Colorado in 1902. Production was found in the "upper shale" (Niobrara) at Salt Creek in 1907. Gas was found in the Niobrara in Bowdoin in 1913. Niobrara production was established in Tow Creek in the Sand Wash Basin in 1924. The Berthoud Field of the western Denver Basin is productive from several horizons, including the Niobrara, and was discovered in 1927. Gas in the Niobrara was discovered in Beecher Island (eastern Colorado) in 1919 (commerciality was not established until 1972, however). Buck Peak was discovered in 1956. Loveland Field production from several horizons, including the Niobrara, was discovered in 1957. The reason for these early discoveries is that many of them are associated with surface structures, which were the primary targets of early explorers.

Biogenic gas production from chalk reservoirs occurs along the shallow eastern margin of the Denver Basin. Many of the gas accumulations in this area occur in structural traps, and reservoirs require hydraulic-fracture stimulation. Production in the shallow play comes from the upper chalk bench (A bench) or Beecher Island member of the Niobrara and is mainly from microporosity within the chalks but is enhanced by natural fracturing. Production from the shallow Niobrara from eastern Colorado is in excess of 600 Bcf of gas. Beecher Island Field is one of the largest and first fields discovered in the shallow Niobrara. Commercial production dates back to 1972 (initial discovery in 1919), and the cumulative for the field is 124 Bcf of gas. Three-dimensional seismic data have been used effectively to improve development and exploration success ratios in fields.

Selected Niobrara Fields in the Rocky Mountain Region

Field	Basin	Discovery	Cum Oil	Cum Gas	Comments
Rangely	Douglas Crk Arch	1902	11.9 MMbbl of oil	0.2 Bcf	structure
Salt Creek (Niobrara)	Casper Arch	1907	1.5 MMbbl of oil	0.2 Bcf	"upper shale"
Bowdoin	Cent. MT	1913	62 Bcf		Biogenic gas (?)
Tow Creek	Sandwash	1924	3 MMbbl of oil	0.3 Bcf	
Berthoud	Denver	1927	48 Mbbl of oil	0.2 Bcf	
Buck Peak	Sandwash	1956	4.7 MMbbl of oil	8.2 Bcf	
Loveland	Denver	1957	1.4 MMbbl of oil	8.4 Bcf	
Puerto Chiquito	San Juan	1960	19.3 MMbbl of oil	55.5 Bcf	
Beecher Island	Denver	1972		124 Bcf	Biogenic gas
Wattenberg (Niobrara)	Denver	1980	96 MMbbl of oil	1.3 Tcf	Basin-center oil and gas
Silo	Denver	1981	10.5 MMbbl of oil	9.3 Bcf	Horizontal drilling 1990s

Table 1. The table shows the basin, which field it is located in and its discovery date. The Wattenberg and Silo fields are significant in that they show the continuous, basin-center type of an accumulation that occurs in the Niobrara. *(Images by Stephen A. Sonnenberg unless otherwise noted)*

Shallow biogenic gas production from the Niobrara also occurs in north-central Montana including Bowdoin Dome. Bowdoin Dome has produced 62 Bcf of gas and 19 Mbbl of oil from the Niobrara and Niobrara equivalents.

Deeper in the Denver Basin, the Niobrara is producing oil in a number of fields. The porosity of the chalks in the deeper part of the basin has been dramatically reduced by compaction and burial diagenesis. Production is attributed to the presence matrix porosity and fractures in the chalky intervals. The petroleum potential of the deep Denver Basin area is significant as shown by fields like Wattenberg and Silo. Wattenberg Niobrara cumulative production is in excess of 96 MMbbl of oil and 1.3 Tcf of gas. The Silo Field was discovered in 1981 and has produced about 10.5 MMbbl of oil and 9.3 Bcf of gas. The Wattenberg and Silo fields are significant because both fields are located in basin-center types of settings. This illustrates and suggests the deep potential of the Niobrara in most of the Rocky Mountain basins.

The Niobrara is productive on the Casper Arch of Wyoming at the Salt Creek and Teapot fields. Total production has been 1.5 MMbbl of oil and 200 MMcf of gas. In the deeper Powder River Basin, production has been established in a number of accumulations including Fetter, Hilight, Brooks Draw and Flat Top. Primary operators to date have been Chesapeake, Anadarko and EOG. Hilight Field, also located in the Powder River Basin, has produced more than 411 Mbbl of oil and 800 MMcf of gas to date from the Niobrara.

The western part of the region is productive in a variety of traps and lithologies (mainly siliciclastic), and there is significant potential for hydrocarbon production in many of the western Rockies basins. The basal part of the Niobrara equivalent yields oil and gas in the San Juan Basin from a sandstone and shale interval (Tocito and Gallup sandstones). Examples of producing fields from the Gallup are the Bisti and Verde fields. The Bisti Field has produced 41.8 MMbbl of oil and 79.2 Bcf of gas. The Verde Field has produced 8.1 MMbbl of oil and 2.5 Bcf of gas. Examples of fields producing from

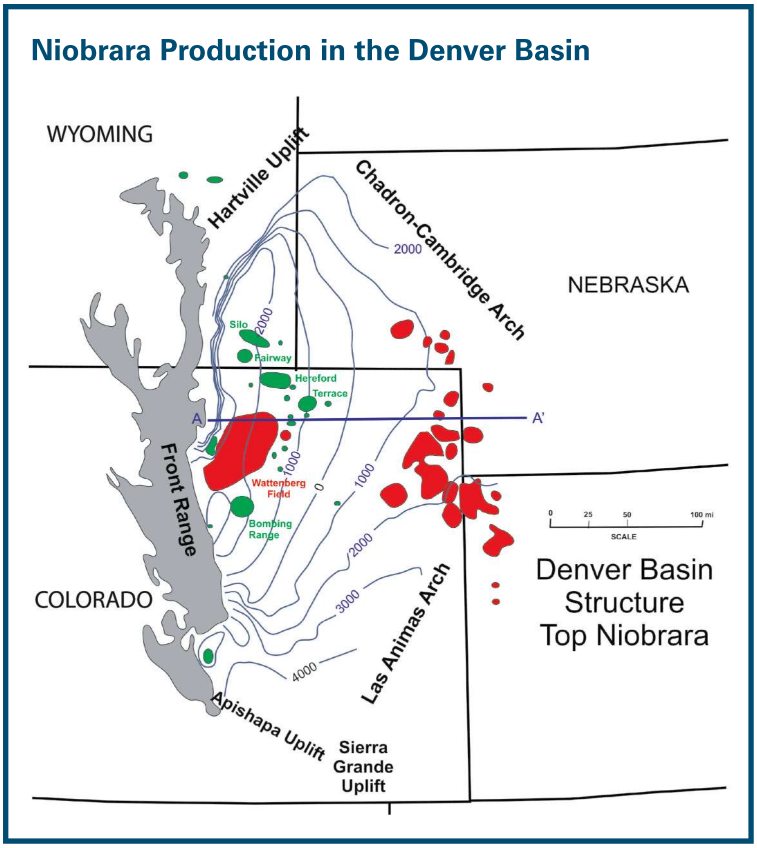


Figure 5. A structure contour map shows areas of Niobrara production. New horizontal wells are being drilled in the Wattenberg, Fairway, Hereford, Terrace and Bombing Range areas.

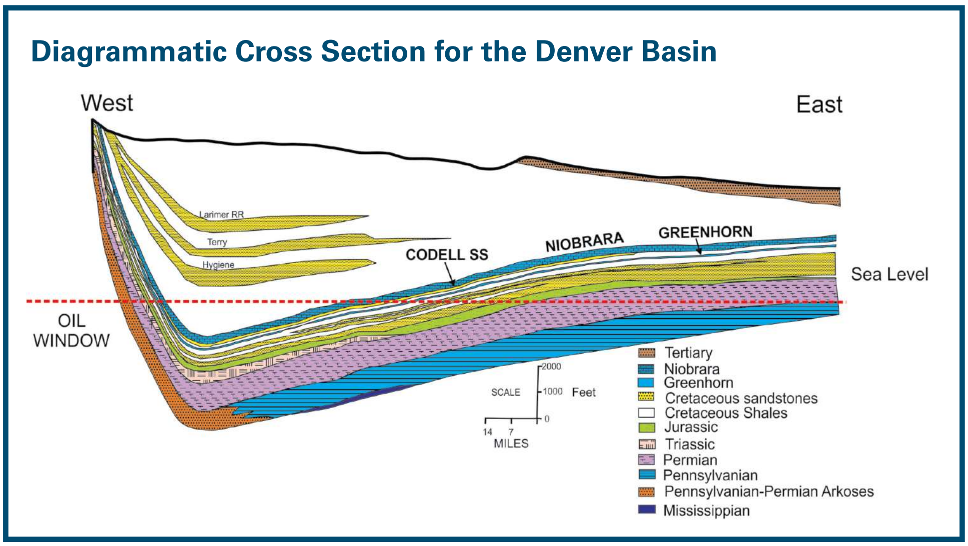


Figure 6. A diagrammatic cross section for the Denver Basin is shown. The Niobrara Petroleum System consists of reservoirs in the Niobrara, Terry, Hygiene and Larimer Rocky Ridge areas as well as source beds in the Niobrara. Shallow biogenic accumulations in the Niobrara are found on the east flank of the basin where source beds are immature.

the Tocito Sandstone are the Blanco South and Chipeta fields. These fields have produced 4.2 MMbbl of oil and 18.8 Bcf of gas. Production is from interparticle porosity but is enhanced by fractures. The upper Niobrara equivalent (Smoky Hill member) is productive in the Sand Wash Basin from fractured reservoirs (Figure 4), and perforated intervals are commonly long (Buck Peak, Tow Creek and Wolf Mountain members). Field examples are Buck Peak and Tow Creek. Buck Peak has produced 4.8 MMbbl of oil and 8.5 Bcf of gas. Tow Creek has produced 3 MMbbl of oil and 300 MMcf of gas. Neogene age extensional faulting is a key to production at Buck Peak and Rangely. The extensional fracture trend is N60W. Production from the fractured Mancos Shale at Rangely represents some of the oldest production in Colorado (1902). The Mancos/Niobrara at Rangely has produced about 11.9 MMbbl of oil and 200 MMcf of gas.

Other production equivalent to the upper Niobrara zone comes from the Mancos interval in the San Juan Basin. Examples of Mancos producing fields are East and West Puerto Chiquito, Rio Puerco, Gavilan, Basin and Boulder. These fields are interpreted to be fractured reservoirs, and producing intervals are hundreds of feet thick. The Puerto Chiquito fields have produced 19.3 MMbbl of oil and 55.5 Bcf of gas. The Gavilan Field has produced 7.8 MMbbl of oil and 111 Bcf of gas. The Boulder Field has produced 1.8 MMbbl of oil and 1.6 Bcf of gas. The Basin Field has produced 120 Mbbl of oil and 4.1 Bcf of gas. The Rio Puerco Field has produced 1.3 MMbbl of oil and 1.4 Tcf of gas.

The Mancos is gas productive in the deeper parts of the Uinta Basin in several fields including the Natural Buttes. The Mancos also is productive in some silty and very fine-grained sandstone zones in the Cathedral Field of the Douglas Creek Arch.

The majority of recent horizontal drilling activity in the Niobrara has been in the Denver Basin (figures 5, 6, and 7), in the Wattenberg Field (Anadarko, Noble, PDC, Encana and other smaller operators), northeast of the Wattenberg Field (Terrace Field area, Noble and Whiting), and in southeast Wyoming south of the Silo Field (Cirque and EOG). The Hereford Field, north of the Wattenberg and just south of the Wyoming state line, is being developed by EOG. Main targets in the Denver Basin are the B and C chalks. Recent activity also is targeting the Codell/Fort Hays interval (common source of supply) with great success. The resource potential might exceed 5 Bboe from the deep Niobrara/Codell intervals of the Denver Basin. The southern Powder River Basin is seeing activity targeting the B Chalk interval by Chesapeake, Anadarko and others. The Sand Wash Basin is seeing drilling by Southwestern Energy (which bought Axia last year). The Piceance Basin is seeing horizontal activity from WPX and Endeavor. The San Juan Basin is seeing horizontal drilling activity from Encana and WPX.

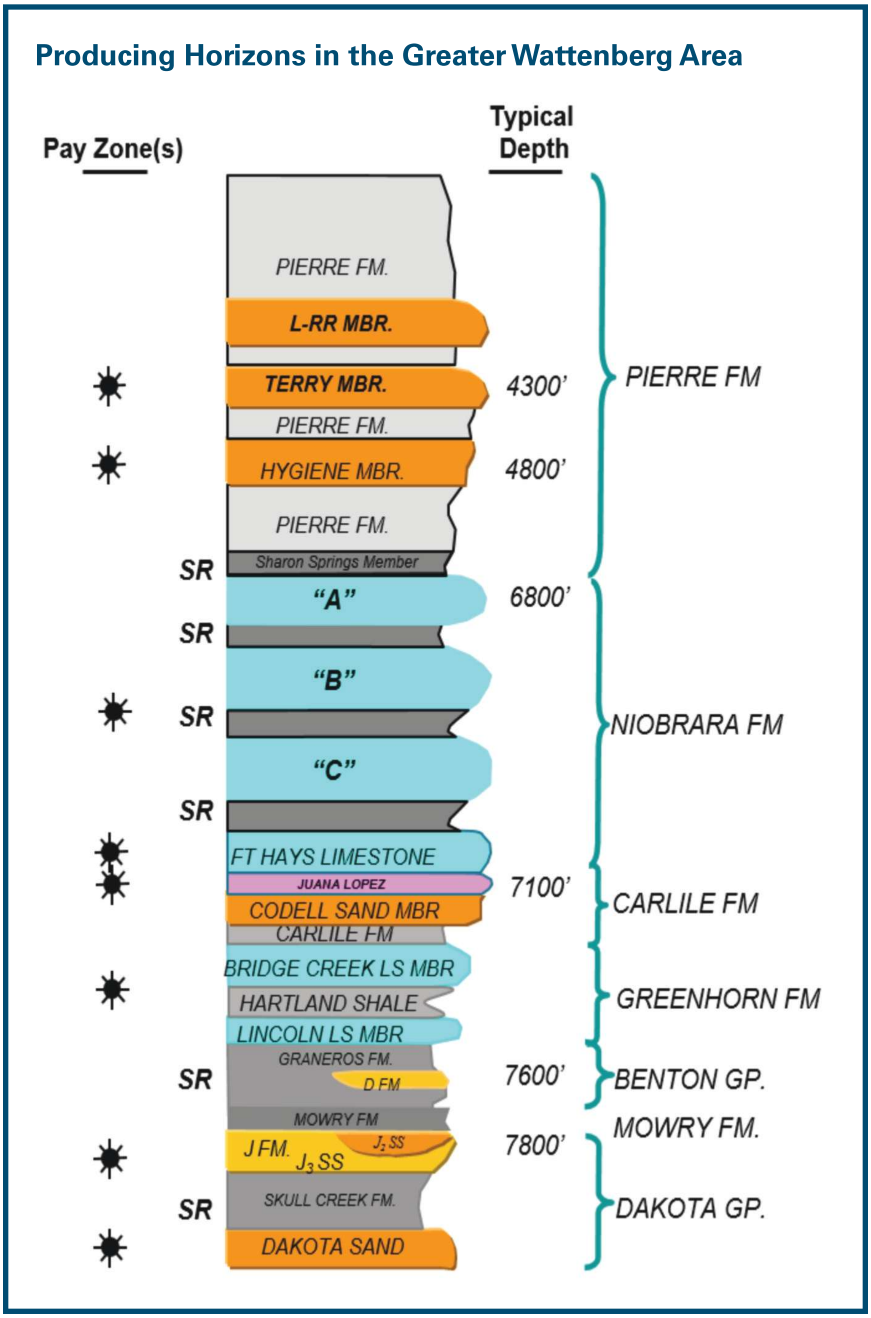


Figure 7. A stratigraphic column for producing horizons in the greater Wattenberg area is shown. The Niobrara consists of four limestone (chalk) beds and three organic rich calcareous shale intervals (marls). The basal Pierre Shale also has an excellent source bed (Sharon Springs).

Summary

Widespread source and reservoir rocks make the Niobrara Formation an attractive target for exploration across the Rocky Mountain region. The Niobrara contains mature source rocks interbedded with brittle limestones (chalks) in the deeper parts of many basins in the Rocky Mountain region. Thermogenic production occurs from the chalk intervals in the deeper parts of many basins and from siliciclastics and shales in the western and southwestern parts of the Rocky Mountain regions (Uinta and San Juan basins). Continuous, basin-center types of accumulations from the Niobrara Formation occur in most Rocky Mountain basins. Biogenic gas production occurs at shallow depths along the eastern Rocky Mountain region in Colorado, Kansas and Nebraska. Generally, production comes from depths less than 3,500 ft. Shallow gas production also occurs in several areas of north-central Montana. The shallow gas production generally is structurally controlled. ■

Operators **Clamor** for **Rockies Oil**

The Rocky Mountain region boasts two of the hottest horizontal drilling oil plays in the nation.

By Don Lyle
Contributing Editor

The Bakken/Three Forks and the Codell/Niobrara Shale combination plays offer oil and gas E&P companies two of the best profit opportunities in the industry.

Both plays respond to horizontal drilling and multistage completion techniques that continue to evolve and offer higher IP and ultimate recoveries. Pad drilling and high-efficiency, factory-type drilling and production techniques lower costs and increase profits.

As for differences, the Codell/Niobrara combination is shallower than the Bakken/Three Forks and less expensive, creating a foothold for operators with shallower pockets. While the Williston Basin faces constraints to transportation to markets and operators often must resort to rail cars, the Denver-Julesburg Basin has plenty of free pipeline capacity and ready access to markets.

In this section of the playbook, Hart Energy examines the producers in each of these prolific production areas to find out what they like about the plays, how they enhance recoveries and profits, and where they see the plays developing in the future.

Key Players

Anadarko Petroleum Corp.

- **Horizontal wells reach for profits**
- **Large fee acreage boosts bottom line**

Anadarko Petroleum Corp. dipped its drillbits in some of the most prolific and profitable plays in the U.S., and a fortunate acquisition made the Rocky Mountains even more profitable.

The acquisition of Union Pacific Resources gave Anadarko a huge chunk of fee acreage on both sides of the Union Pacific Railroad track, running from southeastern Colorado northwest through the Denver-Julesberg Basin and west across the northern border of Wyoming. The railroad received the land when it connected rail lines from the east to the west across the nation.

Niobrara

Part of that land position is the company's 350,000 net acres in the Denver Basin, a position that gives the company an estimated 1 Bboe to 1.5 Bboe in resource potential, primarily from the Niobrara and Codell formations.

Wattenberg Field, one of the most prolific gas fields in the U.S. for decades, has expanded into the heart of the Niobrara and Codell oil play. That's where Anadarko's properties lie.

According to Anadarko, "Every characteristic of the Wattenberg HZ [horizontal] program aligns to make it among the largest and most important oil and natural gas development projects in the company's U.S. portfolio.

Translated into benefits to shareholders, "important" means the properties in the light oil area of the field return more than 100%.

A rig on the plains northeast of Denver looks for Niobrara oil in the giant Wattenberg Field. *(Photo courtesy of Anadarko Petroleum Corp.)*

Anadarko is taking advantage of that potential by operating about 13 drilling rigs to drill more than 360 wells in the Wattenberg Field in 2014. Its base operation offers a 1 Bboe trove of oil, and downspacing gives the company the potential to produce another 500 MMboe.

The company's operations have resulted in more than a 20% compound annual growth rate in sales volumes.

Some 3,125 miles of gas gathering lines and 157 miles of oil gathering lines along with 575 MMcf/d of gas processing capacity and 125,000 hp of compression support its production operations. The gas gathering system can handle 525 MMcf/d, and the oil gathering system has a capacity of 125 Mbbl/d of oil.

A recent addition to that infrastructure is the 300 MMcf/d Lancaster cryogenic plant that feeds the 150 Mbbl/d NGL pipeline and the 75 Mbbl/d White Cliffs Pipeline. The company is adding 300 MMcf/d of cryogenic processing capacity at the Lancaster II plant.

The company produced 56 Mboe/d from the field in 2013.

The railroad land grant made Anadarko one of Wyoming's largest landholders, but its primary properties with Niobrara potential don't lie along the grant properties. Instead, they are in the Powder River Basin to the northeast.

The company is moving more slowly in developing the Wyoming properties than its Colorado properties. It had only three operated rigs at work and produced oil from 19 wells in second-quarter 2014.

It is testing multiple formations in the stacked pay in the area, including the Parkman, Shannon, Niobrara and Frontier/Turner.

Bill Barrett Corp.

- **Working the Denver-Julesburg since 2011**
- **Adding new properties**

Bill Barrett Corp., based in Denver, boasts a remarkable history of strong operations based on sound and often innovative geology.

Among its historic operations are the opening of key Wind River Basin deep plays in Wyoming and the opening of the Piceance Basin in Colorado after the oil shale industry shut down.

The company carries that work into its Niobrara and Codell operations.

Niobrara

Barrett holds 84,450 net acres with Niobrara potential, including a 7,856-net-acre parcel in the northeast Wattenberg Field in third-quarter 2014. Most of those properties are in the northeast Wattenberg area and along the Colorado-Wyoming border, but the company also owns properties in northern and southern Wattenberg.

By year-end 2013, the company held some 77 MMboe in estimated proved reserves and 224 MMboe of risked resource. It produced 1.28 MMboe in 2013. At that time, its properties supported some 1,697 gross drilling locations.

In the company's third-quarter 2014 report to shareholders, it said it grew production from the Denver-Julesburg Basin by 150% to about 8.3 Mboe/d, including 390 boe/d from the third-quarter acquisition alone.

It currently holds 49,365 net acres in northeast Wattenberg, 22,680 net acres at Chalk Bluffs and 12,405 net acres in the Wattenberg interior.

It drilled four mid-length lateral (7,300-ft) wells and 23 more wells with extended-reach laterals during third-quarter 2014.

The mid-length lateral wells tested for an average 548 boe/d on their first 30 days online. That figure met Barrett's expectation.

By third-quarter 2014, the company set plans to dedicate 75% of its capital spending to the Niobrara/Codell play. It planned to use that money to drill about 65 gross (53 net) new wells and participate in 47 gross (nine net) nonoperated wells.

By November 2014, Barrett had spudded 29 extended-reach laterals, 15 of them in its northern block and 14 in the southern block of northeast Wattenberg. Its average drilling time was 16.7 days for the 9,300-ft lateral wells drilled to the Niobrara B and C benches.

A four-well pad drilled with medium-length laterals gave the company an initial potential of 770 boe/d, a 30-day IP rate of 548 boe/d and a 60-day rate of 447 boe/d.

Currently, Barrett is testing tighter downspacing on its southern block as it drills 7,300-ft laterals to the Niobrara B and C benches. It plans to drill to the Codell.

The company noted its property is next to Noble's Wells Ranch, where 40-acre spacing has been tested within 3 miles of Barrett's properties.

Bonanza Creek Energy Inc.

- **Denver and North Park Basin leaseholder**
- **Emphasis on the Niobrara**

Bonanza Creek Energy Inc. picked a prime spot in the Niobrara play, right in the oil-weighted extension section of the field.

Niobrara

The acreage is prospective for all the Niobrara benches and some Codell, although the Codell Formation thins toward the east. It is being developed on the western half of Bonanza Creek's position in the field. It can drill 3,500 gross wells on its Wattenberg properties.

Its 126,400 gross (70,100 net) acres in the northeast Wattenberg area make it the fourth largest leaseholder in the Wattenberg Field. The acreage is "largely contiguous."

According to a November 2014 presentation, the company has drilled more than 200 operated wells and produced about 20 Mboe/d by third-quarter 2014.

The Wattenberg play has given the company a 102% compound annual growth rate since fourth-quarter 2011.

Bonanza Creek is developing the Niobrara B and C benches and the Codell on its Denver-Julesburg

(DJ) Basin property, mainly with 4,000-ft horizontal legs on its wells, but it is testing extended-reach wells and downspacing to increase recoveries. It also is testing the Niobrara A bench.

Under its 2014 plan, Bonanza Creek planned to drill 121 operated and 19 nonoperated wells at Wattenberg using 75% of its $630 million to $680 million capital budget to run four drilling rigs.

It also holds some property prospective for Niobrara production in the North Park Basin along the Wyoming border and west of the DJ Basin.

That basin has produced oil from anticline traps in the Muddy Sand in North McCallum and South McCallum fields.

The Niobrara also occurs beneath the company's property. It is evaluating that formation.

Overall, Bonanza Creek has 308 MMboe in net horizontal proved, probable and possible reserves, and 46 MMboe of that number consist of proved reserves.

Carrizo Oil & Gas Inc.

- **More spending and more production**
- **Denver Basin contributes to growth**

Carrizo Oil & Gas Inc. put the largest chunk of its capital budget into the Eagle Ford Formation in South Texas, but its northeastern Colorado properties made a solid enough contribution that Carrizo boosted its spending in the area.

Niobrara

The company holds 39,300 net acres with 5.5 MMboe in proved reserves in the Denver-Julesburg Basin. Only the Eagle Ford holds a higher acreage position in its portfolio, according to a November 2014 presentation.

It spent $66 million on its Niobrara properties in 2013 and raised that number to $95 million in 2014. That spending level allowed Carrizo to drill 33 gross (11 net) wells and fracture 38 gross (14 net) wells bringing its total count to 114 gross (47 net) wells with four gross (two net) wells awaiting completion in November.

Carrizo isn't just following an established pattern; it's also testing techniques to improve its results. It tested 40-acre spacing during 2014 after confirming positive results with 50-acre well spacing.

It had been working the B and C benches of the Niobrara, but its first A bench well tested with an IP rate of 1.1 Mboe/d with an 88% oil cut.

During third-quarter 2014, Carrizo began producing from A and B benches on 40-acre spacing and found no communication between the two zones, indicating they can be produced as separate reservoirs.

The company also works with its neighbors; it participated in super pads with Noble and Whiting in drilling the A, B and C benches.

Of the company's 20 Mbbl/d record oil production in third-quarter 2014, 2.3 Mbbl/d of oil came from its Niobrara operations, a 5% gain from the previous quarter. It is operating one drilling rig in Colorado.

Chesapeake Energy Corp.

- **Southern Powder River Basin operator**
- **Niobrara ranks fifth in priority**

The Niobrara and other Upper Cretaceous formations might not rank high on Chesapeake Energy's list of top plays, but they are on the list and improving.

Located in the southern Powder River Basin of northeastern Wyoming, the region attracted only 5% of the company's $4.5 billion E&P budget in 2014 behind its Eagle Ford, Midcontinent, Utica, Marcellus North and Haynesville operations.

Niobrara and Upper Cretaceous plays

Chesapeake drilled 31 wells in the Niobrara in 2012, 38 wells in 2013 and 41 wells in 2014 as drilling and completion costs fell. With three rigs at work, it produced nearly 14 Mboe/d from the formation in third-quarter 2014, according to a November 2014 presentation.

Additionally, third-quarter 2014 net production from the Rocky Mountain region reached 13.9 Mboe/d from 150 drilled locations on its recently extended position of 388,000 net acres. In August 2014, Chesapeake exchanged its nonoperated properties in the northern Powder River Basin and $459 million in cash for RKI Exploration & Production's southern Powder River Basin acreage.

In addition to incremental Niobrara drilling locations, the company acquired prospective leasehold above stacked and staggered liquids-rich formations referred to as Upper Cretaceous. Powder River Basin properties offer stacked and staggered liquids-rich formations. The company already has delineated the Sussex play through successful exploratory wells and intends to test other formations, including the Teapot, Shannon and Parkman, in 2015.

According to the company's website, "Drilling and completion cost improvements have dramatically changed well economics, and Chesapeake plans to increase activity throughout 2015. Chesapeake has more than 450 MMboe of net recoverable resources in the basin."

In its third-quarter 2014 report, Chesapeake said the Eagle Ford, Haynesville, Utica and Powder River Basin operating areas each provided more than 10% growth quarter to quarter. The actual quarter-to-quarter growth for the Powder River Basin was 16%, adjusted for an agreement with RKI, and the region shows a gain of 26%.

Chesapeake anticipated further production increases when its Buckinghorse processing plant came onstream in November 2014 with a processing capacity of some 120 MMcf/d of gas.

The company completed an average horizontal well in the basin for $9.2 million between January and July with an average lateral reach of 5,300 ft. It completed the average well with 17 fracture stages. The completed well price dropped by $900,000 from the average 2013 price. The 2013 wells had a lateral length of 5,050 ft and 15 fracture stages.

Chesapeake planned to finish 2014 with an average well cost of $8.9 million. The average peak production rate of the 17 wells that began producing in third-quarter 2014 was about 1.5 Mboe/d.

Cirque Resources LP

- **Key leaseholder in southern Wyoming**
- **Tapping the Codell for profits**

Cirque Resources LP focused its attention on its Brennsee Project, a Codell oil play in northern Weld County, Colo., and Laramie County, Wyo.

Codell

"Much like the Williston Basin's Bakken and Three Forks multiple oil reservoirs, the Brennsee project area contains multiple oil reservoirs with expected increased density for long-term, low-risk, high-return and multidecade development potential," according to the company's website.

The company has several producing horizontal oil wells on the property.

A report by Wunderlich Securities identifies four sweet spots in the Denver-Julesburg Basin. They include the Wattenberg Field, northeast Wattenberg, northeastern Colorado along the Wyoming border and Laramie County, Wyo.

Cirque's properties are in the Laramie County sweet spot with EOG Resources, Anadarko Petroleum and Kaiser Francis.

In that area, EOG's Windy 504-1806 tested for 1.5 Mboe/d from the Codell with a 7% gas cut.

Cirque holds 90,000 net acres in the area. According to Wunderlich, the property also is prospective for Niobrara production from the C bench. The company drilled eight Codell wells in 2012 and ran one rig in 2014 with plans to drill up to 12 wells.

Wunderlich said the company plans to ramp up production and put the project on the market by early 2015.

ConocoPhillips Co.

- **Working four focused Lower 48 plays**
- **Bakken and Niobrara head Rockies action**

ConocoPhillips Co. offers a simple, straightforward reason for its investments in unconventional plays in North America: That's where the highest investment margins lie.

In the U.S., those high margins come from the Eagle Ford, Permian Basin, Bakken and Niobrara plays.

Overall, the Lower 48 region represents the company's largest business segment producing 491 Mboe/d in 2013 from 2.2 Bboe in proved reserves, according to the company's Lower 48 fact sheet.

It planned to spend 45% of its 2014 capital budget on unconventional liquids in the Lower 48 states.

One of thousands of pumpjacks active in the Williston Basin pulls oil from the Bakken and Three Forks formations. *(Photo courtesy of ConocoPhillips Inc.)*

Bakken

The Bakken Shale produced 27 Mbbl/d of oil for the company in 2013 along with 2 Mbbl/d of NGL and 25 MMcf/d of natural gas, or 33 Mboe/d.

ConocoPhillips holds 620,000 net acres with a 45% working interest in the play, including 430,000 net mineral acres and 190,000 net leasehold acres. Its EUR from the play totals 600 MMboe from 1,800 identified gross drilling locations.

Its gross production more than doubled during 2013, even as completed well costs dropped by 15%.

On June 30, 2014, the company had 10 operated rigs at work and planned to drill 110 new wells during 2014.

It invested about $1 billion in the play in 2014 and plans a compound annual growth rate of 20% from 2013 to 2017, from about 30 Mboe/d to about 70 Mboe/d.

According to a November 2014 presentation, its best acreage for both the Bakken and Three Forks formations lies along the Nesson Anticline, followed by the Parshall-Sanish area and the Fort Berthold Reservation. It's the second highest producer on the Nesson Anticline with some 18 Mboe/d of output.

Niobrara

In its fact sheet, ConocoPhillips lists the Niobrara in its “other Rockies” category, a division that produced 3 Mboe/d in 2013.

It leases 130,000 net acres of land in Adams, Arapahoe, Douglas and Elbert counties in Colorado’s southern Denver-Julesburg (DJ) Basin and drilled 13 horizontal producers and one vertical monitoring well to the Niobrara Formation during 2013. It called the initial results “encouraging” enough that it continues appraisal work and extended production testing to determine field potential.

ConocoPhillips is operating one rig in the Niobrara. That rig was drilling northeast of the town of Kiowa, Colo., in late November 2014. Part of the drilling already completed lies on the old Lowry Bombing Range east of Denver and even within the Aurora city limits.

The company acquired 46,000 net acres of its DJ Basin land from Lario Oil & Gas in 2011.

Continental Resources Inc.

- **Top 10 independent U.S. oil producer**
- **Largest leaseholder in the Bakken**

Continental Resources Inc., the Bakken powerhouse, downplays its Niobrara assets as it concentrates on the Williston Basin and Oklahoma.

The Bakken/Three Forks play occupies its Williston Basin activity, while the company opens the Stack, northwest Cana Woodford and South Central Oklahoma Oil Province.

At the same time, the company has sold its most significant holdings in the Niobrara play.

Bakken

Continental held more than 1.14 million net acres of land in the Bakken play, most of which was in North Dakota, at year-end 2012, according to the company’s website.

It was the first to complete a paired middle Bakken/Three Forks well, a horizontal Three Forks well and a 1,280-ft-spaced lateral with a multistage fracture treatment.

In its third-quarter 2014 report to shareholders, Continental said it produced 106.2 Mboe/d from the Bakken, up from 94.7 Mboe/d in second-quarter 2014 and 81.5 Mboe/d in third-quarter 2013 in North Dakota. It produced another 15.4 Mboe/d in third-quarter 2014 in Montana, up from 13.9 Mboe/d the previous quarter and a gain from about 13 Mboe/d in the quarter a year earlier.

The company completed 256 gross (77 net) Bakken wells in third-quarter 2014.

As it drilled wells, it also tested techniques to improve results from those wells. It tested enhanced completion technologies and monitored output to find the best completions. Its own research and industry experience showed it could extend early production rates in some areas of Bakken production and increase EURs per well. Uplift increased by 45% during the first 90 days online, and average EUR rose about 30%. It now expects EUR of some 800 Mboe per well from Bakken wells drilled in 2015. At the same time, it expects to drop well costs to $9.6 million from a previous level of $10 million.

In a November 2014 presentation, Continental said it planned to operate 19 rigs in the play in 2015 and drill 282 gross (174 net) Bakken wells. A month later, it raised its nonacquisition budget and said it planned 188 wells in the Bakken/Three Forks. By year-end 2014, in the face of falling oil prices, it cut its planned rig count in the Bakken for all of 2015 to 11.

The company’s wells give it a 40% rate of return at an oil price of $80/bbl and a gas price of $3.50/Mcf and with a return of nearly 70% with $100 oil. The company’s property holds an estimated resource potential of 4.1 Bboe with decades of drilling inventory.

It drills 2-mile laterals in its wells.

Niobrara

In 2012, Continental had accumulated 92,842 net acres in the Niobrara play in the Denver-Julesburg Basin with about 25,000 acres in the oil fairway.

Later, Pacific Energy Development (PEDEVCO) entered a definitive agreement to acquire an interest in 40 wells and 28,727 net acres from Continental for $30 million. That included 28,241 net acres in Weld County, Colo., and another 486 net acres in Morgan County, Colo. It had 11 operated and 14 nonoperated wells, and PEDEVCO was to get an after-payout interest in another 15 wells.

The 25 producing wells gave up a net 400 boe/d in September 2013.

A November 2013 report by Continental said it was divesting two lease packages in Laramie, Goshen and Platte counties in the Wyoming sector of the Denver-Julesburg Basin. Those properties included 12,448.9 net acres in Laramie County, 20,280.02 net acres in Goshen County and 413.02 net acres in Platte County.

In a late 2014 update, the company assigned no drilling rigs to its Niobrara properties.

EE3 LLC

- **Working off the beaten path**
- **Drilled successful wells**

EE3 LLC, with a history of successful operations and lucrative property sales, settled in on the North Park Basin of Colorado to look for Niobrara oil.

It is the successor to Ellora Energy Inc., which sold its 850,000 net acres of land in the Hugoton Basin to Occidental Petroleum for almost $250 million and sold the rest of the company to Exxon Mobil for almost $750 million in 2011.

Niobrara

The company has purchased property and started drilling in Jackson County, Colo., in the North Park Basin, west of the Niobrara fairway in Colorado and southwest of the Niobrara play in Wyoming. The property lies between the Laramie/Medicine Bow Range and the Front Range on the east and the Peak Range on the west.

It bought about 100,000 acres of land in the basin with seven horizontal and two vertical wells in 2013 and plans to increase production.

The Hebron #3-12H horizontal well produced about 1.1 Mbbl of oil on a 24-hour test, and its Damfino #02-06H tested for 685 bbl/d of oil during its first 30 days online with a peak production of more than 1 Mbbl/d of oil from the Niobrara Formation.

It drilled that well to 7,205 vertical ft with a 3,330-ft lateral to the Niobrara D bench and completed it with an 18-stage plug-and-perf treatment with 3.7 MMlb of sand.

Encana Corp.

- **Works a triple play in the DJ Basin**
- **Planned 55 to 65 wells in 2014**

Encana Corp. captured a sizable parcel of land in the Wattenberg Field, by far the most prolific producing area in the Denver-Julesburg (DJ) Basin and a position that gives it triple production potential from the J Sand, Codell and Niobrara formations.

Niobrara

Encana likes the northeastern Colorado play. It has been an important oil and gas producing area for more than 30 years. That means it has plenty of distribution infrastructure and no constraints to product movement. It also has significant scale, enough for a large company to work profitably, and the basin produces light oil and condensate that yield high returns.

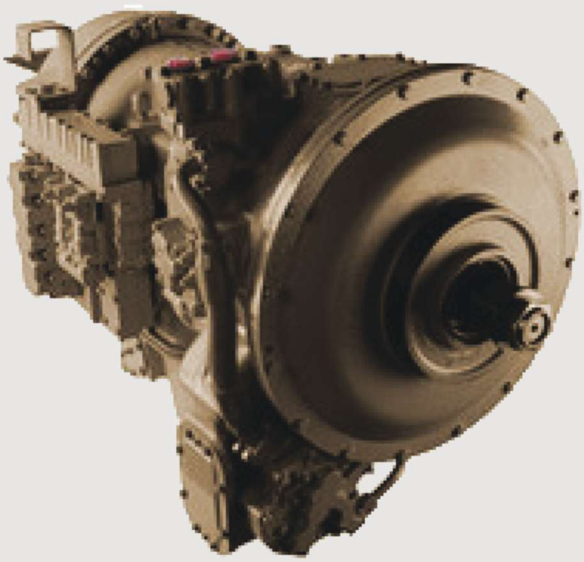
By high returns, it means 55% to 85%. It can generate a 9% rate of return even if oil prices drop to the $35/bbl to $45/bbl range.

Encana has 49,000 net acres in the Wattenberg Field with a 50% average working interest, and it expects between 325 Mboe and 550 Mboe in estimated ultimate production per well. It has an inventory of 600 to 1,000 gross well locations that it can drill for $4.5 million to $5 million.

Its fiscal 2014 production consisted of 7,500 bbl/d to 8,000 bbl/d of condensate and oil, 3,500 bbl/d to 4,000 bbl/d of NGL and 40 MMcf/d to 50 MMcf/d of natural gas.

Like other companies in the area, Encana targets oil and liquids-rich gas.

Its company target for viable plays requires a 20% compound annual growth rate through 2014



and about 75% of 2015 fiscal year upstream cash flow from liquids. The Codell/Niobrara will help it meet those requirements.

In fact, the Denver Basin is beating its expectations with year-to-date (to November 2014) drilling cycle times averaging three days faster than the company expected.

Its section-length lateral wells average less than 10 days from spud to rig release, and its one-and-a-half-section laterals take only 13 days from spud to release of the drilling rig.

By November 2014, it had successfully drilled its eighth 10,000-ft lateral well, according to a November 2014 presentation.

With a target of 55 to 65 wells for the year, it had drilled 49 net wells by the end of September 2014 with six rigs working the play.

It drilled its best well in 17 days, and it continued to lower capital and operating costs.

Encana devoted 85% of its $2.5 billion to $2.6 billion capital budget for 2014 to growth assets, primarily unconventional liquids plays. It directed the biggest chunk of that budget to the Montney play in Canada, but the DJ Basin, San Juan Basin, Eagle Ford and Duvernay plays get about equal shares in second place. For DJ Basin operations, that's $270 million to $300 million.

EOG Resources Corp.

- **High-rate driller in the U.S. and Canada**
- **High-rank producer in the Bakken, Niobrara**

EOG Resources Corp. takes pride in growing through the drillbit, and its operations in the Williston and Denver-Julesburg (DJ) basins give the company the opportunity to make that strategy pay off for its shareholders.

According to the company's website, EOG focused on onshore organic production growth in North America for 2014 on its own and with partner companies. It will acquire properties, but the acquisitions normally are around its existing operations.

Organic activity gave EOG an estimated crude oil production growth rate of more than 31% in 2014 and a 36% three-year compound annual growth rate, according to a November 2014 presentation.

Bakken

The company's drillbit growth philosophy made it one of 2013's top oil producers in North Dakota.

EOG counts the Bakken/Three Forks among its top plays, along with the Eagle Ford, Delaware Wolfcamp oil, Second Bone Spring and Leonard. All three give the company an after-tax rate of return of more than 100% with oil at $80/bbl and more than a 10% rate of return with oil priced at $40/bbl.

The company has an eight-year inventory with 640 drilling locations in the Bakken/Three Forks play. Its primary locations are split with 90,000 net acres in the core area and 20,000 in the Antelope extension to the southwest, but both returned at least 100% after taxes in 2014.

It might generate more locations. It had encouraging results with 700-ft spacing in the core area, and it's testing 500-ft and 300-ft spacing.

In addition, its operations give it strong results from all three Three Forks benches in the Antelope area. The company's Mandaree 17-05H well tested for 1.7 Mboe/d with a 3,855-ft lateral in the first Three Forks bench.

It planned to drill 80 net wells in 2014 using six rigs in the core and Antelope areas.

EOG has other properties in the Bakken Lite area north of the core and in State Line, straddling the Montana-North Dakota border. It also has properties in the Elm Coulee Field and the Bakken subcrop in Montana.

As the company drills, it improves operations. Spud-to-total-depth times dropped to 12.5 days currently from 22.7 days in 2012. In the same period, a horizontal well with a 10,000-ft lateral dropped in cost from $10.5 million to $8.7 million.

Codell/Niobrara

If the Bakken/Three Forks occupies a place in EOG's top tier of plays, the Codell in the northern sector of the DJ Basin in Wyoming ranked in the second tier. The second tier offers an after-tax rate of return of 60% with $80/bbl oil and a 10% rate of return with $45/bbl oil. That puts it on par with the

Parkman and Turner formations in the Powder River Basin and the Delaware Basin Wolfcamp combo fairway.

The Niobrara in the DJ Basin lands in the third tier with the Midland Basin Wolfcamp. Those formations give the company a 30% after-tax rate of return with $80/bbl oil and a 10% rate of return with $50/bbl oil.

Overall, EOG has 460 locations, or a 12-year inventory in the DJ Basin.

It has 85,000 net acres and 225 locations in the Codell play in Wyoming with estimated potential reserves of 125 MMboe with a 78% oil cut. Returns can reach more than 100%.

It holds another 50,000 net acres in the Niobrara with 235 locations and potential reserves of 85 MMboe with a 71% oil cut. After-tax returns are expected to exceed 45%.

It planned 39 wells to the two formations during 2014, and it's experimenting with larger fracture designs to improve production. It currently drills wells with 9,400-ft laterals.

Exxon Mobil Corp./XTO Energy Inc.

- **XTO holds the largest U.S. gas reserves**
- **Growing 38% a year in the Bakken/Three Forks**

Exxon Mobil Corp. and its XTO Energy Inc. unconventional oil and gas subsidiary tune technology to profits in the Bakken/Three Forks play in the Williston Basin.

Bakken

The world's largest public oil company and its subsidiary continue their focus on the Bakken play in North Dakota and Montana as they optimize completions and cut costs by using pad development.

The companies signed an exchange agreement in September 2012 that gave them all of Denbury Resources' 196,000 net acres in Montana and North Dakota. At that time, they expected 15 Mboe/d in second-half 2012.

That agreement increased their holdings in the basin to almost 600,000 net acres.

By February 2014, Exxon Mobil still held 531,000 net acres in the Bakken/Three Forks in North Dakota with production at 44.5 Mbbl/d of oil and 46 Mcf/d.

The company planned to run 12 to 15 rigs during 2014 in the eight counties in which it holds leases.

It held another 314,000 net acres in Montana with production at 5.8 Mbbl/d of oil and 5 Mcf/d of gas. It planned to run one rig in the two counties in which it holds leases in that state.

Fidelity Exploration & Production Co.

- **Expanding key positions**
- **Leveraging horizontal completions in the Bakken**

Fidelity Exploration & Production Co., a subsidiary of MDU Resources Group, holds properties in Texas, Louisiana, Utah, Wyoming, Montana and North Dakota with a heavy concentration on its Bakken and Three Forks properties in the Williston Basin.

Bakken

In a March 2014 presentation, the company said it held 108,500 net acres in the play and produced 1.4 MMboe in first-half 2014, which amounted to 52% of total company production.

It planned to spend $130 million in the play in 2014 with one rig drilling Bakken and Three Forks wells in Mountrail County and another drilling Three Forks wells in Stark County, both in North Dakota.

Among recent wells at that time, its Barnhart 1 20-17H in Stark County came in with IP of 1.1 Mboe/d from the Three Forks, and its Minot State Middle Bakken well tested for about 1.4 Mboe/d.

A report from MDU in July 2014 said Fidelity signed an agreement to sell 4,353 net acres of leases in Mountrail County for $200 million. The property was producing 2 Mboe/d from 81 gross wells, 49 of which were operated by Fidelity.

Fidelity retained some 12,000 net acres in Mountrail County.

The company also held property prospective for Niobrara production in southeastern Wyoming.

Hess Corp.

- **Driven by long-lived, high-margin plays**
- **First driller into the Bakken**

Hess Corp. chose the Bakken Shale in North Dakota and the Utica Shale in Ohio for the strategic investments to meet its long-term goals.

It calls the Bakken "the premier shale oil play in the United States."

Bakken

Hess Corp. not only drilled the first economic well in the Williston Basin in 1951, but it drilled the first well to the Bakken and named the formation.

In 2014, it held some 640,000 net acres in the formation, including 550,000 net acres in the core area. Some 60% of its acreage also is prospective for Three Forks production. That acreage gives the company about 4,000 drilling locations with successful downspacing. By November 2014, it had 850 producing wells online.

Its properties lie in the Tioga, Minot, Keene, Killdeer and Fryburg areas of North Dakota, and its operations make it one of the top oil and gas producers in the state.

The Bakken helped it increase its overall five-year compound annual production growth rate forecast to 6% to 10% between 2013 and 2018. It predicts overall recovery of more than 1.4 Bboe.

By 2020, it plans to increase peak Bakken production by 17% to 175 Mboe/d with the help of the successful downspacing program of 2014. The company should be able to maintain that production rate for the following four years.

Hess detailed its Bakken operations in a November 2014 presentation to investors. It reduced drilling cycle times by more than 30%, drilling costs by more than 25%, completions costs by more than 50% and facilities pad costs by more than 10%.

A lean-manufacturing program drives low-cost wells, while a data- and technology-driven system gives it productivity in the top 25% of the industry.

Ethane extraction and flexibility in oil delivery options improve netbacks.

Hess will drill 80% of its new wells in the core of the basin to 2020.

It has partnered with Baker Hughes to take advantage of technology advances such as sliding-sleeve completions.

It is conducting research and trials to drill wells with more than 50 fracture stages.

The company operated 14 rigs in 2013 and raised that number to 17 in 2014, but planned to cut its rig count to an average 9.5 in 2015 as oil prices dropped, according to a January 2015 press release. It reduced Bakken spending by $400 million to $1.8 billion for 2015. The company said it would increase activity as prices improved.

Lilis Energy Inc.

- **Pure Denver Basin play**
- **Targeting conventional and unconventional resources**

Lilis Energy Inc. properties are spread throughout the Denver-Julesburg Basin in northeastern Colorado, southeastern Wyoming and southwestern Nebraska.

Operated production comes from the J Sand, while nonoperated production comes from horizontal Niobrara wells.

Niobrara

The company has identified drilling locations for possible operations in the Niobrara Shale, Codell Sand, Greenhorn Lime, and Permian Admire and Pennsylvanian Des Moines formations in its unconventional portfolio and the J and Wykert sands in its conventional inventory.

The Codell provides multilateral upside potential with Niobrara drilling, and a standalone Codell play is emerging near the company's leases in Goshen County, Wyo.

The company's 123,000 gross (107,000 net) acres of leases lie in Banner, Kimball and Scotts Bluff counties in Nebraska; Carbon, Goshen, Laramie and Platte counties in Wyoming; and in Adams, Arapahoe, Washington and Weld counties in Colorado.

Its 2014 to 2015 programs include 18 horizontal wells aimed at the Niobrara and Codell formations in the greater Wattenberg Field area.

Three horizontal wells had been drilled with company participation through May 2014.

Marathon Oil Corp.

- **Targeting strong production growth**
- **Bakken is a centerpiece**

Marathon Oil Corp. chooses several plays worldwide in search of its growth goals, and the Bakken Shale in North Dakota is one of the plays that fits its requirements.

Overall, Marathon grew production 43% from third-quarter 2013 to the same quarter in 2014, and the quarter in 2014 was 13% higher than the second quarter.

Among plays competing for the company's investment dollars are the Eagle Ford and Austin Chalk in South Texas.

Bakken

Marathon calls its Bakken Shale properties in North Dakota "a centerpiece of our unconventional resources portfolio and a top investment priority for Marathon Oil."

The company leases some 370,000 net acres of land in North Dakota and eastern Montana with an average 89% working interest in company-operated properties.

It uses automated rigs to enhance drilling performance. It also has reduced well costs and cycle times.

In a November 2014 presentation, Marathon said it produced 56 net Mboe/d in the third quarter, a 47% improvement from the same quarter a year earlier. It hooked 19 gross operated wells to sales and brought in 16 recompletions with favorable

Pumpjacks boost production from Bakken/Three Forks wells. *(Photo courtesy of Marathon Oil Corp.)*

results in its Hector and Ajax areas. It hooked 13 of those recompletions into sales lines.

It is testing higher-density drilling with pilot programs, and three of its four planned pilots had spud by November 2014. It drilled six wells to the Middle Bakken and six additional wells to the first bench of the Three Forks.

Marathon planned a program of 55 tests on 46 wells during 2014 and early 2015, with 19 of those wells online.

It added another drilling rig as it moved into a rapid transition to higher-density pilots. It expected initial results from its four operated high-density pilot programs in first-half 2015.

Among its pilot programs, the TAT USA 34 pilot includes six Middle Bakken, six Three Forks first bench and six Three Forks second bench wells. It will spud that pilot in first-quarter 2015.

In addition, more than half of the remaining wells in its second-half 2014 drilling program area are involved in completion pilot programs with varied fluid and sand volumes.

Nine wells are being completed with reduced spacing between fracture stages, trial surfactant or plug-and-perf stage isolation techniques.

Montana Exploration Corp.

- **Canadian works Montana Bakken**
- **Looks for Bakken west of fairway**

Montana Exploration Corp., parent of Montana Land & Exploration Inc., pits its talent on recovering reserves on the Shaunavon in Canada and the Bakken in Montana.

Bakken

It holds nearly 392,000 gross acres of land, largely contiguous, around Blaine County, Mont., including land on the Fort Belknap Indian reservation. That property is located in north-central Montana and far to the west of prolific production in eastern Montana.

Montana Exploration holds the land with gas production from shallower zones.

The company estimates a potential 10 MMbbl of oil in place per section on its land. It also redrilled an early 1950s well and confirmed reservoir sand and migrated oil in the Bakken. That oil might be trapped updip from the well location.

Murex Petroleum Corp.

- **Seventeenth largest operator in North Dakota**
- **Works through affiliated companies**

The Murex Petroleum Corp. name might not be familiar, since the company works through other company names.

Its 84,000 net mineral acres are held by Linda Petroleum Co., Missiana LLC, Missilinda of Canada, Williston Projects Inc. and Mono Corp.

Bakken

The company operates 240 wells in North Dakota, South Dakota, Montana and Wyoming. Its 84,000 net mineral acres cover 55 drilling spacing units and three waterflood projects in North Dakota.

Its operations are in 13 counties in North Dakota, although the properties are operated by other companies in 11 of those counties. It also has properties in Richland County, Mont.

Niobrara

Murex operates one drilling site in Laramie County, Wyo. Although the company didn't indicate prospects at that site, other companies have produced from the Niobrara and Codell in that southeastern Wyoming county.

It also holds mineral interests in Jackson and Weld counties in Colorado. Weld County is considered prime territory for Niobrara production.

Newfield Exploration Co.

- **Rocky Mountain primary assets in Utah and North Dakota**
- **Developing the Bakken**

Newfield Exploration Co. looks to the Rocky Mountain states for oil production and dedicated 45% of its capital budget to the region.

The Rockies also provided 43% of its 2013 total domestic proved reserves and 32% of total domestic production in 2014.

Bakken

The company leases some 100,000 net acres of land in North Dakota and Montana, but it's only actively working about 41,000 net acres of Bakken/Three Forks properties in North Dakota.

With the property delineated and formations mapped, Newfield now has focused on development drilling on multiwell pads using "super-extended lateral lengths" up to 10,000 ft long.

It spent $330 million on its Bakken/Three Forks operations in 2014, and it's spending more on production efficiency. It took the company about 50 days to drill a horizontal well in the Williston Basin in 2010. It cut that number in half during the first 10 months of 2014.

It forecast 50% growth in 2014 with production from the Middle Bakken and the first bench of the Three Forks.

Its Wehrun 4H, drilled with a 9,900-ft lateral, cost the company $6.8 million to complete, including facilities. It tested for about 2.8 Mboe/d, with a 30-day IP of 878 boe/d, a 60-day IP rate of 694 boe/d and a 90-day rate of 609 boe/d.

A clean production site is the sign of an efficient operation in the Bakken oil play in North Dakota. *(Photo courtesy of Newfield Exploration Co.)*

Noble Energy Inc.

- **Top tier Niobrara producer**
- **Integrated development works**

Noble Energy Inc. came into the Denver-Julesburg (DJ) Basin early in the development of the Codell and Niobrara plays and multiplied its land position advantage with technical improvements.

It gets about one-third of total company production from the basin.

Niobrara

Noble held 610,000 net acres in the DJ Basin, including the company's largest U.S. onshore operation at the Wattenberg Field in northeastern Colorado.

The company produced 95 Mboe/d from that acreage during 2013 from 450 MMboe in net proved reserves.

According to the company's website, "Development is focused on horizontal drilling in the Niobrara and Codell formations, which produces strong returns for Noble Energy due to low operating costs and a high contribution of oil and natural gas liquids."

Those are good reasons to support the company's long-term growth plans for the basin.

Horizontal drilling, improved completion and fracturing strategies improve production and reduce drilling time.

The company also is testing lateral downspacing and increased use of extended-reach lateral wells.

Present operations focus on its Wells Ranch and East Pony properties with integrated development plans that cover everything associated with the developments from drilling through gathering. At the same time, the integrated plans minimize the surface area the company uses in one of the richest agricultural areas in the U.S.

Noble brought 167 horizontal wells online in first-half 2014 and another 86 in third-quarter 2014. It planned to drill 380 wells for the full year, according to the company's third-quarter 2014 report. At that time, it was producing more than 100 Mboe/d.

It drilled 23 standard lateral wells at Wells Ranch during the third quarter. Those wells bottomed in all three Niobrara benches. It also modified fracturing and flowback procedures for tighter fracture spacing. Currently, it drills 32 wells per section.

If its current plans hold up, Noble will bring shareholders a 23% compound annual growth rate between 2013 and 2018.

With only 16 wells per section, the company has more than 9,500 drilling locations, but 30% to 40% of its 2014 program wells tested spacing at 24 to 32 wells per section. The downspaced wells have shown production in line with wells on standard spacing.

Initial wells drilled with the plug-and-perf technique are outperforming traditional completions by more than 50%, the company said in a September 2014 presentation. It planned 20 plug-and-perf completions during 2014.

It forms partnerships with operators across the Williston Basin. Those operators drill, complete and hook up wells to production lines and turn over a share of the proceeds to Northern.

Through its contacts with landmen, Northern has been able to pick up additional parcels of nonoperated working interests from owners or leaseholders who want to cash out. It also acquires interests some operators have in other operators' wells.

In a November 2014 presentation, Northern said it held a drilling inventory of some 1,300 sites.

During third-quarter 2014, its production share averaged 16.5 Mboe/d with a 90% oil cut. It had 2,197 gross (177.5 net) producing wells and another 359 gross (25 net) wells in some stage of drilling, completion or hookup.

Its position allowed it to participate in about one-fourth of all the Bakken/Three Forks wells drilled since 2006.

Proved reserves at year-end 2013 totaled 84.2 MMboe.

Northern planned $450 million in capex for 2014.

Northern Oil & Gas Inc.

- **Pure play in the Bakken/Three Forks**
- **High profits through partners**

Northern Oil & Gas Inc. applies a different strategy from most companies. It holds a lot of land and doesn't operate any of it. The company counts on the expertise of some of the most technologically savvy companies in the industry to make its holdings pay off.

Bakken

The result of being one of the largest nonoperating participation players in the core of the Bakken/Three Forks in North Dakota and Montana is that "Northern is one of America's fastest growing oil and gas exploration and production companies," according to the company's website.

It has participated in more than 2,300 gross Bakken and Three Forks wells since 2007 and controls leases on about 186,700 net mineral acres of land, including 141,000 acres in North Dakota.

Oasis Petroleum LLC

- **Bakken returns build value**
- **Slickwater fracks increase production**

Oasis Petroleum LLC put together a large land position in the Bakken/Three Forks play in North Dakota and Montana, and it combines testing with technology to increase the value of that land and the hydrocarbons beneath the surface.

Bakken

"We believe the best way for us to generate long-term value is to grow the business by identifying, acquiring and executing large, repeatable drilling programs in known hydrocarbon-bearing areas. We call this strategy resource conversion," Oasis said on its website.

That strategy has helped the company build reserves, production and cash flow as well as a strong rate of return for stockholders.

The key to that strategy is aggressive development of its 506,900 net acres of leases in the Williston Basin.

In a November 2014 presentation, the company said it held 403 operated drilling blocks with 3,590 gross operated locations, or 17 years of inventory at current drilling rates.

It produced 45.9 Mboe/d in third-quarter 2014 and expected to produce between 47 Mboe/d and 49 Mboe/d in the last quarter of the year.

At the end of third-quarter 2014, it held 219 MMboe in proved reserves and had an average 68% working interest in its properties in North Dakota and Montana.

Its aggressive program put 13 rigs to work with three rigs dedicated to holding acreage, spacing optimization and completions.

Its well optimization program at the White Unit in North Dakota resulted in one slickwater fracture treatment in the Bakken and two slickwater wells each in the Three Forks/Sanish first, second and third benches.

It posted "strong results" from its first slickwater and density test.

Ongoing programs seek to lower costs and increase efficiency from drilling new wells to increasing performance on existing wells.

A March 2014 agreement indicates the value of the company's holdings. It sold 8,354 net acres with 2.7 Mboe/d of associated nonoperated production in and around Sanish Field for $333 million.

PDC Energy Inc.

- **Horizontal drilling sparks growth**
- **Seeking balance with oil and gas**

PDC Energy Inc. picked hot spots in its quest to balance production of oil and natural gas.

Its prime properties are the Marcellus and Utica shales in the Appalachian Basin and the Niobrara and Codell formations in the Denver-Julesburg Basin in Colorado.

Niobrara

PDC Energy Inc. seeks organic growth while maintaining a solid balance sheet and ample liquidity for operations and opportunities.

Contributors to that growth include optimized margins through efficient drilling, sound well management and environmental stewardship.

In Colorado, the platform for its operations is the liquids-rich Wattenberg Field.

"Total 2012 net production for the company consisted of 35% crude oil and NGL and 65% natural gas, most of which was derived from the Colorado region. Crude oil and NGL production rose to 53% in 2013, and the company forecasts that to rise to 60% for 2014," the company said on its website.

More than 75% of PDC's production and proved reserves in 2013 rested in its 97,000 net acres of land in the core area of the Wattenberg Field and the Codell/Niobrara play.

It drilled 70 horizontal wells to the two formations during 2013 with a 100% rate of success on wells with EURs between 285 Mboe and 500 Mboe.

Most of the company's wells were drilled with 4,000-ft to 4,500-ft horizontal laterals with 20-stage fracture treatments.

It acquired 30,000 net acres and associated production in 2012 to make it the third largest producer and leaseholder in the core area of the Wattenberg Field.

It has about 2,800 horizontal drilling locations—2,000 Niobrara and 800 Codell—based on 22 gross wells per section. Higher well densities might increase the number of locations.

It budgeted $443 million for its Wattenberg operations in 2014 with about $100 million of that going to nonoperated projects.

It added a fourth drilling rig in December 2013 and a fifth rig in June 2014 to reach its goal of drilling 123 operated wells during the year. It spud 86 gross horizontal operated wells through the end of September 2014 and participated in another 71 nonoperated horizontal wells with a goal of 84 nonoperated wells.

According to a November 2014 presentation, PDC expected to deliver returns between 30% and 75% with a New York Mercantile Exchange oil price of $80/bbl.

By the end of third-quarter 2014, it had about 2,300 net producing vertical wells and 165 operated producing horizontal wells.

Its drilling targets are the Niobrara A, B and C benches and the Codell Formation, and it has started drilling 7,000-ft extended-reach laterals.

Both the Codell and Niobrara formations offer the company a 70% internal rate of return.

PEDEVCO Corp.

- **Partnered with MIE Holdings Corp.**
- **Drilling in Wattenberg areas**

PEDEVCO Corp., also called Pacific Energy Development, started business in early 2011 and made its first Niobrara purchase in November of that year.

It aligned its potential with MIE Holdings Corp. of China and Golden Globe, a segment of a billion-dollar fund.

Niobrara

PEDEVCO holds 18,300 net acres of land in Morgan and Weld counties in the Denver-Julesburg Basin. It bought about 4,300 net acres in November 2011 and a 14,000-net-acre parcel from Continental Resources in March 2014, according to a December 2014 presentation.

The property holds 47 gross producing wells, including 15 after-payout wells. The company operates 16 gross (six net) wells in the basin and drilled five of the 16.

It drilled its first three-well pad since the Continental acquisition and began completion operations on those Wattenberg extension wells in November 2014. It holds 1,468 drilling locations at current spacing.

It plans to spend $30 million on the Wattenberg and Wattenberg extension areas in its 2015 fiscal year.

PEDEVCO estimates it can earn a 15% rate of return with a West Texas Intermediate oil price between $40/bbl and $60/bbl.

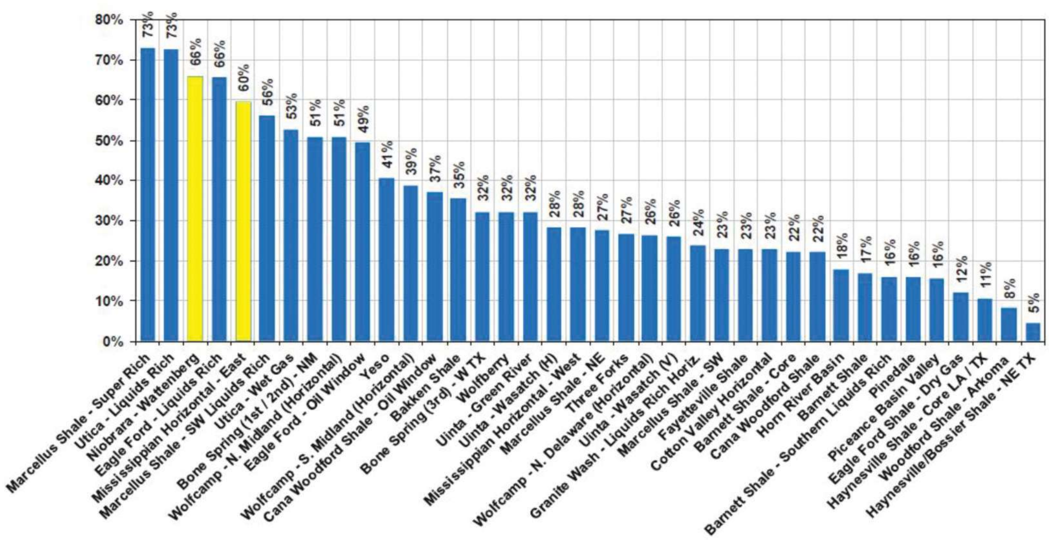
Among its assets, it holds nonoperated interests in 16 gross (two net) wells with Bill Barrett Corp., Bonanza Creek, Carrizo and Noble.

Samson Oil & Gas Ltd.

- **Australians like the Rockies**
- **Pulling profits from the Bakken and Niobrara**

Samson Oil & Gas Ltd., headquartered in Perth, Australia, and Denver, brought its quest for profits to the Williston and Denver-Julesburg (DJ) basins.

Basin Internal Rates of Return Overview



The Niobrara Shale play in the Wattenberg Field ranks high in internal rate of return at 66%, trailing only the super-rich portion of the Marcellus Shale and the liquids-rich Utica Shale. *(Source: Credit Suisse Research, October 2013, "Shale Revolution II," courtesy of PEDEVCO Corp.)*

Bakken

Samson holds a 32% average working interest in 3,303 acres adjacent to the North Stockyard oil field in the Williams County, N.D., segment of the Williston Basin with production from the Mississippian Mission Canyon (Bluell), Mississippian-Devonian Bakken and Devonian Three Forks.

The Leonard, Gene, Earl, Gary, Rodney and Everett wells, drilled to the Bakken, produced more than 761 Mbbl of oil and 953 MMcf of gas by October 2012.

The leases can support up to 12 Three Forks wells on the property as well.

The best well on the property to date was the 1-22H Gene, which tested at 2.9 Mboe/d.

Samson and its partners plan to drill out the Bakken inventory of 10 Middle Bakken, eight Three Forks first bench, six Three Forks second bench and eight Three Forks third bench wells at North Stockyard.

Samson also has a 100% working interest in its 30,000-net-acre Rainbow area near North Stockyard, where it already has the Australia II and Gretel II wells. It has a 66% working interest in subsequent wells. This also is a Bakken production area.

It plans nine Middle Bakken and six Three Forks wells on that property.

Niobrara

In December 2014, the company published an update on its Hawk Springs project in Goshen County, Wyo., a southern Wyoming county prospective for Niobrara and Codell zones.

It perforated its Bluff 1-11 well in the 9,500 Sand between 7,738 ft and 7,754 ft. The well unloaded quickly and flowed nonflammable gas at a rate of 8 MMcf/d. Samson has a 52% interest in the Bluff prospect and a 25% share of the well.

A fluid boundary shows up under analysis, and it's likely the fluid is oil rather than water. With an estimated 20 MMbbl of oil in place, a 25% recovery factor would give the company 5 MMbbl of recoverable oil.

Samson emphasized this was not a reserve estimate, and it plans another downdip appraisal well to prove reservoir continuity and fluid content.

The company holds about 20,000 leased acres in the Hawk Springs area, some with a 50% interest and others with a 100% interest.

Following a 3-D seismic survey in 2011, it developed an inventory of Niobrara, Muddy/Dakota, Sundance and Permo-Penn prospects. A Samson well resulted in the first Niobrara production from the Niobrara north of Silo Field in the DJ Basin. That well, the Defender US33 #2-29H, has produced more than 10 Mbbl of oil. The company plans further development.

Samson Resources Co.

- **Leases 2 million acres throughout the U.S.**
- **Williston offers long-lived, prolific reserves**

Samson Resources Co. picked the Williston Basin and Bakken/Three Forks combination among its high-yield basins.

Those basins include the Powder River, Greater Green River, San Juan, Anadarko, Arkoma and East Texas basins.

By year-end 2013, the company held some 1.9 Tcf of gas-equivalent reserves, and it produced about 629 MMcf/d of gas equivalent during second-quarter 2014.

Liquids and liquids-rich targets form the base of Samson's activity in the Rockies.

Williston

Samson joined the Williston Basin club of operators through a joint venture in 2005 and expanded into one of the largest leaseholders in the area.

In a third-quarter 2014 report to shareholders, the company said it was starting a data room to sell Williston Basin properties. Those properties produced 25 MMcf/d of gas equivalent in the first nine months of 2014, about the same production level as 2013.

Samson called results encouraging from its first operated four-well pad on increased spacing with plug-and-perf completions.

In a September 2014 presentation, Samson said it held 127,000 net acres of Bakken and Three Forks leases, including some 71,000 net acres in Divide County, N.D. It's running a one-rig program drilling infill wells in Ambrose Field and delivered nine gross operated wells to sales in second-quarter 2014.

Niobrara

The company's primary targets in the Powder River Basin of northeastern Wyoming are the Sussex, Shannon, Frontier, Muddy and Parkman formations. The 299,000 net acres of land also offer production potential from the Niobrara and Mowry shales.

The Powder River Basin produced 26 MMcf/d of gas equivalent for Samson in the first nine months of 2014, up from 23 MMcf/d of gas equivalent in the same period a year earlier.

During 2014, the company spent its time drilling Sussex wells with 2-mile laterals and assessing the upside potential of the Mowry and Frontier formations. It has one rig drilling to the Sussex.

SM Energy Co.

- **Holds core positions in the Eagle Ford and Bakken**
- **Adding assets in the Bakken/Three Forks**

SM Energy Co. directed the kind of investment to its Bakken/Three Forks properties in North Dakota and Montana that allowed it to post an impressive growth rate, and it planned to ramp up activity to an even higher level.

Bakken

SM Energy held 110,000 net acres of land at its Gooseneck properties, including 12,500 net acres added in October 2014. It leased another 42,000 net acres in its Raven/Bear Den area.

It brought in nine gross flowing completions during third-quarter 2014, according to a presentation for the quarter.

In a September 2014 presentation, the company said it put together a 77% compound annual growth rate in the Bakken since 2010 and had 55.8 MMboe in reserves at year-end 2013.

The company's active properties are in Divide and McKenzie counties in North Dakota, but it also has properties with Bakken/Three Forks potential in Montana.

The company had two rigs working the Raven/Bear Den area in second-quarter 2014 and another rig operating in Gooseneck.

SM Energy said it planned to increase activity in fourth-quarter 2014 and in 2015.

Southwestern Energy Co.

- **Nation's fourth largest gas producer**
- **Working off the beaten Niobrara path**

Southwestern Energy Co., the company that started the Fayetteville Shale play in the Arkoma Basin in Arkansas, still seeks oilpatch profits where most other companies aren't looking.

That strategy helped make it one of the biggest gas producers in the U.S. behind Exxon Mobil, Chesapeake and Anadarko Petroleum.

The 40-year-old company prides itself on being an explorer as well as a producer. On the production side, its assets include a dominant position in the Fayetteville Shale and properties in the Marcellus Shale play in Pennsylvania.

Now Southwestern Energy has turned its attention to the Niobrara Shale.

Niobrara

The Niobrara Shale weighs in on the company's exploration side, which it calls new ventures. It has acquired or leased 380,000 net acres on land in the Sand Wash Basin of northwestern Colorado that is prospective for the Niobrara Shale.

It is testing that acreage with three vertical wells drilled by the end of third-quarter 2014. At that time, it was drilling a horizontal well and planned another vertical well in the area by year-end 2014.

The company also holds 302,000 net acres of land in the Denver-Julesburg Basin with a total land cost of about $172 per acre. That property is northeast of the main Niobrara fairway, and the company is looking for Pennsylvanian-age hydrocarbons.

The area has produced from vertical wells since the 1920s with an average 130 Mboe per well of ultimate recovery.

The company has focused on volatile oil and condensate.

Statoil ASA

- **Operates in more than 30 nations**
- **Bought a big position in the Bakken**

Norway's Statoil ASA chooses the plays it likes from a worldwide list of the most profitable nations and the most profitable producing formations.

Among those choices are some of the best shale plays in the U.S.

Bakken

In a November 2014 presentation, Statoil said it became an operator in the Bakken/Three Forks play in late 2011 with the purchase of Brigham Energy and that company's 275,000 net acres of land. The leases were producing 55 Mboe/d.

With the help of Brigham's veterans, led by the Statoil corporate culture, it became a leader in reducing flaring from Bakken/Three Forks wells.

In a May 2014 release, Statoil said it successfully tested a pilot well stimulation using 100% returned water on two wells in Williams County, N.D. At that time, it was the only company using returned water for stimulation.

Torstein Hole, senior vice president of U.S. onshore development and production North America, said, "If this pilot proves successful overall after total analysis, we could have an opportunity to significantly reduce our environmental footprint and still maintain efficiency.

"Continuously improving our operational practices is imperative to our overall onshore success—and technology plays an important role here."

Three drilling rigs temporarily dot the landscape during prime drilling time for the Bakken/Three Forks play. *(Photo by Ole Jørgen Bratland, courtesy of Statoil)*

In this case, the company wanted to reduce the amount of freshwater it used in developing shale resources, sometimes as much as 4 MMgal per well, in a traditional fracture treatment.

Research helped industry experts create the viscosity the company needed to carry proppant with only simple filtration at the well site. The purified return water eliminated the need for imported freshwater in the Statoil pilot program.

It increased drilling and completion spending to hone techniques that increase recovery. Specifically, it planned to increase drilling and completion spending by 10% for a 25% gain in recovery in 2015.

Among those techniques, the company is using slickwater completions to double the flow rate and gain three to four times the liquids volume as earlier completions. At the same time, it uses about the same amount of proppant.

Its results have ranged from better to significantly better in most producing areas, according to the company.

Next, it will test higher proppant levels in its completions to further improve results.

Helge Lund, Statoil president and CEO, added, "Entering the Bakken and Three Forks tight oil plays and taking on operatorship represents a new significant step for Statoil. We are positioning ourselves as a leading player in the fast-growing U.S. onshore oil and gas industry in line with the strategic direction we have set out."

The company estimated its risked resource base in the Williston Basin at 300 MMboe to 500 MMboe. In late 2014, it produced a net 21 Mboe/d and estimated its property had the potential to produce between 80 Mboe/d and 100 Mboe/d at some point in the next five years.

Stetson Oil & Gas Ltd.

- **Seeking long-term production**
- **Starting work in the Bakken**

Stetson Oil & Gas Ltd., led by an executive team with international experience, would like to develop large oil and gas reserves.

With that goal, it was natural for the company to step into the Williston Basin and the Bakken/Three Forks play.

Bakken

The company teamed up with a joint venture partner to drill the initial commitment well on land leased from the Tribal Council of the Three Affiliated Tribes of the Fort Berthold Reservation in North Dakota.

Under the agreement, Stetson was carried on all well costs through the recompletion and abandonment of the existing well.

Stetson had a 40% working interest in the acreage.

The company has a $75,000 letter of credit for its activity on the Fort Berthold Reservation land. That letter was secured by cash on hand in September 2014, but the company planned to cancel and return the letter once the well is abandoned, the site is reclaimed and the leases have expired.

Synergy Resources Corp.

- **Veteran DJ Basin operator**
- **Working aggressive drilling campaign**

Synergy Resources Corp. started operations in northeastern Colorado 31 years ago, assembled a large acreage position in Colorado and Nebraska, and mounted a drilling program in the core of the Wattenberg Field.

Niobrara

Synergy put together 25,765 net acres in the northeast Wattenberg extension, 30,859 net acres in the Wattenberg Field and 182,680 net acres in the Nebraska portion of the Denver-Julesburg (DJ) Basin. The company also has 64,119 net acres of land in northeastern Colorado with proven shallow gas production from the Niobrara.

It has 284 net producing wells and operates 300 wells. It has drilled 168 wells since 2009.

More than 99% of its production to date has come from the core Wattenberg Field area where it produces 83% oil and 6% NGL.

Among reasons to operate in the DJ Basin, the company listed:

- Low drilling and completion costs;
- Rapid return on investment;
- High level of predictability;
- High drilling success rate;
- Rich drilling opportunities, including the Codell and Niobrara;
- Long-lived production with a reserve life of more than 30 years;
- Liquids-rich gas; and
- Abundant takeaway capacity.

Synergy limits its risk by drilling in proven areas, with no dry holes on its record to date. It started drilling horizontal wells in May 2013 and started producing from five horizontal wells on its Renfroe Pad in September 2013. By September 2014, it added 28 more operated horizontal wells and participated as a working interest owner in more than 70 additional horizontal wells in the Wattenberg Field.

The company still is adding to its land position. In December 2014, it bought 5,040 gross (4,053 net) acres of land with Codell and Niobrara potential for $125 million. That property includes a nonoperated interest in 17 horizontal wells with daily production of 1.24 Mboe/d, 73 operated and 11 nonoperated vertical wells. It also has 91 net horizontal locations.

The property also includes 2,400 gross (1,739 net) acres with rights for the Sussex, Shannon and J-Sand formations.

The acquisition will give Synergy more than 35,000 net acres in the Greater Wattenberg area.

Synergy plans to spend between $325 million and $350 million in its 2015 fiscal year, including the $125 million acquisition.

Overall, Synergy can drill a potential 932 wells in the core Wattenberg area and another 805 wells in the northeast Wattenberg extension.

It added a third horizontal drilling rig to its program in September 2014.

By November 2014, it had completed 39 horizontal wells on seven drilling pads and was drilling three additional pads. It planned to add 35 wells during the following five months.

Its northern Colorado properties are covered under a 20,000-acre exploration agreement with Vecta Oil and Gas Ltd. That land is prospective for the Niobrara Shale, Greenhorn Lime, D-Sand and J-Sand. Synergy is the operator of the program.

Pending acquisition of 4,053 net acres will bring the core Wattenberg leases to nearly 35,000.

There are 932 potential wells in the core Wattenberg and 805 in the northeast extension.

The company added a third horizontal rig to the core in September 2014, up from one rig a year earlier. It also completed 39 horizontal wells in seven pads with a 100% success rate. The company is drilling three additional pads.

Tracker Resource Development III LLC

- **Working develop-and-sell program**
- **Makes uneconomic properties profitable**

Tracker Resource Development III LLC is the latest entity of a private company that finds oil and gas prospects with significant resource potential and low recoveries, analyzes those properties and turns them into repeatable resource development plays.

That technique has worked successfully in Texas, the Midcontinent and Rocky Mountains, and the company is actively seeking additional projects.

It likes large-scale projects, particularly resource plays that respond to fracturing techniques.

The original company was formed in 2004, and the current entity has a commitment of $400 million from EnCap Investments and ZBI Ventures LLC.

Bakken

A previous entity of the company, Tracker Resources Development II LLC, found 440 MMboe in net recoverable reserves in the Williston Basin after drilling 53 horizontal wells with more than 90 miles of lateral length and optimizing multistage completions in those wells.

It sold the properties in 2010 to Hess Corp. for $1.1 billion.

It partners with Red Arrow Energy, another company in the EnCap portfolio, on that venture and formed TRZ Energy.

Triangle Petroleum Corp.

- Focused on the Williston Basin
- Fast-tracking the Bakken/Three Forks

Triangle Petroleum Corp., with four rigs running in its core area in North Dakota, parlayed its Bakken/Three Forks holding into a growth rate of more than 100%, and it's still running strong.

Bakken

The company holds 135,000 net acres of land in the Bakken/Three Forks play in North Dakota and Montana with some 51.7 MMboe in proved reserves.

In the second quarter of its 2015 fiscal year—ending July 31, 2014—production increased by 146% to about 13 Mboe/d, from the same quarter a year earlier. At the same time, proved reserves rose by 134%.

The company is trying to increase its position in the play with bolt-on acquisitions and trades in its core area, according to an October 2014 presentation.

It claimed 103 gross operated horizontal wells on production in October 2014 with another seven wells awaiting completion. Some 90% of its operated producing wells were hooked up to gas sales at the end of its first-quarter fiscal year. It had no operated wells producing to gas lines a year earlier.

Testing showed potential for downspacing on the company's wells, and nearby operators also successfully tested tighter spacing in both Bakken and Three Forks zones.

It has 577 remaining operated horizontal drilling locations.

Its core area covers some 93,000 net acres, mostly in McKenzie and Williams counties in North Dakota, where its properties are 56% operated. Most of its drilling capital is directed to the Rough Rider areas in the two North Dakota counties.

At the end of July 2014, it produced 10.55 Mboe/d from its North Dakota properties.

It held another 42,000 net acres of Bakken/Three Forks land in Roosevelt and Sheridan counties on the northwestern flank of the Williston Basin in Montana, adjacent to the Elm Coulee Field.

Most of that area is undeveloped.

Triangle plans three or four exploratory wells on that property during its 2015 fiscal year.

Ursa Resources II LLC

- **Experienced in shale operations**
- **Checking Niobrara potential in Colorado**

Ursa Resources II LLC has operated properties onshore throughout the U.S. and is familiar with operations along the Gulf Coast of Texas, in the Permian Basin in Texas and New Mexico, in the Arkoma Basin in Arkansas, and in the Williston Basin in North Dakota and Montana.

Its management has experience in unconventional reservoir development in the Fayetteville Shale and Bakken Shale.

Niobrara

The company held 260 producing wells on 60,000 net acres of land in Garfield County, Colo., a segment of the Piceance Basin.

Its current primary target is condensate from the Williams Fork (Mesa Verde) reservoir. Secondary targets include the Mancos/Niobrara. WPX Energy recently completed high-volume wells from the Niobrara in the area.

U.S. Energy Corp.

- **Joins ventures with proven operators**
- **Bakken/Three Forks pays off**

U.S. Energy Corp. takes a working interest role in conventional plays as well as select operations onshore along the Gulf of Mexico, in the Eagle Ford Shale and in the Bakken/Three Forks play in North Dakota and Montana.

It has taken part in Williston Basin operations since 2009.

Bakken

The company signed a drilling participation agreement in 2009 with a subsidiary of Brigham Exploration Co. to jointly explore on 19,200 gross acres in Brigham's Rough Rider prospect in Williams and McKenzie counties in North Dakota. Its early working interest shares in 15 units in the project area by participating in one initial well in each unit. That gave it rights to drill up to 30 gross wells each in the Bakken and Three Forks Formation. That number could double if downspacing is allowed.

In 2011, U.S. Energy sold 75% of its interest in undeveloped acreage at Rough Rider to Brigham and kept 25%.

The company also bought 35% of Zavanna LLC's interest in 6,500 net acres in McKenzie County for about $10.99 million in December 2010. It sold 75% of two prospects in that acreage to GeoResources Inc. and Yuma Exploration and Production Co. for $16.7 million.

U.S. Energy also participated in two wells operated by Murex Petroleum Corp.

Overall, the company participated in some 74,280 gross (2,939 net) acres of leases in Williams, McKenzie and Mountrail counties in North Dakota. It had participated in 94 gross (10.18 net) wells by the end of September 2014 and had produced about 666 net boe/d.

Through October 2014, it participated in eight Bakken and Three Forks wells with working interests of less than 1%.

Whiting Petroleum Corp.

- **Second largest oil producer in North Dakota**
- **Large presence in the Niobrara**

Whiting Petroleum Corp. got into the Bakken/Three Forks and Niobrara oil plays early in their development, obtained prime properties and executed profitable development plans in both areas.

In addition, the company has one of the largest EOR projects in the nation at North Ward Estes Field in the Permian Basin in Texas.

All three projects contribute to the company's goal of sustainable growth.

Bakken

In addition to its already commanding land and production position in North Dakota, Whiting completed the acquisition of Kodiak Oil & Gas Corp. in late 2014 for some $6 billion.

That acquisition raises the company's lease position to 855,000 net acres and gave the combined company an estimated 2014 production of 152 Mboe/d.

Whiting at first estimated its combined Whiting-Kodiak reserves at 606 MMboe. It later put out a revised estimate of 780 MMboe, based on analysis by independent engineers.

Even without the Kodiak acquisition, Whiting posted record Bakken/Three Forks production of about 87.5 Mboe/d in third-quarter 2014, for a 33% increase from the same quarter in 2013.

Among significant wells, its Brehm 13-7H in Sanish Field tested for an IP rate of about 3.8 Mboe/d in August 2014. The Pronghorn Federal 44-11PH tested at about 3 Mboe/d in July, and the Sundheim 21-027-1H well in Missouri Breaks Field logged a 64% greater 200-day cumulative production than an offset well, which was completed with older technology.

The Flatland Federal 11-4HR tested for 7.1 Mboe/d from the Middle Bakken, the Flatland Federal 11-4TFH for 7.8 Mboe/d from the Upper Three Forks and the Flatland Federal 11-4 TFHU for 5.9 Mboe/d from the Lower Three Forks, all in October 2014 and all from the company's Tarpon Pad.

Whiting holds 174,398 gross (82,517 net) acres of Bakken and Three Forks land in Sanish Field; 170,000 gross (118,784 net) acres of Three Forks land in Lewis and Clark Field; 61,337 gross (38,029 net) acres of Middle Bakken/Three Forks leases in Hidden Bench Field; 8,845 gross (6,298 net) acres in the Starbuck Middle Bakken/Three Forks area; 95,769 gross (58,839 net) acres of Three Forks leases at Missouri Breaks; and 29,827 gross (13,953 net) acres of Middle Bakken properties at Cassandra.

Overall, it has more than 1.04 million gross (663,237 net) acres of land prospective for various formations in North Dakota and Montana.

Internal rates of return range from 43% to 133% from the company's Williston Basin properties with payout in 0.9 to 1.9 years.

Niobrara

Whiting put together more than 129,669 net acres of leases in the oil window of the Niobrara in Colorado. That land covers Whiting's Redtail development with production of 8.6 Mboe/d in third-quarter 2014, representing a 19% gain from the second quarter.

Its Niobrara C bench discovery, the Razor 25B-2549, tested for 712 boe/d during a 10-day period, and a Codell/Fort Hays discovery, the Razor 25B-2551, gave the company a 10-day average production rate of 570 boe/d.

One reason for the high growth rate is that Whiting holds land in the sweet spot of the play northeast of the Wattenberg Field in Weld County, Colo. That land gives it drilling targets in the Niobrara A, B and C benches and the Fort Hays/Codell combination.

At the end of third-quarter 2014, it was drilling eight wells per spacing unit to both the A and B benches. That gave the company about 5,000 potential drilling locations to only the A, B and C benches.

It has an average working interest of 72% in its Denver-Julesburg Basin leases.

The company can drill a horizontal well for $5.5 million.

The A, B and C benches of the Niobrara on the company's property contain some 70 MMboe of original oil in place.

Its Redtail Field provides a 42% internal rate of return with payout in two years at $70/bbl oil.

WPX Energy Inc.

- Most prolific gas producer in Colorado
- Taking Colorado technology to the Bakken

WPX Energy Inc. combines early acceptance of technology with resource-size land positions in important plays.

It holds a substantial land position in the Piceance Basin of northwestern Colorado where it honed efficiency into its operations. It brought those efficient operations to its properties in the Bakken play in North Dakota.

Bakken

WPX bought Dakota-3 E&P Co. LLC in December 2010 to gain access to some 84,000 net acres on rights to production on the Fort Berthold Indian Reservation.

It brought its multiwell pad drilling and completion techniques from its Piceance Basin operations to the Williston Basin and lowered costs by 10% to 20%. Current proved reserves total 105 MMboe.

One application of technology lies in the use of ceramic proppant. "We're currently using about a two-thirds to one-third ratio of ceramic to sand. Although that adds about $1 million to our costs, ceramic completions are more predictable than sand, leading to better results," the company said on its website.

It participated in 51 new oil wells in 2013 and drilled 39 gross (36 net) wells in the first nine months of 2014. It has five rigs working its acreage there.

Niobrara

The company became the largest gas producer in Colorado primarily through its development of the Williams Fork and other zones in the Piceance Basin where it has more than 4,400 active wells.

In that area, it puts its rigs on tracks to move the whole rig, which saves rig-up and rig-down time.

The company built a rig that runs entirely on natural gas. It's less expensive and lowers emissions.

Earlier, it was one of the first companies to use poly diamond crystal drillbits, which drill faster and don't break.

It can drill up to 22 wells from a pad, using 75% less land than individual drilling operations.

The company worked with Nabors Drilling to modify a rig to fit in the narrow canyons in the Piceance Basin.

Although the company's primary Piceance Basin target has been the Williams Fork, it recently completed a horizontal well to the Niobrara zone that tested for 14 MMcf/d of gas. Its second vertical well to the Niobrara tested for 2 MMcf/d of gas. ■

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Making the **Bakken** and **Niobrara Economic**

Operators turn to technology to cut costs, improve efficiencies and increase production.

By Eldon Ball
Executive Editor

With the price of oil still drifting below $50/bbl, operators in the Bakken and Niobrara are increasingly turning to operating efficiencies and technological innovation to make drilling and production operations there viable. In an intense focus on the bottom line, the mantra among operators has become "efficiency."

The drop in commodity prices is forcing operators to reexamine efficiency in drilling and completion, a recent study by Hart Energy Market Intelligence found.

"Of note, while operators discussed specific tools, the greatest contribution to better performance involves mastering the process, such as pad drilling and enhanced completions," the exclusive report stated. "Emerging technologies of note among operators include greater use of high-efficiency downhole motors for drilling and the nascent use of coiled tubing and sliding sleeves for pinpoint stage stimulation in completions. Operators report completion costs average 60% of well costs while drilling has fallen to 20% of well costs."

The report also noted that any technology that cuts cost is being incorporated into the completions phase.

"Respondents cited three key technologies across all phases," the report stated, "although these technologies are not necessarily new, including pad drilling, high-efficiency mud motors and enhanced completions. Better well planning from early seismic/geological phases through the completion stage was the main avenue toward cost savings for some respondents. In addition, respondents mentioned that renegotiating contracts and better logistical planning are shaving cost."

"Operators just don't have as much wiggle room as they used to," said David Adams, vice president of operations technology for North America at Halliburton. "For a while, there was such a manufacturing type process, and in the Niobrara many of the operators were doing what I would refer to as a cookie-cutter type of completion approach. But as oil prices come down and they look at this

GOR [gas-oil ratio] variability, they look at the faulting and the complexity of the reservoir. All of a sudden it's opened up some eyes in regard to, 'Hey, we need to tailor our treatments and designs specifically to our reservoir to ensure that we extract every bit of the hydrocarbons we possibly can out of each wellbore."

David Adams

Adams expects to see even more improvement in drilling and completion technology in the future. "I know that there are technologies out there that are yet to be determined," Adams said. "My personal opinion is that we're starting to get more customers to buy into some of these latest technologies and are beginning to implement them. As you look at the lower commodity prices today, it's so much more important to ensure that you get every barrel of oil you can out of every well at the lowest cost possible. So operators are looking for ways to lower their cost per boe [barrel of oil equivalent]. I think that today more than ever, we're seeing our customers switch to ensuring that they're extracting every bit of the hydrocarbons out of every well they drill, more so than what they would have three to six months ago."

Both the Bakken and Niobrara have seen major advances in operational efficiencies across the board, said Alfred William Eustes of the Colorado School of Mines Petroleum Engineering Department.

"It's really remarkable, in the last decade, if you look at the step changes that have been wrought and the ability for operators, service companies and contractors to reduce the time involved—and of course the associated cost involved—in creating these wellbores," Eustes said. "It's absolutely astonishing to me, the phenomena step change with some of the wells that I've seen here in the Rockies. They're talking about drilling these 9,000-ft laterals in the Niobrara in six days. It amazes me that that can be done. That's due to relentless work toward finding all the little nuances and being able to understand the process and to basically engineer out and design out all of the things that tend to bog you down."

"From an unconventional standpoint, we believe that operators were faced in 2014 with three reemerging challenges," said Nicole Braley, global strategic marketing manager at Weatherford International. "Specifically in the Bakken—the second largest in terms of investment from operators in 2014—that trend leads into one of the three challenges, which is optimizing costs. Optimizing costs goes across the board, not only investment in the acreage but optimizing drilling and completions costs as well."

The second challenge Braley said operators will focus on in 2015 is enhanced production, particularly in the Bakken with renewed focus on oil. "Over the last four years, you can look at any information or market analysis and it's just skyrocketed from 2010 to 2014 in terms of oil production. So, new technologies and techniques lead into both cost reductions and improved production," Braley said.

The third challenge Braley said operators are focused on with regard to unconventionals, particularly those resources in the Bakken, is aligning with environmental and governmental regulations. "Specifically, in 2014, operators were faced with reducing gas flaring in the Bakken play. We believe operators are going into 2015 with the viewpoint of, 'You know what, we're going to optimize costs and production with new completion techniques, multitype drilling [and] other methods as well as compliance with the gas flaring and adherence to other proven environmental factors as well.' That's sort of the general landscape, if you will."

Anadarko uses sounds walls to decrease light and noise, as part of its focus on the environment and community. *(Photo courtesy of Anadarko Petroleum)*

Anadarko Petroleum, one of the major players in the Niobrara and Codell, echoed that sentiment. Anadarko initiated a number of efficiencies during 2014 and continues to build on that strategy in 2015.

"Incorporating the efficiencies learned in the early years and working toward continuous improvement of both its horizontal drilling and completions applications has resulted in rapid growth of the Wattenberg Field," said Craig Walters, Anadarko's vice president of Wattenberg Operations.

Anadarko's Wattenberg horizontal program in northeastern Colorado targets the liquids-rich Niobrara and Codell formations at depths of about 7,000 ft, Walters said.

Anadarko estimates its Wattenberg horizontal program holds net resources of 1 Bboe to 1.5 Bboe, with additional potential through optimized spacing and recovery. Anadarko has developed a strong technical understanding of the field, Walters said, while actively listening to and engaging stakeholders. "As a result, the Wattenberg team accelerated into 2014 as one of the most active and successful programs in the U.S."

Walters said that one of the greatest challenges lies in operating in an urban environment. "As the more urban areas of the Wattenberg Field expand, our drilling and completions teams are committed to implementing leading-edge technology to minimize impacts."

Comparing the technological aspects of operation in the Niobrara with other unconventional plays, Walters said that many of the technologies in the Wattenberg Field are necessary due to the geography as well as the geology.

"Seated at the base of Colorado's Front Range, numerous geological events have broken portions of the Niobrara up into complex structures," Walters said. "This allows wellbores to penetrate multiple pay benches and encourages optimal drilling and completions designs to vary across the field."

Walters said that Anadarko has made significant investments in infrastructure in the Wattenberg, from new battery designs to increased usage of electrical equipment on its locations.

"Additionally, through Anadarko's ownership in Western Gas Partners, significant attention and alignment can be applied to full-field development. Anadarko also has implemented extensive oil pipelines to take trucks off the road and lower the cost of operating," he said. "In 2014, the partnership added significant cryogenic processing capability at the Lancaster gas plant. These and other gathering projects give Anadarko the flexibility to grow with the infrastructure without significant lag time. We called this 'loading the spring' as we built out infrastructure in the basin to support future growth. That expansion was demonstrated in 2014 with tremendous growth in the field. The program and approach was so successful that we are sharing that knowledge and replicating the approach in our Wolfcamp Shale in West Texas."

"INCORPORATING THE EFFICIENCIES learned in the early years and working toward continuous improvement of both its horizontal drilling and completions applications has resulted in rapid growth of the Wattenberg Field."

—Craig Walters, Anadarko

Enabling technology

"It's not like one huge technological change," Eustes said. "There are some things that I call enablers. You know, PDC [polycrystalline diamond compact] bits were an enabler; some of the new motors are enablers; being able to measure on the fly—MWD—is an enabler. Those kinds of things are what enable us to do this. There are also a lot of little things that go into being able to create these wellbores in such a short amount of time. And that's why I see a lot of relentless work done in the oil patch. It's to be able to continue to develop those key performance indicators, so you can track where you are and to be able to continuously solve and improve your operations.

That requires a lot of people, and it takes a lot of knowledge and a lot of data.

"What I'm seeing lately is that we're recording a lot of data from the rig—the weight, the rpm, for instance, and you would expect that," Eustes said. "And we used to collect that data, but it was not in a format that was amenable to being manipulated and understood. Today, with 1-sec data where you're recording the data every second, you're talking about terabytes of data. There's so much information in it that I think we're just now getting into understanding what is in that information stream that can help us do better.

"I would imagine that being able to send signals back to the surface so that we can think of it as seeing in real time—how much more efficient can we be? How much weight are you putting on your bit? It would be nice to know exactly what that number is. We can kind of infer that from the surface. Wouldn't it be nice to have a sensor downhole that says, 'You need to put more weight on this bit if you want this thing to go faster.' You now have Intellipipe, and other people are looking at other methodologies for getting signals back to the surface."

Eustes said there are other industries that have other methods that might be adaptable. He said better downhole sensors that enable improved knowledge of what's going on down there will be another technology enabler. "Another thing that that feeds into is drilling automation. If we've got more sensors downhole, we can do better automation and maybe drill our wells better," he said.

Drilling efficiency

Increases in drilling efficiencies are considered key to cutting costs and staying profitable in the Bakken and Niobrara plays.

Pad drilling is commonly reported as saving up to 10% of drilling costs per well, according to an exclusive Hart Energy Market Intelligence report. "High-efficiency downhole mud motors are also credited with huge reductions in drilling time required per well, saving an additional 10% to 20% of drilling costs by helping reduce the number of drilling days," the report noted. "In the completions phase, technologies currently being utilized do not necessarily add up to upfront costs savings." However, these technologies raise IP and EUR, which contribute to a lower cost per barrel of oil, according to the report.


Pat Bent

"In the last few years, we've significantly reduced the number of drilling days in all phases of the vertical, curve and lateral sections of drilling operations," said Pat Bent, vice president of drilling and completions, northern region, at Continental Resources. "That's been due to a number of improvements in operations and rig design but has focused heavily on MWD, motor and bit performance. That optimization aspect of our well construction is continuing through work with our directional service providers in improving reliability and durability of their motors and tools. There's still room to improve, and that's going to be a focus with Continental over the next 12 to 24 months. We see that as a continuing area for improvement."

Optimization of well spacing in select areas of Continental Resources' acreage is also an ongoing effort, Bent said. "Our larger pads with increased well count have introduced greater design challenges, from a subsurface perspective addressing anti-collision concerns in all segments of the well, along with density issues and surface concerns due to wellhead spacing to allow for pumping unit and surface facility configurations," he said.

"As we continue to add more wells to individual pads in an effort to minimize our environmental footprint, those issues continue to be challenging," Bent said. "We need to utilize all the technology and data we have available with respect to our well design criteria. Optimization in all aspects of development is a key opportunity for us right now."

There has been a fairly recent completion renaissance during the last 12 to 18 months in a move toward slickwater and hybrid stimulation designs, Bent said. "This is complimentary to the horizontal drilling renaissance we've been talking about for several years now. The development of the play keeps evolving. Understanding the effectiveness and efficiency from a cost and performance perspective

of both those designs will be absolutely essential in 2015 and beyond."

In today's price environment, enhanced completion designs and cost control are critical issues for all operators, Bent said.

"Drilling technology has improved dramatically," he said. "With new AC [alternating current] rigs and EDR [electronic drilling recording] capabilities that are available on the market today, the industry has the ability to script or map the drilling of the well from surface to total depth in the lateral section. Using those best management practice techniques, in combination with current state-of-the-art directional drilling technology, we can continue to become more efficient and reduce cycle time for well construction. We're also seeing increased knowledge and experience of personnel, and we have recognized that efficiency gain in overall optimization as well."

"There are three main challenges that we have in the Bakken," said Derek Allan, reservoir development services director of the western geomarket for Baker Hughes. "The first one is just quite simply about speed, getting to the pay zone as quickly, effectively and safely as possible. Then it's accessing the right pay, the sweetest part of the reservoir, to optimize production. Third, is that the Bakken is maturing. We're looking at recompleting and redeveloping existing fields to extract more of the hydrocarbons left behind by primary production.

"These three main operation developments are what we see looking to undertake the Bakken last year into this year. One example of the efficiency and effectiveness that we're looking for is our newly-developed drilling motor, [which is] a motor and bit combination. The motor is effective at getting down through overburden above the productive horizons."

"To elaborate a little bit more, the new motor technology, available in two different sizes, allows drilling to be done more quickly because of the improved performance through a stiffer motor, less vibration and higher torque output," said Bob Laing, sales director for Baker Hughes. "This allows more weight to be applied to the bit, and when combined with a Baker Hughes drillbit often [allows] the curve and lateral to be drilled in one run. Being able to do it in one run improves the economics. We also have a rotary steerable system that allows you to steer the bit while rotating the drillstring, and this improves overall rate of penetration and the performance of the entire drilling operation."

"Once we reach the pay, there are two strategies that we have with respect to wellbore placement," Allan said. "The middle Bakken tends to be a lot simpler geologically, with a much thicker pay zone, so we extend the reach of the lateral section—get it as far out as possible to extend exposure of the wellbore to the reservoir. Sometimes we have to deal with the fact that on the surface there are restrictions such as housing, lakes or rivers that prevent operators from placing the drilling rig over the target. In order to reach the target and access the reservoir, the rig needs to extend the drilling underneath the lake to access the reservoir, so we're getting ever-increasing land to step out.

"Then we have the lower Bakken and the underlying upper Three Forks," Allan continued. "Those reservoirs are much, much thinner. We don't have the same reservoir thickness to play with for wellbore placement so positioning the well becomes very important. In these cases, we use our Reservoir Navigation Service with downhole LWD tools that provide azimuthal gamma and azimuthal resistivity measurements. Our AziTrak tool allows us to see the upper and lower boundaries of the pay zone while drilling and to steer the well effectively by maximizing lateral wellbore exposure in the most productive interval of the reservoir. The tool transmits data to the surface that are converted to a 360-degree image of the borehole. The visual presentation of the images allows the operator to gently steer away from critical bed boundaries such as the top or bottom of the reservoir or fluid contacts while avoiding excessive doglegs that could adversely affect the drilling assembly or completions.

"The other caveat," Allan added, "is that now that we've got to the pay and we've kept in the pay, for a lot of people the initial production that they're getting in the Bakken doesn't allow the fastest exploitation of a particular zone, a particular area. So now we're designing the well plan immediately with artificial lift in mind. Rather than drilling the well, bringing it on, checking the decline curve and then putting a pump in, we are installing pumps almost immediately upon completion of the well."

"We primarily run electrical submersible pumps," Laing said. "You think of those as an impeller type of arrangement that provides suction downhole—where the curve meets the lateral—and the lower you can get the pump, the better. Sometimes we'll drill a sump for the pump to go in, and essentially it vacuums the hydrocarbons out quicker. We've got some new technology that we're using called the FLEX Pump that allows us to handle small production rates from as low as 50 to 90 barrels all the way up to over 2,000 barrels a day if required, depending on the well. It's made a huge difference to the industry and to the market, and we're really doing very well with it out in the marketplace today."

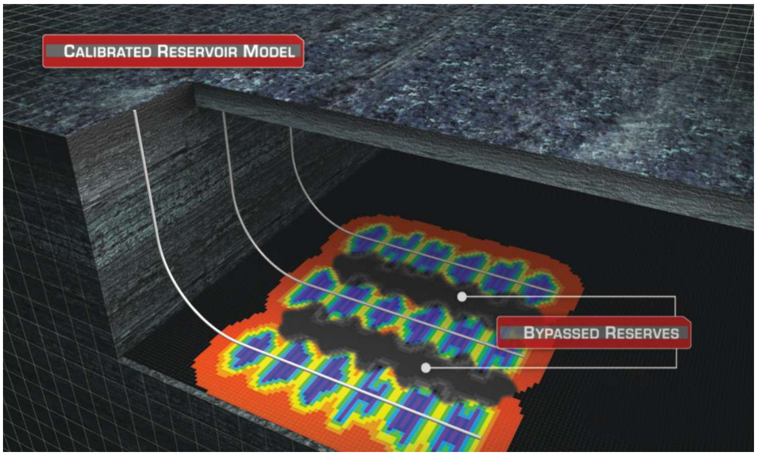
"[Pre-planning the artificial lift] has been a major change that's really come on in 2014 and will be increasing this year," Allan said. "It means literally planning the well with the pump in mind, as opposed to just retroactively trying to play catch up. Our new Production Wave production solution takes a holistic approach to the drilling, the completion, and then ultimately the enhanced production from a well. And to pick the optimal place for the pump, the best type of pump for the fluids, the hydrocarbons that we're trying to lift—because there are some variations—all that comes into effect as you are planning the well. If this is done retroactively, you have to compromise your pump because of the previous well design."

Innovation, environment and safety

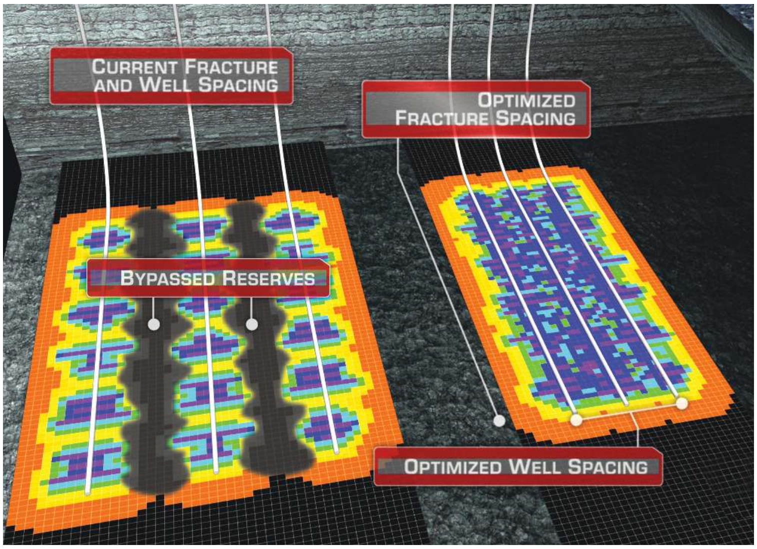
Building on its stated strategy, "the Wattenberg drilling team has maintained their focus on safety, innovation and environmental responsibility," Anadarko's Walters said. "Adopting a holistic approach to training, the team has realized a significant reduction in contractor total recordable incidence rate, reduced spills by implementing 'eyes-on' training and fluid transfer protocol, and enhanced water conservation by implementing a closed-loop and water-on-demand system. The team celebrated the first wells drilled with an electric rig, reducing noise and emissions and adding value as a top tier operator focused both on the community and the environment."

Probably one of the biggest challenges facing operators in the Bakken is stacked pays, Halliburton's Adams said. Operators are now staggering laterals, where previously, they put them on top of each other. They made the change to encounter less interference.

"If you can envision one lateral that might be in the lower Bakken and then an offset well would be in maybe the upper Bakken," Adams said. "They effectively place the wellbore laterals and the wells so that when they stimulate they don't have any interference between the two wells, and they can effec-



Reservoir models aid in defining how the fracture footprint impacts reservoir drainage. Subsurface insight will constrain the reservoir modeling to provide recommendations regarding proper well and fracture spacing. *(Images courtesy of Halliburton)*



Optimizing well and fracture spacing is a crucial need for the industry to improve reservoir performance. Technologies such as CYPHER Seismic–to-stimulation are critical to the optimization process to improve economic assets.

tively stimulate both sections of the Bakken. Services like ISD [integrated sensor diagnostics] can quantify the fracture footprint impact using a suite of sensors and directly correlate fracture effectiveness to well production. These inputs are a critical element to subsurface insight, which further improves the seismic-to-stimulation advantage and will accurately evaluate the trade-offs between staggered vs. stacked lateral placement."

Completions technology

"We know that two-thirds of the well cost is in completion," said Islam Mitwally, business development manager for Weatherford. "Being able to understand the heterogeneity of the formation and the change in the rock properties and reservoir quality is key. Of course, the laterals can have a huge effect on optimizing the completion. Weatherford has information evaluation technology to help the operator understand the change in geomechanics and petrophysics properties of the formation, how much of the oil they have and how easy [it will be] to drill or frack the well or the stages. And that feeds into completion optimization." The company helps operators reduce the variation in production from stage to stage and reduce the variation in production from well to well in the same field, he said.

"It feeds back into two of the overarching trends," Weatherford's Braley said. "What we mean by well production variance is that it's an issue that we see across the board in unconventionals, and this is the challenge for many operators. What that means is that operators may have several different wells within their lease or their acreage area, and those wells may be producing at or have initial production rates at vastly different amounts. At first glance, you're thinking, 'Gosh, you know I've got these 10 wells sitting here on this same space. Why is it that this well over here—and we've had the same completion design, the same drilling design—why is it that the production rate is so different from the one over there?' Maybe the one over there is a competitor or a neighboring operator's, not even theirs.

"By understanding the subsurface, we believe that integrating the formation evaluation data into your completion and drilling operations and designs can help alleviate some of the well production variance by better being able to custom fit your completion design for that particular area based on the rock and reservoir properties," Braley said.

"Well production variance is a huge issue in unconventionals, and we believe that the geometric fracking that has been going on for the last few years—where folks are just fracking straight down the fairway every set amount of yards—we believe that going in and placing those stages based on the subsurface data and like rock with like rock, you'll have better results with your completion, thus alleviating well production variance issues," Braley said.

> **"FROM THE COMPLETION PERSPECTIVE,** there's been somewhat of a renaissance."
>
> *—Pat Bent, Continental Resources*

In its stimulation operations, Continental Resources has focused on enhanced completion designs using a combination of crosslinked gel, slickwater and hybrid designs, all with higher proppant volumes per stage, Bent said.

"From the completion perspective, there's been somewhat of a renaissance," Bent said. "Historically at Continental, there were a fixed number of stages and a limited sand and fluid volume comprised of crosslinked gels. Over the last 18 months, we began to test a number of stimulation designs, varying everything from fluid composition to sand volume and concentration to stage interval length. We've narrowed that focus today to three basic designs that have resulted in significant improvement in our core operating areas."

In 2011, Anadarko started pumping a hybrid fluid design (60% slick water and 40% crosslinked fluid) with sand, Walters said.

"We have tested multiple fluids, including testing slick waters. Anadarko continues to have success pumping slick water with 40:70 with sand and is currently pumping about 95% of the wells with this design," Walters said. "Anadarko will continue to optimize the fracture design integrated with the spacing of the wells to maximize total recovery of the field."

As for fracture spacing, Anadarko started in 2011 with 200-ft intervals, which resulted in about 20 stages for a 4,000-ft lateral, Walters said. "Anadarko has tested both increased and decreased interval size. We have seen more success with decreasing the interval size and therefore increasing the total number of stages per well."

For Anadarko, the completions team has similarly enhanced its operations in the Wattenberg, Walters said. "With the increased usage of the stimulation centers using the water-on-demand infrastructure and dual-fuel technology, the team has reduced pad sizes by 50%, significantly reduced noise, dust and truck traffic, and greatly improved air quality by reducing emissions," Walters continued. "This has resulted in reductions of more than 300,000 truck trips or over 4.2 million miles of truck traffic. By using sound walls to decrease light and noise, the completions team has demonstrated that it is a 'best-in-class' operation, focused on the environment, the community, and safe, efficient, innovative and value-added operations."

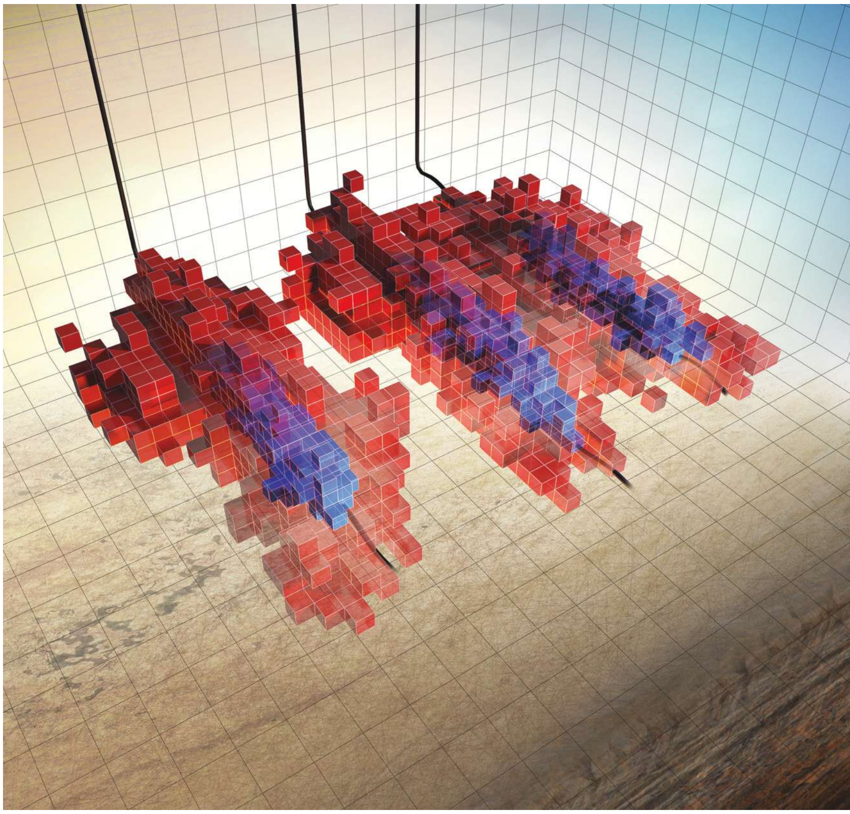
Sudhendu Kashikar

Operators have known that half of all stages installed in the last five years don't produce. This represents significant waste and unprofitable time and money. They want an extremely effective method of knowing the results of every fracture-stimulated stage.

There are ways to do that, according to Sudhendu Kashikar, vice president for completions evaluation at MicroSeismic.

"If you look at the Niobrara or the Bakken, one of the critical challenges in those particular areas is that you have stacked pay zones," Kashikar said. "With the Niobrara, you've got the Niobrara and the Codell. In the Bakken, you've also got the Three Forks and Bakken formations. The question is always, how do you effectively fracture and drain these reservoirs? Can you do it with a single well? Do you need multiple wells? How far should you space the wells? What's the actual treatment you need to optimize the stimulation of the individual zones?"

Kashikar continued, "We can analyze the productive SRV [stimulated rock volume] and understand the extension of the fractures in different directions, both in the vertical and lateral directions, saying, 'Is this frack staying within the zone? Is it extending from the Niobrara into the Codell, and if it's extending, how much is it extending?'" By doing this analysis, he said the company can get a very good understanding of what the optimal well spacing

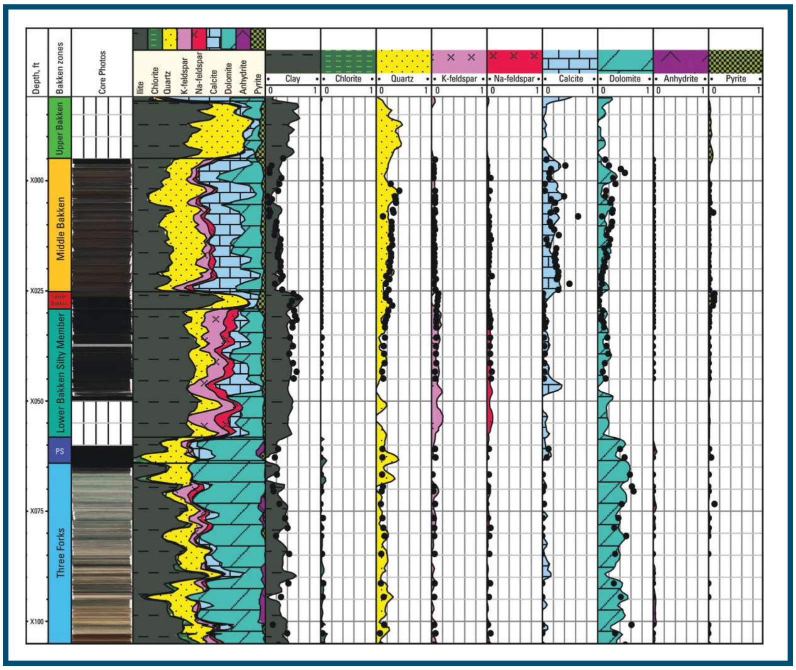


The image shows the total stimulated rock volume (SRV) in red and the productive SRV in blue. The SRV captures the volume of rock impacted by the hydraulic fracture treatment. The productive SRV captures the proppant-filled fracture volume within SRV and thus is the better indicator of the effectiveness of the hydraulic fracture treatment and the drainage volume. MicroSeismic uses the P-SRV to characterize the fracture effectiveness and drainage volume and evaluate completion options. *(Image courtesy of MicroSeismic)*

Evaluating Matrix Density

Operators need accurate assessment of elemental concentrations.

An operator who needed to evaluate matrix density for determining total porosity in the low-porosity, very low-permeability dolomitic limestones of the Bakken and Three Forks formations turned to Schlumberger's Litho Scanner high-definition (HD) spectroscopy service for a solution. The HD spectroscopy service, which determines total organic carbon (TOC) and corrects matrix density for organic content to correctly calculate total porosity, allowed the operator to obtain accurate assessment of elemental concentrations.



Mineralogy determined from Litho Scanner's elemental weight fractions is confirmed by core mineralogy. The core photograph shows the highly laminated nature of the Three Forks Formation, which can cause occasional scatter when comparing log data with standard core plug data. *(Source: from Schlumberger case study 12-FE-0033)*

Petrophysical evaluation of porosity and saturation in the low-porosity and very low-permeability dolomitic limestones of the Bakken and Three Forks reservoirs requires an accurate evaluation of matrix density, which is a function of formation mineralogy. However, conventional methods for determining mineralogy are not independent of the level of maturity of the organic content, formation salinity, density or resistivity, requiring the operator to conduct expensive and time-consuming coring operations for laboratory analysis to get the necessary quality of mineralogy data.

The accuracy of Litho Scanner service's elemental weight fractions, particularly for magnesium, and the standalone TOC output makes these measurements key to petrophysical modeling in complex lithology. The direct measurement of formation carbon coupled with an assessment of inorganic carbon from the mineralogy results in a robust, accurate TOC measurement that does not require core calibration, previous knowledge of the kerogen type or maturity, or optimization of empirical algorithms that rely on conventional core analysis.

Litho Scanner service's mineralogy and matrix density corrected for organic content made it possible for the operator to correctly determine the porosity without extensive sample collection and the lengthy wait for laboratory analysis.

As shown on the logs for elements and mineralogy, the accuracy of the element and mineral determinations from the HD spectroscopy service is confirmed by their close agreement with core analysis results. A similar confirming relationship exists for matrix density corrected for organic content by using the service's TOC output. ∎

Source: Schlumberger case study

should be and/or how the company can change the treatment in terms of either proper fluid volumes, amount of proppant, the stage spacing or the completion design to further optimize the treatment.

"We've gone from the dots in a box to an engineering answer that we can correlate directly to the completion design and to the performance of that particular completion design," Kashikar said. "That's where the value comes from, saying, 'How do I optimize and get the maximum recovery from each well? What parameters do I need to change?' We can understand and incorporate geology and whatever other information you have as an operator, so you can start making some informed decisions in terms of what's an optimum well spacing, should I be pumping more proppant or less proppant and is a plug and perf going to provide better or worse productivity compared to a sliding sleeve type of completion. We can quantify the different aspects of the completion design and allow the operator to make a more informed decision in terms of what the optimum completion design going forward should be."

Water usage and disposal

Along with its emphasis on cost reduction and the environment, Anadarko has made a commitment to use water in an efficient and responsible manner in Wattenberg, Walters said. "We have chosen not to use water supplies that are nonrenewable, such as deep aquifer groundwater. We have also chosen not to use water supplies that are in competition with agriculture in the region. Our primary source of supply for our well completion operations is treated effluent that we purchase from the City of Aurora [Denver]."

For efficiency, Anadarko has developed a water distribution system to pipe water throughout its service area to minimize water losses and eliminate a substantial amount of truck traffic, he continued. In three years, the company has been able to install more than 140 miles of water pipeline and move more than 70 MMbbl of water while avoiding more than 11 million miles of truck traffic.

Anadarko has established relationships with water agencies throughout the field to partner on mutually beneficial water facilities and conveyances that meet both short- and long-term needs, Walters said. "Partnering with local water providers has allowed us to facilitate improvements that will support regional water needs well beyond the activities of the company. We also stay actively engaged in local and regional water planning initiatives and educate stakeholders and the public regarding our safe and efficient water use and operations.

"We have an active management plan for our flowback and produced water and continue to find ways to increase our reuse of those supplies," Walters said. "Technology is leading the way for water treatment methods that provide water recycling with increased volumes and reduced costs, and Anadarko continues to adopt such technology as it becomes technically feasible for our operations."

Environmental and safety

Walters also pointed out the community and environmental initiatives that Anadarko has taken. "Innovations are helping Anadarko meet its goals of preventing spills, reducing emissions and minimizing the overall impact to the environment and surrounding communities," Walters said. He noted that over the past few years, Anadarko has begun implementing a tankless battery design to reduce surface impacts, emissions and spills and has engineered a new wellhead and flowline design to avoid failures. The company also has advanced development and use of the stim centers and introduced dual-fuel completion equipment to reduce emissions. Anadarko now transports 80% of its produced oil through pipelines and recently, commission train 1 at the Lancaster Gas Plant, processing 300 MMcf/d using electric compression to eliminate combustion emissions, Walters said.

In another phase of the company's initiative to use technology to not only improve operations but also improve its environmental footprint, Anadarko's Wattenberg completions team has implemented dual-fuel technology with some of the Halliburton crews in Colorado.

"This system uses Caterpillar's Dynamic Gas Blending engine technology to mix natural gas and diesel fuel to power the pump trucks," Walters said. "By using up to 70% natural gas in the fuel mixture, Anadarko is leading the industry toward decreased spills and lower carbon emissions and is helping to make the process safer for all of the employees and contractors on location." ■

Midstream **Development Continues Apace** in the **Bakken and Niobrara**

One big processing plant is due in the DJ Basin, and private equity remains interested.

By Gregory DL Morris
Contributing Editor

Not so very long ago during the boom days of the Bakken and Niobrara, more than a few producers wondered aloud why gathering and processing could not keep up with drilling plans and actual liftings. Now, most midstream operators are carrying on with plans to complete gathering, processing and transportation projects, despite the steep drop in rig counts in the Bakken and Niobrara and revised production forecasts that call for growth to slow to essentially a plateau. Some of the producers that had been hectoring their midstream partners to hurry along might now be breathing more private sighs of relief at the slow but steady pace of midstream growth in the two basins.

One of the biggest projects that is close to completion is DCP Midstream's Lucerne 2 complex in Weld County, Colo., northeast of Denver. It is due to be in service during second-quarter 2015, and with just a few months to go before that target, the project is on schedule, said Brian Frederick, president of asset operations for DCP Midstream.

Brian Frederick

DCP is a 50:50 joint venture (JV) of Phillips 66 and Spectra Energy that includes DCP Midstream Partners. Phillips has featured DCP in its capex updates, noting that the parent company "will use its infrastructure to launch new gathering, processing and NGL growth projects, mainly in the Niobrara, Denver-Julesburg [DJ], Eagle Ford and Permian basins. DCP also expects to increase natural gas processing capacity in these basins and complete other gathering system expansions during 2015. Phillips 66's share of DCP's 2015 planned capital expenditures is $550 million," according to a Phillips 66 press release.

"We have grown significantly in the Niobrara, particularly the Denver-Julesburg Basin," Frederick

said. "We have been matching plans and forecasts from our production partners and from other sources with our own infrastructure. Our time cycle is usually longer than theirs, so it is essential that we work as a partnership. We always try to match gathering with processing capacity." That means keeping in close communications as conditions change, both with E&P customers and in downstream markets, Frederick added.

The Lucerne 2 plant will be a 200-MMcf/d deep-cut cryogenic facility in the liquids-rich DJ Basin. It will become part of a nine-plant system owned by the DCP enterprise and will increase total capacity of the system to about 800 MMcf/d. Residue gas will move out on the CIG/High Plains system while liquids production of almost 30 Mbbl/d will be hauled on the Front Range and Texas Express pipelines to the Mont Belvieu hub.

"Lucerne 2 is coming along nicely," Frederick said. "We are confident that it will be in operation by the second quarter." To underscore the point that DCP has grown significantly in the DJ Basin, he added, "Two years ago, we had less than 400 MMcf per day of capacity in the play. We are not just adding capital projects but also are spending time and money on operating an efficient system. One year ago we added our last plant, and it was full within a year. We feel good about our ability to grow and expect the same with Lucerne 2."

Balancing old and new

One of the challenges in the DJ Basin, Frederick explained, is that it has a long history of conventional production, on top of which has come a burst of shale development. "There are lots of older vertical wells that are declining in production with much lower pressures. Then come all these newer horizontal wells much earlier in their life cycles and with higher pressures. We spend a lot of time studying the hydraulic balance and looking for opportunities to improve performance. It almost requires two systems, but we have about 3,000 miles of line in the greater DJ area, so we have a lot of pipe to work with."

Two further variables are layered on top of that historical life cycle, Frederick added. There is the normal play- and field-specific development cycle of discovery, delineation and connection, and then there is the macroeconomic picture of supply and demand. All of the midstream investment and expansion in the Niobrara, Bakken and across the country are now taking place against a backdrop of sharply lower prices for oil and gas. Rig counts are tumbling, and producers are pulling back on capital programs.

That said, Frederick continued, "We have put a lot of effort into looking at the DJ Basin and have determined that it is one of the top four or five plays in the country. There will be some decline in activity, but it is likely to lose rigs more slowly than other plays."

He said that in some areas "producers have talked about reductions of rig counts up around 20% to 25%. We are cognizant of that and confident that we can work with producers to ensure efficient midstream operations," Frederick said. "We have had a lot of discussions within DCP about integrated systems. Lucerne 2 will be our ninth plant in the DJ, so we can do a lot of different things to keep wells of all kinds operating and keep streams moving on an optimal basis. In an environment like this, every cubic foot of gas is important."

Beyond Lucerne 2, DCP's only firm plans for 2015 in the DJ are incremental debottlenecking projects and enhancements to compression. The firm has no Bakken operations but operates a gathering system in another section of the Niobrara—the Powder River Basin. "There has been good growth in that part of the play, and we continue to monitor the area," Frederick said. "At the present, there are no big expansions planned, just incremental improvements."

Private equity stays keen

Beyond big plants, big capital is still flowing into the Bakken and Niobrara. The new year was just two weeks old when Five Point Capital Partners, a private-equity firm based outside Houston in The Woodlands and focused on the midstream sector, closed its Midstream Fund I and Fund II with total equity commitments of more than $450 million, exceeding the fundraising target of $400 million. In its release about the closing, the fund indicated that it received strong support from a diversified base of investors, including leading public pension funds, pre-eminent university endowments and foundations, multinational corporations, insurance companies, fund-of-funds and family offices. Debevoise & Plimpton served as legal counsel, and Mercury Capital Advisors served as placement agent.

Fund I is a special-purpose vehicle of about $30 million to invest in Twin Eagle Resource Management, a midstream energy infrastructure and energy marketing business with operations in the Permian, Eagle Ford, Bakken and Niobrara. Fund II is a much larger traditional blind pool that also has invested in Twin Eagle as well as backed a management team to form Redwood Midstream, a multiphase oil, gas and liquids gathering and processing business with a focus on the Permian, Eagle Ford and Midcontinent plays.

"We see extraordinary opportunities in the current midstream energy market," said David Capobianco, managing partner of Five Point, in a company press release. "We believe that the combination of near-to-intermediate term dislocation and long-term growth will create a superior climate for our focused investment strategies. We are well positioned to execute on our investment approach, which we believe protects the downside while maintaining asymmetric upside in the midstream companies we build through buyouts and growth capital investments within the midstream sector."

Bringing the focus a little tighter, Capobianco said, "This is an interesting moment for the Bakken. The rig count will continue to fall year-over-year. Production likely won't begin to decline until 2016, but it will decline eventually. At the same time, cost curves are coming down very dramatically, so it is tough to say at the moment what breakeven would be. We do know that real cash flow and liquidity are driving drilling decisions."

Capobianco reckons that the Niobrara is a bit better off for now than is the Bakken and is seeing a continued need for gathering and processing. "The long-haul infrastructure investments in the Bakken will slow, and differential advantages for better-connected basins will remain wide. Of course, hard infrastructure that is already in the ground will continue to flow," he said.

In sharp contrast to some observers who believe that the current downcycle is likely to see significant volumes of crude shift from rail to pipeline, Capobianco said, "Rail will continue to be an important mode of transportation in these markets, because the case for new capital-intensive takeaway options, like long-haul pipelines, is challenged in times of low commodity prices and uncertainty."

Costs dropping fast

Returning to the key driver of cost, Capobianco explained that several different factors are in play at once. "The learning curve on drilling and development lowers cost and improves efficiencies over time, even as the price of oil and gas is going down. The prices of assets and crews also are going down." The metatrend is that things are less expensive because things are less expensive—the high prices in a boom market come from actual costs as well as opportunity costs. Those dissipate in flat or declining markets. "Instead of having to book months in advance for a rig or a frack crew, you can now name your price for a rig that was going to be laid down otherwise. The whole dynamic has changed," he said.

He also credited the drill and fracture crews with learning curves just as steep as the rigs they use. "The well data and associated costs we all see are backward looking. They show us what has been done, not what can be done. The service companies do a great job well to well for one client, and the knowledge transfer is great project to project."

What that translates to in terms of midstream opportunities for Five Point is what Capobianco calls "the first 25 miles. That is not literally 25 miles; it could be 250. But we are interested in trucking, gathering, in-region storage and blending, and transloading for crude; gathering and processing for gas; sand and water for services; [and] eventually fractionation and liquids handling. We are not talking about pipeline takeaway capacity."

Broadly, Capobianco said, Five Point is "looking for dislocations [or] for pockets of distress. When capital was easy, small and midsized producers often were able to provide their own midstream needs. Now capital into this business is much more constrained, and there is a much larger role for investors like us."

Jodi Quinnell, manager of crude oil analytics at Genscape, said that regional developments should not be lost in the larger global macroeconomic trends. For example, in a recent report, she detailed that "Permian production started 2015 on a rather weak note, curtailed by freeze-offs caused by below freezing temperatures. Producers and marketers scrambled to meet sales quotas with the decreasing oil production volumes by drawing from storage in the basin."


Jodi Quinnell

Production in the basin for the week ending Jan. 3 averaged lower by about 460 Mbbl/d for a total of about 2.3 MMbbl impacted by the freeze-offs. During the same week, withdrawals from storage totaled 2.1 MMbbl, representing a 26% decrease in stocks over the previous week, as producers strained to make up for the lost production volumes, according to the report. Midland storage saw the biggest change in volumes with a draw of 1.3 MMbbl, for a 34% drawdown in inventories.

Production flattening, not declining

While barrels from the Permian cannot necessarily be replaced one for one by barrels from the Bakken or Niobrara, either logistically or in their characteristics, the flexibility of rail does offer some options to marketers and refiners that can make substitutions.

In the same report, Quinnell reflected that in 2014 a similar occurrence transpired when production was impacted at the end of November by an ice storm, with a total loss in production of about 1.4 MMbbl. "Producers and marketers again looked to storage to fill the void with withdrawals from storage between November and December 2013 totaling 1.2 MMbbl.

"After recovering from the freeze-offs, Genscape is expecting that production will climb through May 2015 to just under 1.8 MMbbl/d before starting to taper off as a result of the decrease in crude prices and corresponding assumed drop in rig count. Over the course of the next nine months, Genscape is expecting oil rigs to drop by 300 from about 532 in December 2014," according to the report.

"Seeing rigs pull back across the country, we are anticipating significantly more will leave the fleet," Quinnell said. "We expect to see 60 or 70 more rigs leave North Dakota, and the outlook for production is flattening over the next few years. That could change the midstream outlook but not necessarily."

She reiterated that production forecasts are flattening, not declining, and that by their nature, midstream developments lag upstream. If the price declines that have driven the retreat among producers are of short duration, then this period could be the pause that refreshes midstream growth in the Bakken especially, where it has been critically short. If the price decline is long-lived, then midstream and upstream can rationalize and grow incrementally in close coordination when recovery does come.

"Today's barrels still need to get to market," Quinnell said. She also noted an important detail that midstream operators would do well to bear in mind: "Often in a declining rig environment, the rigs and the crews that are left are the best ones. So it is not unusual to see drill times start to come down and well efficiency start to increase. Average initial production values also climb, because only the most prospective wells are completed by the best crews and rigs. The not good ones are not included."

One further wrinkle is that wells and midstream assets not yet in commercial service but close to completion are not likely to be abandoned just shy of the finish line.

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- Detailed wall map

"Anything close to connectivity will be completed, especially in the Niobrara as new processing plant infrastructure is close to completion. [This is] less so in the Bakken as it is more established on the midstream side," Quinnell said.

All in all, the rig count is a leading indicator, and one that cannot be converted back to declines in completion or production in any linear calculation. Once molecules are on their way to market, the current downcycle in prices could give all parties—shippers and carriers, buyers and sellers—a chance to rationalize their supply chains.

Projects pressing ahead

"We have seen some decrease in rail loadings ever since the Pony Express Pipeline came onstream," said Hillary Stevenson, manager of supply chain networks for Genscape. She noted that it is still a bit early to tell which of the several rail and pipeline projects in the Bakken might be delayed and if so, by how much. Stevenson said few are likely to be cancelled outright, but some schedules might be extended now that the pressure is off to get online.


Hillary Stevenson

The calculus for any given shipment of crude is the best netback. With prices and freight rates changing rapidly, that is something of a moving target. "The cheapest place to send Bakken barrels right now is to Cushing, [Okla.]," she added. The nearby Stroud terminal in Oklahoma, operated by EOG, is running at about a $5 to $6 discount to East Coast destinations, she said.

"Don't forget that some pipeline and rail transportation will continue to flow as it is because of long-term contracts," Stevenson added. "Wells that are now being completed will go to rail or pipeline depending on the best netback." Early indicators have been mixed. For example, unit train deliveries at Stroud ceased in early November 2014, which was just about the time that the Pony Express Pipeline from Guernsey, Wyo., to Cushing, was brought into service by Tallgrass. That shift was taken as a sign that producers might be favoring pipe, but unit trains began arriving at Stroud again in January.

Producers and carriers seem to be hedging their bets, maintaining all options. EOG was among the first independents to go big into crude-by-rail, as reported extensively by Hart Energy's *Crude in Motion* supplements. The company's first shipments from its loading facility at Stanley, N.D., to Stroud took place as far back as 2009. Underscoring that commitment in capital and planning for rail transport, EOG also started building its Hawthorn Pipeline from Stroud to Cushing that same year.

With plenty of rail infrastructure in place, the focus has shifted to pipe. Late last year, Enbridge slid the projected completion date for its Sandpiper line by a year, but the cited cause was regulatory delays, not prices or production in North Dakota. Byron Neiles, Enbridge's senior vice president of major projects explained at the company's investor conference in Toronto that "even though we've secured all of the required approvals in North Dakota, close to 100% of the right-of-way and more than 90% of the lands required in Minnesota, the regulator reversed a decision it took earlier this spring denying opponents' motions to extend the process as well as to bifurcate or decouple the route and need processes of the review."

Moreover, Neiles added, regulators "required that those processes be conducted one after the other rather than in parallel. And then, furthermore, asked that six alternative routes proposed by third parties be evaluated. So the net effect of this is that this process is going to push us into 2017. This reflects a continuing pattern that we're seeing across North America where regulators are lengthening their processes to ensure that their conduct and their ultimate decisions can withstand legal scrutiny. That said, we've been operating in Minnesota for more than 65 years, and the demand from regional refineries is strong as is our commitment to operating that pipeline safely and being a leader in emergency response."

Piping along

The Sandpiper project is proposed to transport light crude oil from Enbridge's Beaver Lodge Station, near Tioga, N.D., through Clearbrook, Minn., to an existing terminal in Superior, Wis. Sandpiper would be about 612 miles long, with a 24-in. diam-

DCP's O'Connor Plant in Weld County, Colo., provides deep-cut gas processing on up to 160 MMcf/d produced by Niobrara wells. *(Photo courtesy of DCP Midstream LLC)* eter from Beaver Lodge to Clearbrook and a 30-in. diameter from Clearbrook to Superior, according to company press releases.

Enbridge's Line 81 terminates in Clearbrook, and Sandpiper would carry those additional volumes to Superior. The new pipeline would generally follow Enbridge's existing pipelines and/or other infrastructure right-of-way. In Minnesota, more than 75% of the planned route follows pipelines and other infrastructure already in operation, according to a company press release. Enbridge also will install a new pump station and tanks for Sandpiper in Clearbrook.

"Sandpiper, designed to transport 225,000 barrels a day out of North Dakota, is undergoing regulatory proceedings currently and is expected to be in service in 2017," said Guy Jarvis, Enbridge's president of liquids pipelines, also speaking at the company investor conference in September 2014. Marathon Petroleum is both an anchor shipper and a partner in each of the Sandpiper and Southern Access Expansion projects.

If Sandpiper and other projects are completed as planned, Enbridge would have total crude transport capacity of 650 Mbbl/d to transport crude from North Dakota; 225 Mbbl/d on Sandpiper; about 200 Mbbl/d on the Legacy North Dakota system; 145 Mbbl/d on the Bakken expansion project, which transports North Dakota volumes north through Saskatchewan to the mainline at Cromer, Manitoba; and 80 Mbbl/d from the rail-loading facility in Berthold, N.D.

"To recap what our system will look like upon completion of all of these projects by the end of 2017, our mainline system will have capacity ex-Gretna [Manitoba] of 2.85 million barrels per day, along with an ability to receive up to 200,000 barrels a day off the North Dakota system at Clearbrook, and an additional 225,000 barrels per day from North Dakota on the Sandpiper system at Superior," Jarvis said.

Jarvis added, "If the volumes available to the mainline turn out to be stronger than anticipated, there's a potential for growth on our system of an excess of 500,000 barrels per day. The Sandpiper project could be expanded by up to 160,000 barrels per day, and Line 3 will have remaining unutilized capacity into Superior of 370,000 barrels per day. While it is expected that these volumes can be accommodated on Sandpiper and Line 3 at very low cost, significant new investment will be required downstream of Superior to eliminate the bottleneck that would exist there."

One "significant capital requirement would be the need to consider the twinning of [the company's] Southern Access Pipeline, otherwise known as Line 61, which would remove the bottleneck at Superior and transport additional volumes to Flanagan [Ill.]. Once at Flanagan, we expect that we also would look to undertake expansions of our market access programs to add low-cost capacity on Flanagan South and Seaway, the Southern Access Extension and to serve markets in eastern PADD II and eastern Canada," Jarvis said.

"Depending upon the volume of this growth opportunity and the balance between light and heavy crudes, it also is possible that new access to the eastern U.S. Gulf Coast could be contemplated," he continued. "When you look at the growth in North Dakota, we think there's a strong probability that by the end of the decade, we will have been in a situation where we can expand Sandpiper. That's part of the plan and getting in there and getting it built in the first place."

Despite the current plateau, production forecasts in the Bakken, from the North Dakota Pipeline Authority to Enbridge, are all calling for continued growth. "The key driver behind this upward revision has been the significant jump in well potential and tighter spacing," Jarvis said.

Big players increase their presence

Late last year, Tesoro Logistics leaped into a major midstream position when it paid $2.5 billion for QEP Field Services, a gathering and processing business. The company has 2,000 miles of gas and oil gathering and transmission pipelines in the Rockies and North Dakota, in the Uinta, Vermillion, Green River and Williston basins, according to company press releases. Gas capacity is 2.9 Bcf/d, and crude capacity is more than 54 Mbbl/d. The deal includes four gas processing complexes with total capacity of 1.5 Bcf/d and one fractionation facility with 15 Mbbl/d of capacity.

Under the structure of the deal, Tesoro Logistics made the acquisition. Not surprisingly, the first order of business will be to sign a contract with its refiner parent that will, according to the official press release, "substantially reduce the commodity exposure related to certain natural gas processing contracts held by QEPFS [QEP Field Services LLC]."

In first-quarter 2015, the acquisition is expected to generate about $65 million to $70 million of EBITDA on a consolidated basis before transaction and integration expenses, according to a Tesoro Logistics press release. For the whole year, Tesoro Logistics expects the acquisition to generate consolidated EBITDA of about $250 million to $275 million. This includes about $20 million of savings from QEPFS historical expenses relating to allocated costs and third-party spending.

Tesoro Logistics expects to spend about $100 million in 2015 for capital projects relating to the acquired assets, the release said. Those projects primarily seek to build out additional natural gas gathering pipelines to support the expected 10% to 15% natural gas production growth in the dedicated service areas, including the Bakken and southern California. In the long run, Tesoro Logistics aspires to have half of its revenue come from third-party customers.

Also, late last year, Phillips 66 and Energy Transfer Partners (ETP) formed a pair of JVs to build Bakken oil pipelines: the previously announced Dakota Access Pipeline (DAPL) and Energy Transfer Crude Oil Pipeline (ETCOP), according to company press releases. "Energy Transfer holds a 75% interest in each joint venture and will operate both systems. Phillips 66 owns the remaining 25% interests and will fund its proportionate share of the construction costs. DAPL and ETCOP are expected to begin commercial operations in fourth-quarter 2016," a press release said.

Based on contractual commitments to date, DAPL is expected to deliver more than 450 Mbbl/d of crude oil from the Bakken/Three Forks to Midwest refineries, unit-train rail-loading terminals, and the Gulf Coast through an interconnection in Patoka, Ill., with ETCOP, a press release said. ETCOP will move crude from the Midwest to the Sunoco and Phillips 66 storage terminals located in Nederland, Texas.

"We are in the early stages of the process," an ETP official said. "This is still a proposed project. We have the shippers on board, and now we are in the state-by-state approval process. The last one to get started was Iowa in January. We are also out talking to landowners in the easement process."

Tesoro Logistics' Black Forks processing complex facility in Wyoming is part of the ex-QEP assets. *(Photo courtesy of Tesoro Logistics)*

ETP owns and operates about 35,000 miles of gas and gas-liquids pipelines. It also owns all of Panhandle Eastern Pipe Line and Sunoco, with the latter including crude and refined products pipelines, terminals and marketing. ETP also owns 70% of Lone Star NGL, a JV in gas liquids storage, fractionation and transportation, according to company press releases. ■

Near-term Slowdown Forecast for Bakken, Niobrara

Core areas of the two plays are set to attract the majority of drilling interest due to lower breakeven prices.

By Laura Atkins
Executive Director, Upstream
Stratas Advisors, a Hart Energy company

Two of the largest tight oil plays in North America are the Bakken/Three Forks and Niobrara. Both plays have experienced rapid production growth since 2006. The Bakken play has made North Dakota the second largest oil-producing state in the U.S., second only to Texas. Colorado's production is higher than in recent memory, having increased from a low of 45 Mbbl/d in 2000 to more than 180 Mbbl/d in 2014.

The Bakken and Three Forks formations are located in the Williston Basin, which extends over large areas of North Dakota and Montana. The play covers about 23,000 sq miles within the boundary shown in Figure 1. The contours indicated on the map are a valuation index based on the underlying geology and are derived from a weighted average of the Bakken and Three Forks isopach, Bakken Shale hydrogen index and Middle Bakken water saturation. The hydrogen index has been modified to account for oil that has migrated through the Middle Bakken to areas where the shale maturity is marginally within the oil window. The water saturation increases rapidly along the eastern edge of the play, resulting in a sharp boundary between the core of the play and a region of high water production. The geology varies significantly over the play area, and the valuation contours are strongly correlated with well performance; wells outside the core areas as indicated by the darker shaded regions on the map have been marginally productive and generally uneconomic.

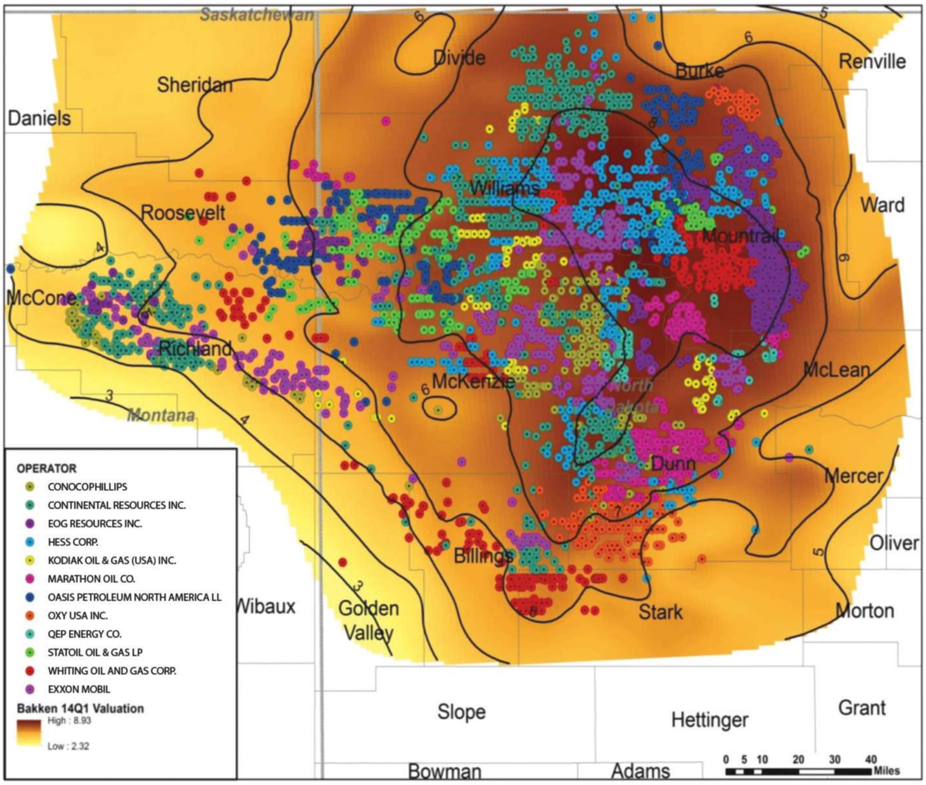
The Bakken development began in the early 1990s in the Elm Coulee Field in Richland County, Mont., in 1990, and in areas in North Dakota where the Upper Bakken Shale is naturally fractured. Drilling in the Elm Coulee Field began to accelerate in 2003 and peaked in 2012, after which drilling activity has declined.

By far, the largest numbers of wells are concentrated in counties in the core area of the play in North Dakota in Mountrail, Williams, McKenzie and Dunn counties. Many operators have been experimenting with 80-acre well spacing in these counties, contributing to the large numbers of wells. Well counts by county are presented in Table 1.

To create the forecast, Stratas Advisors, a Hart Energy company, used history-matched type curves and well count forecasts for each of the top operators within each contour area. Multiple type curves are used to represent the range of well productivities within each contour area. The average type curves for each contour are shown in Figure 2. The primary core area, C8, was divided into north and south because the decline patterns vary because of the change in the hydrogen index. Wells in the north exhibit more harmonic decline behavior while those in the south generally follow a power law relationship. There has been very little drilling below contour area 5.

Since fourth-quarter 2014, oil prices have fallen substantially. Though oil prices might have stabilized, Stratas Advisors expects low prices to prevail into 2017. Low oil prices have caused many operators to reduce capital spending, which is reflected in the number of rigs being deployed in the Bakken play. This stood at 191 rigs in October 2014, which fell to 165 the first week of January and to 145 by the first week of February. The forecast assumes reduced drilling for the next two years, after which Stratas Advisors expects oil prices to recover. This dramatic reduction in drilling activity results in declining production in 2016 and 2017, after which it begins to grow again. This is consistent with economic analysis by Stratas Advisors that indicates average breakeven wellhead prices for the Bakken core and contour areas 7 and 8 to be \$45/bbl to \$65/bbl. Breakeven prices are much higher in the outer regions of the play.

Figure 1. Bakken/Three Forks Valuation Map



(Source: All images by Stratas Advisors, a Hart Energy company)

Table 1. Bakken/Three Forks Wells by County

COUNTY	WELLS DRILLED AS OF 2Q 2014
McKenzie	2167
Mountrail	2027
Williams	1415
Dunn	1386
Richland	999
Divide	551
Billings	258
Burke	236
Stark	157
Roosevelt	123
McLean	28
Golden Valley	22
Other	68

(Source: Stratas Advisors Workbench database)

In this forecast, yearly average oil production declines by 28 Mbbl/d from 2014 to 2015, and another 14 Mbbl/d from 2015 to 2016. In contrast, the Stratas Advisors forecast from third-quarter

Figure 2. Bakken/Three Forks Average Type Curves by Contour Area

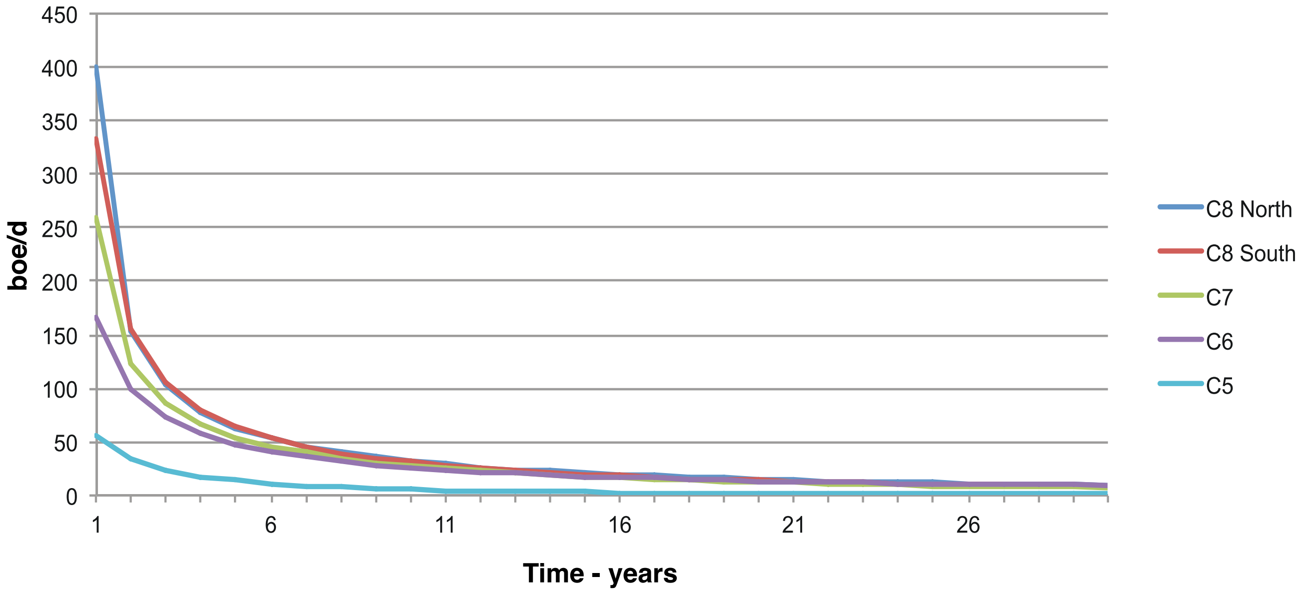
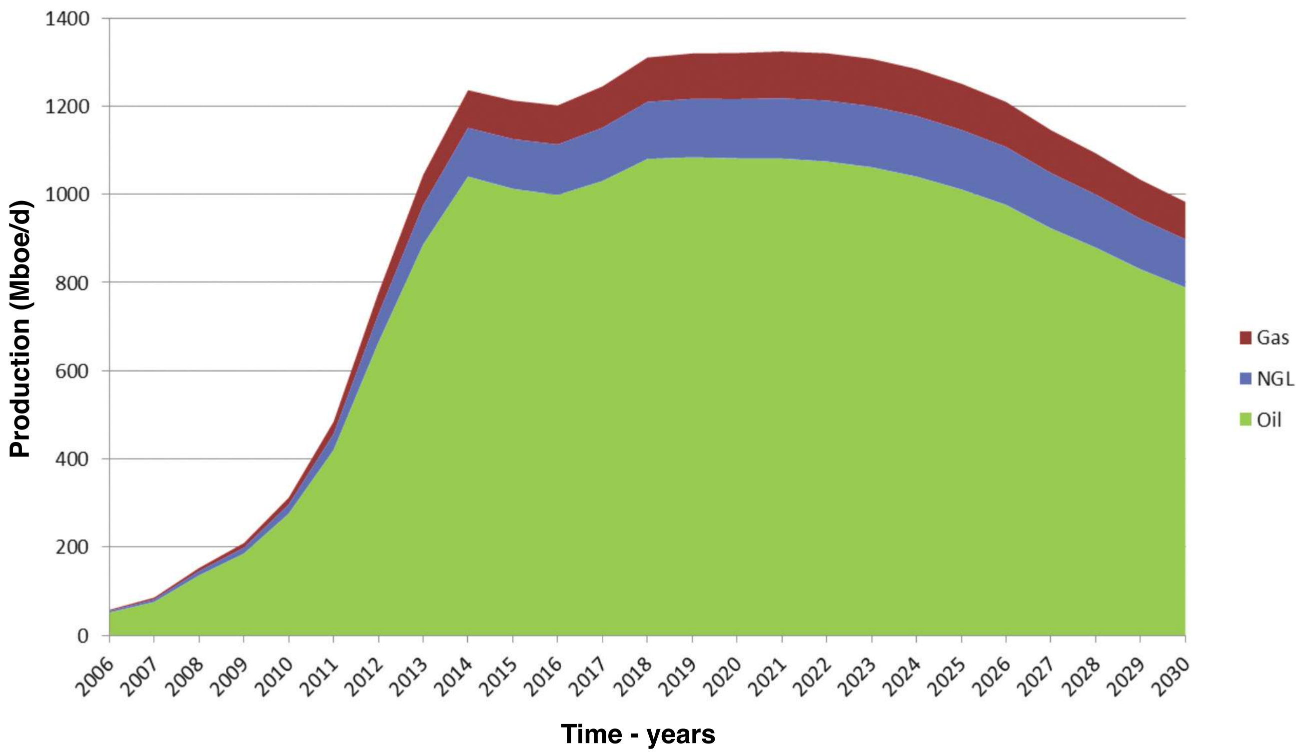


Figure 3. Bakken/Three Forks Production Forecast



2014, before oil prices began to fall, indicated that Bakken yearly average production would increase by 72 Mbbl/d from 2014 to 2015. In this low-price forecast, NGL production remains flat even with declining oil production because the gas-oil ratio is increasing over the highly developed parts of the play. Over time, the play-wide average hydrocarbon splits will change as the oil fraction decreases while the average NGL and gas fraction increases.

Figure 4. Niobrara Tight Oil Valuation Maps

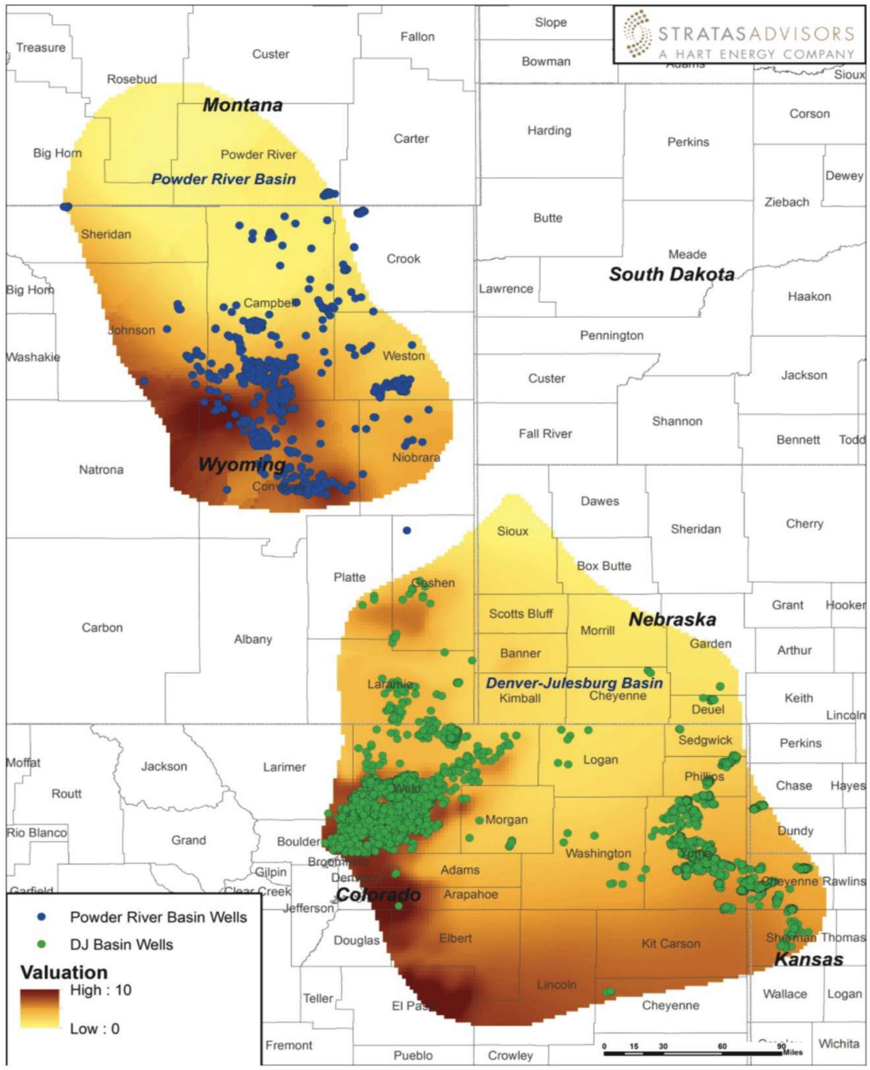


Table 2. Historical Wells in Tight Oil Formations, DJ Basin and PRB

	DJ BASIN	POWDER RIVER BASIN
Total wells	23,664	3,870
Total HZ wells	3,836	2,545
Total HZ wells since 2008	2,497	1,077
Total V wells since 2008	7,341	22

Niobrara

The Niobrara Formation is the primary source rock for the numerous conventional reservoirs that are found throughout the Rocky Mountain region. It was deposited 90 million years ago during the Late Cretaceous Period and is composed mainly of a blend of low-permeability, highly organic shales, chalk and marls. The deposit is present throughout the Rocky Mountains and appears in various basins across Colorado as well as in the neighboring states of Wyoming, Kansas and Nebraska. The Niobrara play is found in the Denver-Julesburg (DJ) Basin in Colorado and the Powder River Basin (PRB) in Wyoming and includes the Niobrara Formation as well as several other tight oil formations such as the Codell and J-Sand formations in the DJ Basin and the Niobrara, Parkman, Shannon, Sussez and Turner formations in the PRB.

The valuation map (Figure 4) is derived from a weighted index of the Niobrara vitrinite reflectance, thickness and structure in the two basins of interest. The wells shown on the map are those drilled after 2008 and are concentrated in Campbell and Converse counties in Wyoming and in the Wattenberg Field in Colorado. Another cluster of wells is found along the eastern edge of the DJ Basin in Colorado and Kansas.

Companies have been drilling wells into the Niobrara and other formations in these basins for several decades. The early wells were mostly vertical.

Figure 5. DJ Basin Tight Oil Type Curves

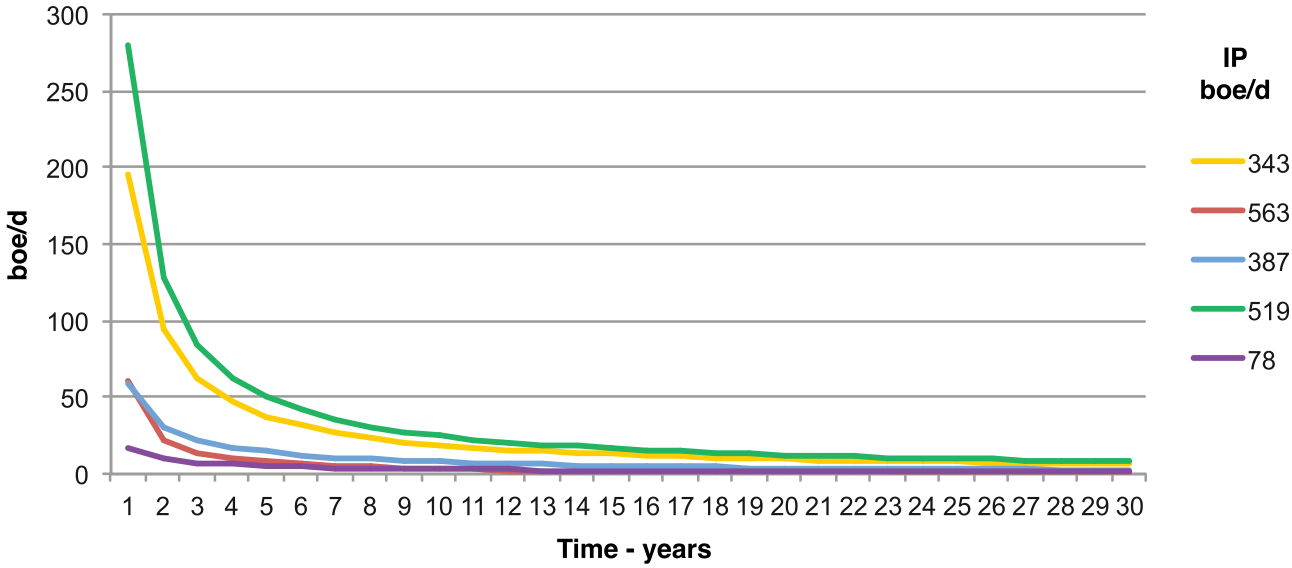
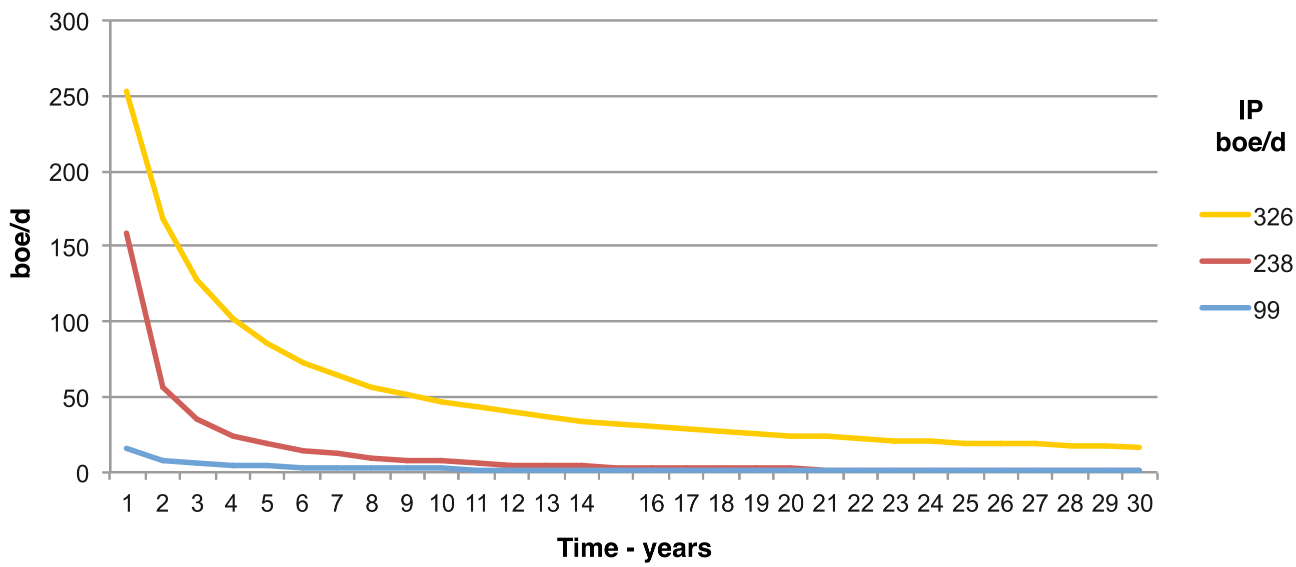


Figure 6. PRB Type Curves



Though they were relatively inexpensive to drill, they produced at very low rates. Horizontal wells also were drilled in the early days, but the modern technique of longer laterals with multistage fracks began in earnest around 2008. In the DJ Basin about 2,500 horizontal wells have been drilled since 2008. The PRB has about 2,500 horizontal wells with 1,100 drilled since 2008. The most productive wells on average are those in Converse County, Wyo.

Table 2 indicates the historical well counts in the tight oil formations that are part of the play

Figure 7. Percentage of Wells in Each Initial Rate Bucket (Type Curve) in the DJ Basin

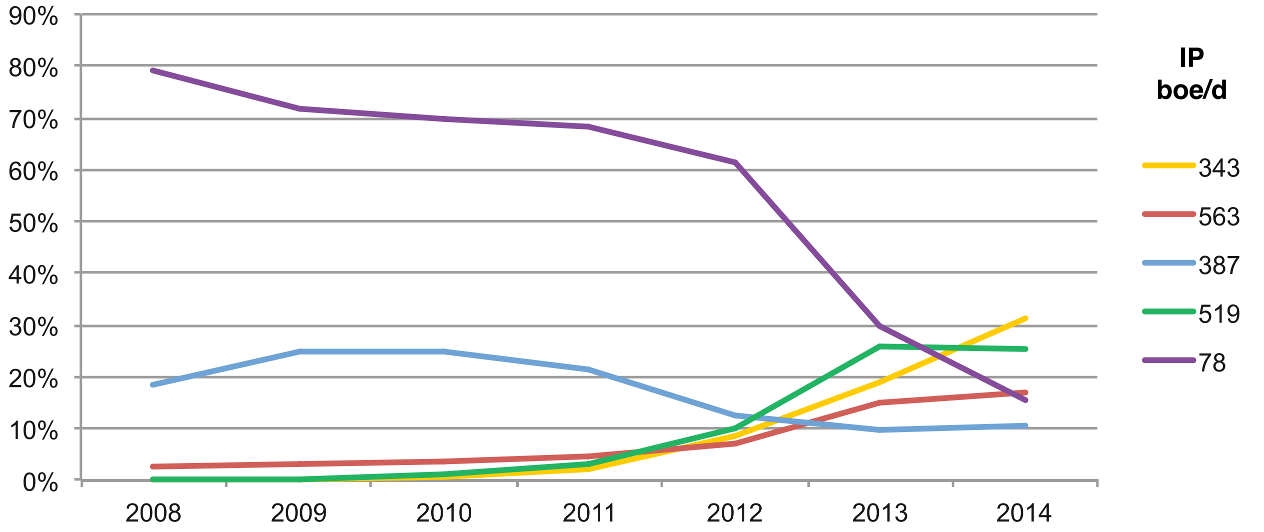
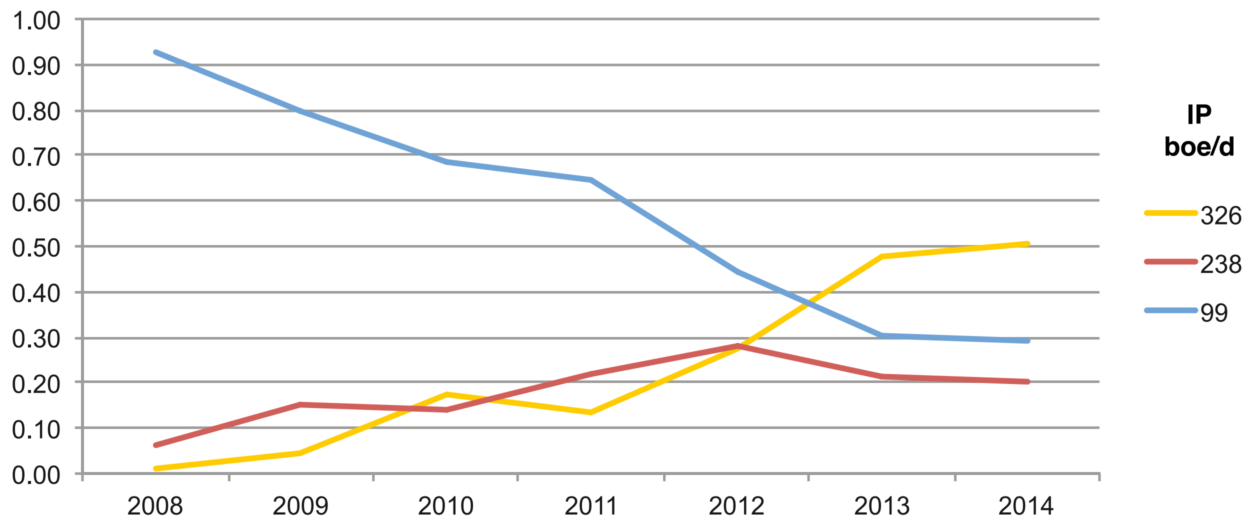


Figure 8. Percentage of Wells in Each Initial Rate Bucket (Type Curve) in the PRB



forecasts. The PRB, which was a major coalbed methane play, is a much more recent tight oil play. Since 2008, very few vertical wells have been drilling in this play. Operators continue to drill large numbers of vertical wells in the DJ Basin, though horizontal drilling also is increasing.

Stratas Advisors forecasts production by basin in the Niobrara tight oil play. Well productivities vary considerably between vertical and horizontal wells and within each well type. Five type curves are used in the DJ Basin and three in the PRB. More type curves are necessary in the DJ Basin because of the large

Figure 9. DJ Basin Tight Oil Production Forecast

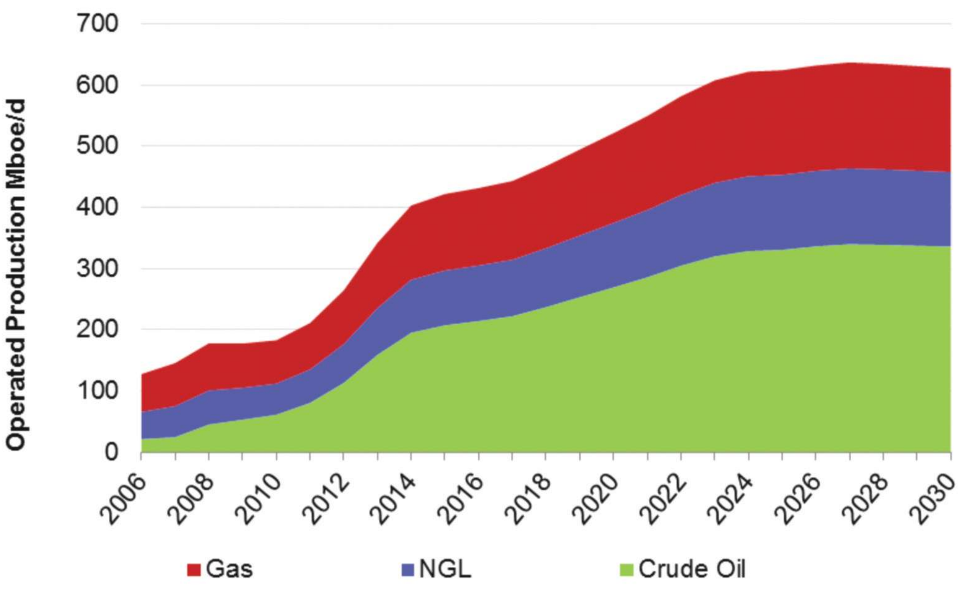
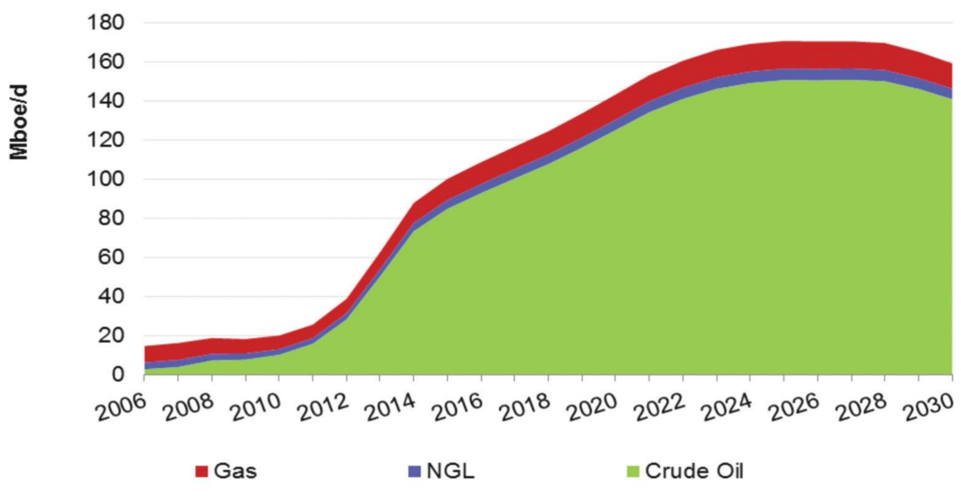


Figure 10. PRB Tight Oil Production Forecast



number of wells. The wells that are represented by the lowest rate type curves are generally vertical wells.

Three type curves were used in the PRB. Most of the wells are horizontal and follow one of the two higher rate type curves.

Well performance in both basins has been improving since 2008. Figures 7 and 8 show the percentage of wells that fall within each IP rate "bucket," which determines which type curve is used to represent that group of wells. There has been a dramatic decrease in the percentage of wells in the DJ Basin that fall into the lowest rate type curve, and there has been an increase in the wells in the two highest rate groups. A similar trend can be seen in the PRB, where the number of wells in the low rate group are decreasing while those in the high rate group are increasing.

The production history and forecasts by basin are derived from the history-matched type curves, the historical well counts and the well count forecast. The rapid growth in the DJ Basin can be seen in Figure 9 where production more than doubled between 2011 and 2014. This rapid growth rate will slow for the next two years because of low oil prices. Oil production in the DJ Basin is forecast to be flat in 2015 and 2016 and begin to grow again in 2017. The play also produces significant volumes of NGL. The volumes shown include ethane, though some of this component remains in the natural gas stream.

The PRB production growth has been even more striking than the DJ Basin, though starting at a smaller base. Production has nearly tripled since 2011. Most of this growth has come from newer horizontal wells that were completed with multistage fracks. The forecast indicates a slowdown in growth from the play, again because of low oil prices. The growth rate increases again after 2016 but is not expected to reach the growth rates seen in the past three years. ■

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For more details on the Bakken and Niobrara shales, consult the selected sources below.

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Associate Editor

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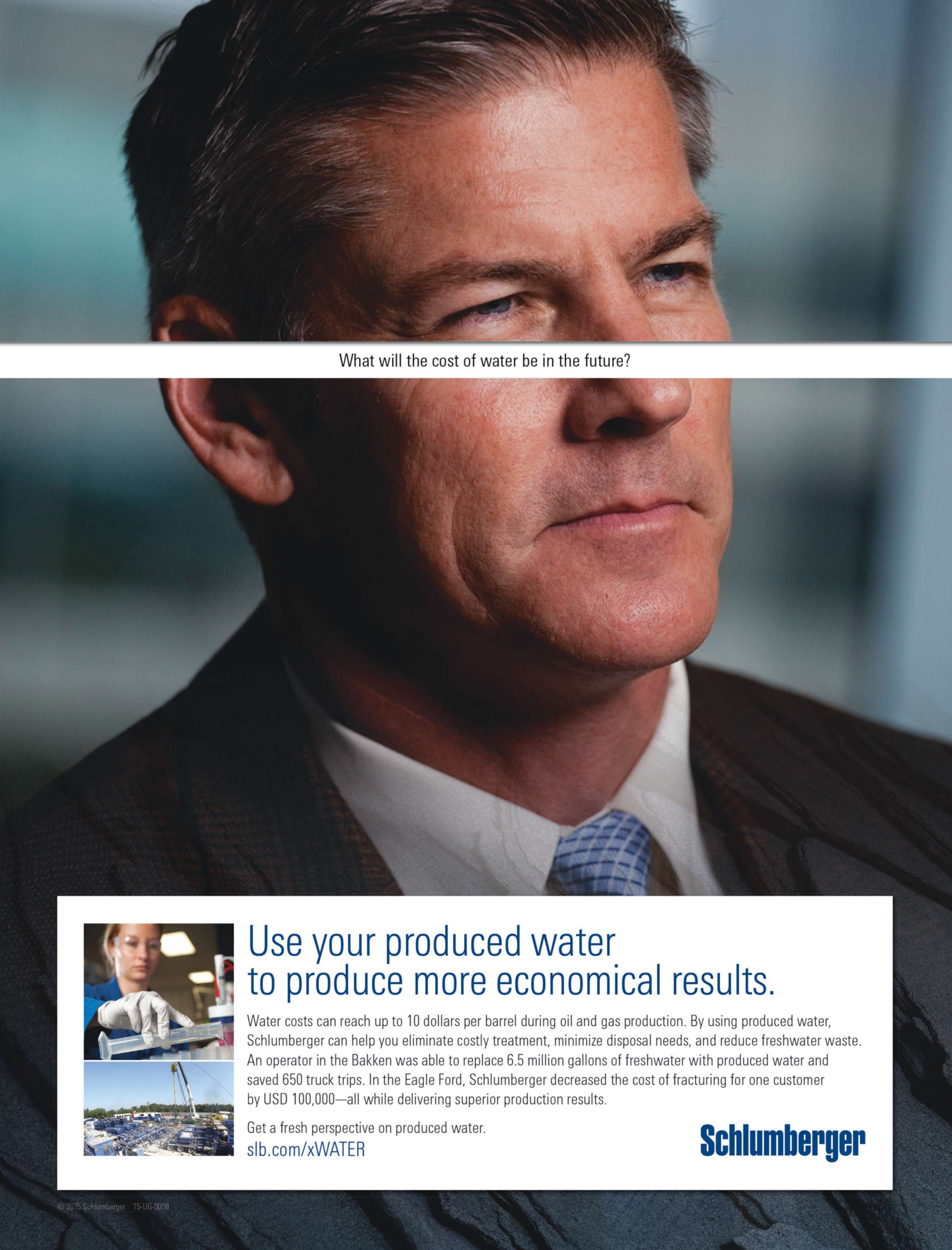
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