COLUMN

Geologic aspects of naturally fractured reservoirs

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Most of today's producing naturally fractured reservoirs were discovered accidentally; they were found by somebody who was looking for some other type of reservoir. That is one reason we should revisit the subject of how to explore for these reservoirs. Another is because (I am convinced) significant volumes of hydrocarbons reside in these reservoirs—particularly in fields abandoned because of improper testing and evaluation or because the wells did not intersect the natural fractures.

Unfortunately, rules of thumb and naturally fractured reservoirs do not mix well. What appears to work in one might fail miserably in the next. Consequently, each naturally fractured reservoir exploration play must be an individual research project.

This article discusses selected geologic aspects that describe, mostly qualitatively, key characteristics of the fractures and the places they are important in hydrocarbon production. The quantification of this material will be the subject of a future article.

Much of this material is treated in greater detail in the second edition of my book *Naturally Fractured Reservoirs* (PennWell, 1995). These concepts also reflect the interaction I had with David Stearns, Melvin Friedman, and Ron Nelson while annually presenting AAPG's Fracture Reservoir School from 1984 to 1996. I have also benefited from discussions in recent years with Duncan McNaughton. Although you will see them cited in the text and in the suggested reading list, I am solely responsible for the way in which these concepts are presented here.

Background. Stearns defines a natural fracture as a macroscopic planar discontinuity that results from stresses that exceed the rupture strength of the rock. Nelson defines it as a naturally occurring macroscopic planar discontinuity in rock due to deformation or physical diagenesis.

It follows that a naturally fractured reservoir is a reservoir that contains fractures that result from natural, as opposed to man-made, stress differences that existed in the rock at the time it fractured. These natural fractures can have a positive, neutral, or negative effect on fluid flow.

Open fractures that are uncemented might have, for example, a positive effect on oil flow but a negative effect on water or gas flow due to coning. These fractures tend to close as reservoirs are depleted due to increases in net normal stresses across the fractures. Not taking this closure or partial closure into account can lead to overly optimistic forecasts of reservoir performance.

It is, therefore, of paramount importance to have knowledge of magnitude and direction of in-situ principal stresses; azimuth, dip, spacing, and aperture of fractures; and a good idea with respect to fracture porosity and permeability. Partially mineralized fractures might provide better ultimate hydrocarbon recovery because the partial mineralization can act as a natural proppant, thus keeping the fracture open during depletion.

Totally mineralized natural fractures, on the other hand, could create permeability barriers to all types of flow. This could generate small compartments within the reservoir and, in turn, uneconomic or marginal recovery.

In my opinion, virtually all reservoirs contain at least some natural fractures. However, if the effect of these fractures on fluid flow is negligible, the reservoir can be treated (from a geologic and a reservoir engineering point of view) as a "conventional" reservoir. In this I agree with Nelson and regard only those reservoirs in which the fractures have an effect (either positive or negative) on fluid flow as naturally fractured.

Reservoir rock, by definition, must be porous and permeable. However, contributions to total porosity and permeability by the matrix and by the fractures must be separated. Therefore, precise determination of both matrix and fracture porosity, and matrix and fracture hydrocarbon saturation is important to accurately calculate the distribution between matrix and fractures of in-place hydrocarbons. Matrix and fracture permeabilities are equally important parameters for calculating true flow capacities.

Igneous, sedimentary, or metamorphic rocks can, under the right conditions, be the origin of acceptable reservoir rock. Although, most hydrocarbon accumulations occur in sandstones or carbonate rocks, I have evaluated commercial fractured reservoirs in shales, anhydrites, coal seams, sandstones, limestones, dolomites, volcanics, and igneous metamorphic reservoirs. Naturally fractured reservoirs can be found in all types of traps, all over the world, and throughout the stratigraphic column.

Secondary porosity. Secondary porosity (also known as induced porosity) is the product of geologic processes occurring after deposition and has no direct relation to the form of the sedimentary particles. Secondary porosity can be due to solution, recrystallization, dolomitization, or fractures.

Most fracture porosities reported in the literature range between about 0.01 and 10%. However, it is important to emphasize that fracture porosity is strongly scale-dependent. For example, if a 20-ft drilling break is encountered, the fracture porosity within those 20 ft is 100%.

The vast majority of papers and books on this subject discuss only fractures with apertures of a few microns. This is probably because of very poor core recovery from reservoirs containing fractures with much greater apertures. This has led to the generally accepted concept that, in naturally fractured reservoirs, the matrix provides the hydrocarbon storage while the fractures provide the necessary permeability for commercial hydrocarbon production but very little of the storage. However, this is not necessarily the case. I have seen fracture apertures in cores of up to 1 inch (or more) where the fractures are propped by partial mineralization. I am familiar with many reservoirs where natural fractures contribute to significant amounts of hydrocarbon storage, in addition to permeability.

Throughout the last 22 years I

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have used with reasonable success an ABC storage classification published originally by McNaughton (1975). Reservoirs of Type A have high storage capacity in the matrix and low storage capacity in the fractures, reservoirs of Type B have about equal storage capacity in matrix and fractures, and in reservoirs of Type C the storage capacity is entirely in the fractures.

Fracture generation and form. Fractures result from various causes. Landes and Nelson list them as:

- Structural deformation associated with folding and faulting. Faulting tends to generate cracks along the fault line which, in turn, produces a zone of dilatancy. Dilatancy is probably responsible for a large part of the migration and accumulation of petroleum in fracture reservoirs.
- Rapid and deep erosion of overburden that permits expansion, uplift, and fracturing along planes of weakness.
- Volume shrinkage due to such events as: dewatering in shales, cooling of igneous rocks, or desiccation in sedimentary rocks.
- Paleokarstification and solution collapse.
- Fracturing through release of high pore-fluid pressure (those that approach the lithostatic pressure) in geopressured sedimentary strata.
- The rare meteorite impact that causes complex, extensively brecciated, fractured reservoirs.

Fracture morphology relates to the characteristics and / or filling along natural fracture surfaces. Nelson says fracture morphology can be considered as open, deformed, mineral-filled, or vuggy.

Open fractures are uncemented and do not contain any secondary mineralization; i.e., there has been no alteration of the original fracture surface. Fracture width is usually very small, probably no larger than one pore diameter, but such fractures increase the matrix permeability significantly in a direction parallel to fracture strike(s). On the other hand, open fractures have negligible effect on permeability perpendicular to fracture strike(s).

Although there are exceptions, porosity of open fractures is usually a fraction of a percent.

Deformed fractures include gouge-filled fractures and slickensided fractures. The gouge is composed of the finely abraded material resulting from grinding or sliding motion that occurred along shear fractures in friable rocks. Gouge drastically reduces fracture permeability. A slickenside is the result of frictional sliding along a fracture (small fault) plane that polished the fracture surface. A polished, striated surface along fractures may increase permeability parallel to the fracture, but it also drastically reduces permeability perpendicular to the fracture. Slickensides, as well as gouge filling, can cause strong permeability anisotropy to develop in an otherwise isotropic reservoir.

Mineral-filled fractures are filled, or partially filled, with postfracture formation mineralization (most commonly quartz or calcite). Completely filled fractures can be formidable permeability barriers. On the other hand, partial fracture filling (mineralization) could have positive effects on hydrocarbon recovery because the secondary minerals could act as natural proppants. The strong calcite or quartz prevents fracture closure as the reservoir is depleted. I have seen apertures of partially mineralized fractures in cores of up to 1 inch.

Fractures along which vugs have developed can provide significant reservoir porosity and permeability. Because of their irregular and somewhat round shape, vuggy fractures probably do not close as the reservoir is depleted. Vuggy fractures usually result from acid waters percolating through fractures. In the extreme, such processes can lead to the development of karst and, therefore, very prolific reservoirs.

Permeability. Reservoir engineers refer to matrix permeability as “primary” permeability and use the term “secondary” permeability when referring to that portion of the total permeability that results from fractures and / or solution.

The presence of unhealed, uncemented, open fractures can greatly increase the secondary, and therefore the total, permeability of a rock. It is important to remember that as in the case of fracture porosity, fracture permeability is also strongly scale-dependent. For example, if fracture width (w_o) is expressed in inches, the intrinsic permeability of the fracture in darcys is given by:

$$k_f = 54 \times 10^6 w_o^2 \text{ darcys}$$

Consequently, the intrinsic permeability attached to single-point properties of a fracture opening 0.01 in. wide would be 5400 darcys or 5 400 000 md. These extremely high values of permeability clearly indicate the importance of fractures on production of tight reservoirs which otherwise would be noncommercial, even in the presence of high hydrocarbon saturations. The higher fracture permeability only exists parallel to the strike of the fractures while permeability perpendicular to fracture strike would be approximately equal to the matrix permeability.

Fracture permeability (k_f) from the above equation is attached to single-point properties. It can be extended to fracture permeability (k_2) attached to bulk properties of the system for one set of parallel fractures by using the equation

$$k_2 = k_f w_o / D$$

where D is distance between fractures. For the above example in which kf was 5400 darcys, if fracture spacing (D) is 12 inches, the k_2 fracture permeability would be 4.5 darcys (4500 md).

Mechanical behavior of rock. It has long been recognized that the mechanical properties of rocks are controlled by the combined influence of intrinsic and environmental parameters.

Intrinsic rock parameters include such things as composition, grain size, matrix porosity and permeability, bed thickness, and pre-existing mechanical discontinuities. Environmental properties include effective confining pressure (the difference between lithostatic and pore fluid pressure), temperature, time (strain rate), differential stress, and perhaps even pore fluid composition.

If environmental parameters are constant, rock composition basically determines the strength and ductility of various rock types. This obviously influences how difficult or easy it is to fracture the rock. Everything being equal, based on composition alone, the lithology most susceptible to fracture is quartzite followed in descending order by dolomite, quartz-cemented sandstone, calcite-cemented sandstone, and limestone.

Studies on the effect of grain size on fracture abundance have found, in general, that the finer the grain size the greater the strength, the lower the ductility and, therefore, the greater the fracture intensity.

In like manner laboratory studies

of the effect of matrix porosity have shown that the lower the porosity, the greater the fracture intensity in a given rock type.

Bed thickness also influences fracture spacing. Both outcrop and production data show that thinner beds contain more closely spaced fractures.

Environmental properties include effective pressure, temperature, strain rate, differential stress, and pore fluid composition.

Effective or confining pressure plays an important role in rock behavior and, therefore, in the generation of fractures. It has been demonstrated experimentally that rock strength and ductility increase with increasing effective pressure. Consequently, rocks deformed at shallower depths might be more fractured than the same rocks deformed under large overburden pressure.

Strain rate at which deformation occurred can be an important environmental parameter. In general, as the strain rate gets higher, rocks become increasingly brittle. However, to be an important parameter, strain rates must change several orders of magnitude. For example, rocks deformed by meteorite impact would be significantly more fractured than if deformed by slow tectonic deformation. However, rocks that were influenced by unexceptional strain rate variations within a long-term geologic process probably do not vary a great deal in fracture development.

Classification. Stearns and Nelson, from a geologic point of view, have classified natural fractures as tectonic, regional, and diagenetic.

Tectonic fractures. These were described by Stearns and Nelson as: "Those whose origin can, on the basis of orientation, distribution, and morphology, be attributed to or be associated with, a local tectonic event." The vast majority of all tectonic fractures fall into one of two categories: fractures caused by folding processes and fractures caused by faulting processes.

Fractures associated with faults can result from the same far-field stress differences that caused the faulting. Consequently, shear fractures can be considered miniatures of the fault, and their two orientations can be determined from the attitude of the controlling fault.

According to Stearns, and several other researchers, fractures associated with folds are genetically related to the folding process not to the regional stresses that caused the folding (as are fractures associated with faults). These fractures mostly form in response to bending stresses generated within individual folds. Stearns discusses four different conjugate fracture sets (Types 1, 2, 3a, and 3b) that commonly develop during the folding of layered rocks. Each of the four sets results from individual secondary stress states that are produced by the bending of plates and, therefore, produce several different orientations of both extension and shear fractures.

For what are termed Type 1 fractures σ_1, is parallel to bed dip, σ_3 is parallel to bed strike, and σ_1 and σ_3 are both in the bedding plane. In Type 2 fractures, σ_1 and or σ_3 both remain in the bedding plane, but it is σ_1 that is parallel to strike, and σ_3 is parallel to the dip direction. Type 3a fractures indicate an σ_1 perpendicular to the bedding plane and σ_2 parallel to bed strike. Type 3b fractures display an σ_2 parallel to bed strike and σ_3 perpendicular to the bedding plane. (In this article, subscripts 1, 2, and 3 refer to the largest, intermediate, and least principal stress, respectively.)

Although outcrop data has provided most of our information concerning tectonic fractures, these data are sometimes suspect because of weathering and stress relaxation.

Tectonic fractures are the most important fracture type with respect to hydrocarbon production. Numerous reservoirs produce from tectonic fractures, including the Palm Valley gas field of Central Australia, Aguarague gas field of Argentina, and offshore oil reservoirs of Mexico.

Regional fractures. They have been defined by Nelson and Stearns as "those (fractures) which are developed over large areas of the earth's crust with relatively little change in orientation, show no evidence of offset across the fracture plane, and are always perpendicular to major bedding surfaces." These fractures seem unrelated to local structures, are probably due to surface forces, tend to develop in an orthogonal pattern, and seem almost omnipresent.

Orientation of regional fractures remains constant within 10-15° over 100 miles. Because there is no offset across the fracture plane, there is no host rock damage which makes regional fractures very conducive to fluid flow. Good examples of regional fractures are in the Uinta Basin, approximately a fourth of the Colorado Plateau, and the entire Michigan Basin. Reservoirs producing from regional fractures are the Austin Chalk, the Big Sandy Field in eastern Kentucky and West Virginia (which produces from Devonian shales), the Spraberry Field in west Texas (which produces from fractured sandstones and siltstones), and the Altamont-Blue Bell Field in Utah (which produces from fractured sandstones). In some cases regional fractures are superimposed on tectonic fractures which can result in excellent production.

Diagenetic fractures. These form due to diagenetic changes in the rock. Most commonly they are (1) desiccation, (2) syneresis, (3) thermal gradients, and (4) mineral phase changes. Each of these processes or conditions can produce stress differences large enough to cause tensile, or extension, fractures associated with a reduction in bulk volume during diagenesis.

They are initiated by body rather than surface forces; i.e., they are started by forces in the body rather than external to it as is the case for tectonic fractures. An example of contractional fractures is the Permian Council Grove Formation of the Panoma Field (Kansas).

Undiscovered naturally fractured reservoirs, why and how? Many naturally fractured reservoirs should have been economic but were abandoned because of (1) incorrect pressure extrapolations, (2) poor completions, and / or (3) failure of the borehole to intersect the natural fractures.

Incorrect pressure extrapolations in fractured reservoirs might occur if the infinite acting radial flow period is not reached during a pressure transient test. This can lead to the erroneous conclusion that the reservoir is depleting.

Conventional completions are typically performed in intervals that meet certain porosity, permeability, and water saturation cutoff criteria. This is risky in naturally fractured reservoirs where the largest degree of natural fracturing could be associated with the lowest porosities and matrix permeabilities. Furthermore, there are instances where the largest fracture intensity is found in the thinner beds.

Commercial production of hydrocarbons is not possible from an unfractured, tight matrix. However, hydrocarbons can flow very efficiently from the tight matrix into the natural fractures. One key to success is to ensure fractures with high dips are intersected by directional or horizontal wells.

DSTs and RFTs are powerful techniques, but care must be exercised in their interpretation because they are not fully diagnostic in naturally fractured reservoirs. For example, if only the tight matrix is tested, these tools will correctly indicate very low permeability and no flow capabilities. Even when a fracture is tested, recovery may be only mud lost into the fractures during drilling operations.

Most natural fractures of commercial importance are vertical or near vertical. Therefore vertical wells do not stand the same probability of success as directional or horizontal wells in naturally fractured reservoirs.

For example, many years ago three unsuccessful vertical wells were drilled and hydraulically fractured in the Dilly Field in the Austin Chalk. The leases were dropped in 1979. However, more recently, two horizontal wells were drilled in the same general area. McNaughton states: "Both wells had roughly 3000 foot horizontal transects in the chalk. Well A was drilled at an acute angle (25°), and well B was drilled at a high angle (90°) to my estimated trend (NE-SW) of open fractures in the Dilly area. Well A and well B have produced about the same gross revenues, but well A has been producing for about two months longer than B. Thus, from this very limited production history, well B appears to be the better well."

Summary and conclusions. There is no doubt that natural fractures are a contributing factor in most reservoirs and virtually all structural traps. However, in too many cases they are ignored or, at best, only given token consideration. There is today a substantial database for predicting both fracture intensity and fracture orientation.

Furthermore, specific detection of fractures from modern log suites and / or well test data is now possible. Combine our ability to predict fracture orientation and spacing with our ability to measure fractured reservoir in situ properties with our ability to control directional drilling, and it becomes obvious that greater attention must be paid to the natural fractures in our reservoir rocks.

Only if we do begin to utilize all fracture data will we then begin to optimize our profit margin from fractured reservoirs, and most reservoirs are fractured.

Suggestions for further reading.
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