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FRACTURE PERMEABILITY IN CRETACEOUS ROCKS OF THE SAN JUAN BASIN

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INTRODUCTION

A single, 1-mm (1/25-in.)-wide fracture crossing a well bore in an oil reservoir can, by itself, provide permeability sufficient to produce between 7,000 and 10,000 barrels of oil per day, depending upon pressure and oil viscosity (Daniel, 1954).

Oil production from Cretaceous rocks is primarily, if not entirely, from fracture permeability in the Verde, Boulder, West Puerto Chiquito and East Puerto Chiquito fields along the margins of the San Juan Basin (Arnold, 1974). In many other producing areas in the San Juan Basin, reservoir permeability is aided by fractures.

The principal factors involved in development of fracture permeability are the radius of curvature during flexure folding, rock type, temperature, confining pressure and rate of strain. Open fractures tend to develop where tensional joints form at places of maximum curvature of beds (i.e., where there is greatest rate of change of dip, not necessarily where the dips are steepest). Fractures on the concave sides (from above) are likely to be tight, whereas those on convex sides of folds tend to be open, although the evidence is not conclusive. The following sequence is generally in order of increasing ductility and, therefore, decreasing brittle behavior: quartzite, dolomite, sandstone, limestone and shale (Stearns and Friedman, 1972). Bedding thickness influences competence; Harris and others (1960) suggested that density of joints is greater in thin beds.

Among the critical questions concerning fracture permeability are the following: When and how did the fractures originate? Are they of regional extent or confined to local structures? Are the original fracture trends in older rocks propagated upward into younger strata? When did hydrocarbons migrate into the fractures? And how might fractures in the subsurface be predicted in exploration?

Although we do not have all the answers, we hope to stimulate interest through a discussion of our observations and interpretations of subsurface data from the Verde and East and West Puerto Chiquito fields and surface work on the eastern edge of the San Juan Basin. Work on the Verde field is by Gorham, on the Puerto Chiquito fields by Greer, and on the surface by Woodward and Callender.

Speer (1957) discussed the Verde field during the early stage of development and reached some conclusions that are in part contrary to those expressed in this paper.

VERDE OIL FIELD

The Verde discovery well was drilled in the SE¼ sec. 14, T. 31 N., R. 15 W., N.M.P.M., and was completed in September 1955. The initial test was a random (?) wildcat guided by surface and subsurface geology to evaluate the Gallup Sandstone reservoirs recently discovered in the Horseshoe Canyon field, a combination(?) trap 8 mi to the southwest. Although only siltstone and indurated black shale were encountered in the so-called Gallup section, pipe was set as a result of shows and lost circulation and the well was completed, pumping 180 barrels of 42° API gravity oil per day. During the following three years, 100 wells were drilled and completed in the producing interval by various operators having a spacing of 40 to 80 acres per well.

Stratigraphy

Cretaceous rocks of the San Juan Basin are described elsewhere in this volume by C. M. Molenaar; therefore, only a brief summary of the stratigraphic sequence (fig. 1) other than that of the producing interval is given here. Rocks exposed in the field area are Upper Cretaceous formations, which consist of the Cliff House Sandstone (uppermost unit of the Mesaverde Group) in the northwest part of the field and a normal

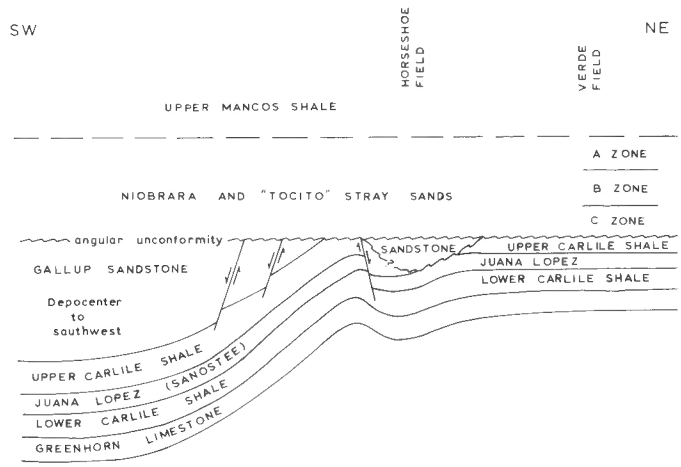

Figure 1. Diagrammatic cross section showing subsurface relations of Cretaceous rocks in the vicinity of the Verde field, northern San Juan Basin.

sequence of younger Cretaceous beds culminating with the Fruitland Formation to the southeast.

In the Verde field, the producing interval has mistakenly been identified as the Gallup Sandstone, whereas the field produces primarily from the Niobrara and is a fractured reservoir having no known effective porosity or permeability, except that associated with fractures, in the entire Niobrara-Carlile section. The producing zone is not exposed at the surface in the field area. The Niobrara interval consists of black, hard, indurated, fissile, calcareous marine shale and thin, hard quartzitic siltstone beds; the siltstone beds are located primarily at the base of the Niobrara, although they occur randomly throughout the interval. Subsurface samples and electric log correlations from the Horseshoe Canyon area indicate that the primary zone of interest in the Verde area includes the basal Niobrara, the Niobrara-Carlile unconformity, and the thin upper Carlile shale and siltstone interval above the Juana Lopez (Sanostee). A study of electric logs throughout the Verde area indicates that the primary producing interval is generally lithologically consistent throughout. No association is apparent between variations in siltstone content, calcite content, or other observable stratigraphic phenomena and quality of wells or oil reserves. The Niobrara interval of the lower Mancos Shale was subdivided by most operators into the A, B, and C zones, with the C zone being the basal zone of production (fig. 1). The overall A-B-C zone approaches 1,200 ft in thickness. The C zone was where most operators set pipe and then drilled open hole for 200-300 ft. With only a few exceptions, the bulk of the oil production was obtained from fractures in the C zone, which in turn had most of the siltstone interbeds. It is stressed that the C-zone lithology is generally consistent over the entire field area, which includes the peripheral dry holes. Therefore, the siltstone in the C zone, although important, cannot be the only factor controlling commercial oil production, as is discussed below.

Structure

The Verde field is located on the Hogback monocline on the northwest flank of the San Juan Basin in T. 30 and 31 N., R. 14 and 15 W., N.M.P.M., San Juan County, New Mexico. Surface dips are essentially to the south and southeast, with amplitudes ranging from 4 or 5 degrees in the Cliff House Sandstone in the northwest part of the field to 23 and 25 degrees in the southeast part of the field, where the Pictured Cliffs Sandstone is exposed as a hogback. The monocline is sinuous here, because it is folded to form a south-plunging syncline-anticline pair (fig. 2).

Evidence that the field is a fractured reservoir is simple, complete and conclusive. At the insistence of N. E. Maxwell, Jr., production manager and chief petroleum engineer of Pubco Petroleum, a core of the producing interval in one of Pubco's wells was obtained. The well selected was in the area of maximum flexure in the NW¼ sec. 30, T. 30 N., R. 14 W. Maxwell was convinced that the Verde production was attributable primarily to indigenous porosity and permeability in the siltstone stringers encountered in the pay section. After production casing was set on top of the C zone and cemented in place, the well was drilled with oil 15 ft below the casing shoe and the core barrel was put on. Forty-two feet of core was cut and recovered; it consisted of hard, indurated, fissile black shale with intercalated hard, quartzitic siltstone beds that ranged from 1 inch to several feet in thickness. Analysis

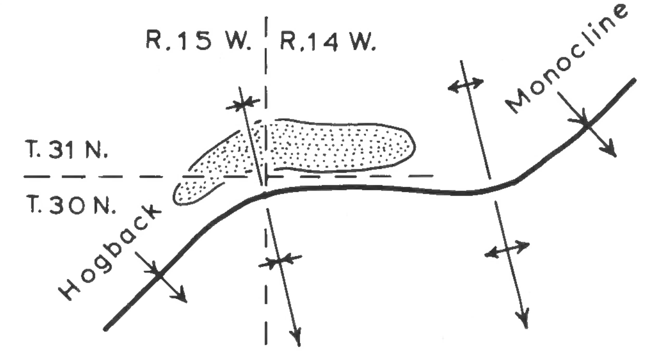

Figure 2. Generalized structure map of area of Verde field (stippled), modified from Hayes and Zapp (1955). **[Editor's note: for the structural relationship of this area to the entire basin, see paper by Woodward and Callender elsewhere in this volume.]**

of the siltstone in the shale matrix showed porosities and permeabilities far below that required to produce gas, much less oil.

To the author's astonishment, however, we have recovered "concrete" evidence of the fractured reservoir. There were no core-barrel-action fracture interpretation problems here. The entire core was laced in a dendritic pattern of fracture "casts" consisting of oil-well cement and lost-circulation material which had filled the natural fractures. Since coring had not begun until after drilling 15 ft below the casing shoe, we could conclude that in this zone one would not expect to obtain cement-filled fractures unless (1) production casing was set too low or in the fracture system and the cement dropped into the zone cored, or (2) not as likely, but still possible, the cement and lost-circulation material came from the adjacent lease operated by a major company that drilled through the producing zone, set casing, cemented and perforated. Incidentally, their wells, as a result of their completion practice, usually had initial potentials and ultimate production substantially lower than those wells completed by other operators who made open-hole completions. The fractures in the core, as represented by oil-well cement, measured in thickness from 1¾ in. wide to hairline cracks. The large fractures were either almost vertical or within 20 degrees of vertical; smaller fractures branched out from them in a festoon or dendritic pattern. One large fracture was represented by a cement slab 7½ ft long, 1½ in. thick, and equally thick from one side of the core to the other. Also surprising was the fact that almost the entire core was intact and being broken only at approximately 8- to 10-ft intervals by the drilling hands when it was removed from the core barrel.

Although poor to average production related to fracture permeability was determined in wells as far southwest as sec. 31, T. 31 N., R. 15 W., commercial production from fractures seems to disappear on the east edge of the field in sec. 22, T. 30 N., R. 14 W., perhaps due to loss of brittle interbeds. In our opinion the commercial oil-filled fractures are confined in large degree to areas of (1) maximum convex curvature, (2) rapid change in strike direction along the monocline from generally northeast to due east and back to the northeast on the eastern edge of the producing area, and (3) thin, brittle siltstone in an indurated Niobrara shale matrix. Of particular interest is the fact that the eastern edge of the field terminates on the crest of the plunging nose of the Barker Creek anticline, where most geologists would suspect strong fracturing. Field evidence from other areas (Harris and others, 1960; Stearns and Friedman, 1972) indicates that the strongest fracturing is located on the flanks of the folds and not on the crests of the anticlines or the troughs of the synclines.

An isoproduction or potential map drawn on the Verde field shows that the best wells (over 100 BOPD) are located mostly in the syncline crossing the hogback or at the major change in the strike of the hogback. Using the cross sections of Hayes and Zapp (1955), it can also be demonstrated that most production came from wells drilled near the Lewis Shale-Cliff House surface contact northwest of the steepest part of the monocline; upon reaching the C zone of the Niobrara, however, the best wells intersected the pay zone at the greatest angle of curvature, or about halfway through the arc formed by the monocline at that level, assuming parallel folding. This structural position on the monocline appears to be the most important empirical relationship for the best production or fracture abundance. It should be pointed out, however, that the angle of incidence between the bore hole and the fracture system more nearly approaches 90° near the greatest angle of curvature, and thus more fractures will be encountered with the same depth of penetration. Next in importance is an abrupt change in strike of the producing zone, and third is the presence of brittle, thin beds of siliceous siltstone. Although the presence of these brittle rocks is mandatory for fracturing, they are present in varying degrees at the base of the Niobrara and are capped by overlying ductile soft shales throughout the Rocky Mountains. Most of the fractured shale reservoirs known to date are lithologically located near the contact or in the area of change of deposition from nearshore shale and siltstone stringers to marineward limestone-dolomite stringer facies.

The isopotential map of the field, based on reported initial potentials of the individual wells, depicts a tabular high-potential area about 4 mi long (east-west) and 1.5 mi wide (north-south), centered in sec. 29, T. 31 N., R. 14 W. This shape at first glance might indicate a possible direct association with siltstone or "reservoir" content. Although true in part, this high-potential area is more directly associated with its previously discussed structural position and, to a large degree, with well completion practices discussed below. Completion practices appear to have been particularly important in the vicinity of sec. 28, T. 31 N., R. 15 W., where low potentials are reported but where the better wells are located in the proper structural position.

Completion Practices

Operators in the field follow these methods: (1) set pipe on top of the fractured zone, drilled out with cable tools or with oil as drilling fluid and completed in open hole with tubing run to the base of the production string or near total depth in the open hole; (2) set pipe above the fractured zone as in (1), but ran a liner in the open hole with tubing set to total depth; or (3) set production casing through the fractured zone, cemented, then perforated.

Of the three methods described above or variations thereof, method (1) was by far the most satisfactory for this type of reservoir. Of particular interest was the observation that while drilling with cable tools through the oil-reservoir fracture zone and to total depth, little or no oil or fluid entry was noted on several of the interior locations. Following a modest or high oil fracture treatment (without sand), all of these wells had almost unlimited oil entry at casing swab rates exceeding several thousand barrels of oil per day. Since the initial bottom hole pressure permitted the oil, with little or no associated gas, to rise in the casing only to about 400 ft from the surface, all wells were completed by pumping with units designed to slightly exceed the allowable production, which was below 70 barrels per well per day. At least two hypotheses were advanced at the time as to why these wells had no fluid entry while drilling with cable tools in open hole, but had high fluid entry rates on being slightly treated. The first and perhaps the more plausible explanation was that, as demonstrated in one well, cement dropped below the guide shoe into the fracture system. Since its weight far exceeded bottom hole pressure, it thus temporarily plugged the fractures until artificially fractured. Another explanation was that cable tool drilling or rotary drilling with oil created a thin, impermeable plaster composed of drilling fluid and cuttings that had to be broken hydraulically. In any event, completion practice (1) usually resulted in excess of 100 percent increases in total production and initial potential compared to (3). Method (2), a variation of (1), was considered by some operators to be an improvement on (1) since subsequent caving was prevented; caving which could cause tubing to get stuck or might limit fluid entry. Our experience indicated that it was unnecessary, since the fractures in the indurated shales and siltstone stringers were in tension or could not have existed.

In this particular reservoir, no open hole clean-out problems occurred during the life of the wells, as long as the wells had initially been cleaned out properly. We were not aware of any particular benefits in expense savings or increased production as a result of setting a liner in the open hole. Completion practice (3), conventionally used in sandstone and carbonate reservoirs, had no application to this reservoir. In addition to large amounts of mud and lost-circulation material being plastered into the fractures while drilling, at completion the cementing process, in most cases, effectively sealed the fractures so that even after heavy or large fracturing only modest wells or dry holes resulted. These poor results may have been due in part to uncertainty as to the selection of perforated intervals, although the best fractures appeared to be associated with increases in resistivity amplitude or zones of greater siltstone content.

Reservoir Performance

The Verde field produced 7,474,136 barrels of 39° API sweet, paraffin-based crude oil prior to depletion. Pubco's two sections, located in the center of the field and in the high potential area, produced 952,533 barrels prior to depletion, or 744 barrels per acre. The reservoir behavior during production was a classic example of gravity drainage with only modest help from solution gas. As the field was produced, the structurally higher wells were depleted first and then the next line of wells, until the bottom tier was reached. Bottom hole pressures through the life of the field confirmed gravity drainage as the producing mechanism, with a steady pressure drop directly related to depletion. Although no interference tests were conducted, it was observed that almost the entire field depleted as a unit; the structurally higher wells were depleted first, followed tier by tier down dip until total-field depletion had occurred. Excellent overall fracture connection was thus proved, which had in fact been easily observed during initial development. Although the operators attempted to obtain 80-acre spacing, their request was not granted by the New Mexico Oil Conservation Commission and the field in part was developed on a 40-acre spacing pattern. In retrospect, had the field been developed along the structurally lower tiers of wells only, and perhaps spaced ¼ mi apart, the overall economics of the field would have been substantially better, and total oil recovery based on the reservoir behavior described above would probably have been identical.

EAST AND WEST PUERTO CHIQUITO FIELDS

In the course of the drilling of wells in the East and West Puerto Chiquito pools (T. 24-27 N., R. 1 W. and R. 1 E.), Rio Arriba County, New Mexico, Benson-Montin-Greer Drilling Corp. (B-M-G) obtained information and conducted a number of tests which revealed some interesting reservoir characteristics. These fields produce from fractured rocks in the Niobrara Member of the Mancos Shale. Brief summaries of the tests and conclusions are set out below, along with interpretations and hypotheses.

Commercial oil production resulted from wells drilled on a structural nose in the shallow (2,000- to 4,000-ft-deep) East Puerto Chiquito pool and along strike of the monocline with "synclinal-flexing" in the deeper (5,000 to 7,000 ft) West Puerto Chiquito pool. Both reservoirs are in areas of folds; our postulate is that folding caused the fracturing which resulted in reservoirs being sufficient for commercial production. London (1972) investigated the lithology of the producing interval in West Puerto Chiquito with particular emphasis on content of calcite and dolomite in the reservoir rock. London concluded that the percentage of dolomite, which is more brittle than calcite, can have significant effects on whether the rocks fracture. One might then draw the conclusion that a relatively high dolomite content is just as essential as flexure, or whatever other deformation might be partially responsible for the reservoir's existence.

General Reservoir Characteristics

Interpretation of test data, along with information from cores and logs, shows that the individual reservoirs are relatively thin; from the standpoint of oil production, the porosity is all fracture porosity; and each reservoir comprises individual fracture "blocks" of low permeability, but joined and interconnected to a high-capacity fracture system.

The greater part of the volume of the reservoir is probably formed by these fracture blocks and a relatively small part by the high-capacity connecting fracture system. Accordingly, in drilling a well, one may expect to penetrate not the fracture system but rather one of the fracture blocks. This is apparently what has happened in West Puerto Chiquito. Only some wells encounter natural production, and these natural-production rates have never been high enough to indicate direct communication with the high-capacity fracture system. Only after sand-fracture treatments connected the well bores to the fracture systems were wells capable of producing at high rates developed.

The reservoirs ("tight" blocks and high-capacity fracture system) are confined to relatively thin zones which are identifiable on electric logs as more resistant than surrounding beds. Although vertical fractures have been found in cores through these zones, they apparently do not continue far into the more plastic shales above or below. In the Verde field, in contrast, fractures extending for considerable vertical distances have been found. In the Puerto Chiquito fields, communication has been measured over long distances horizontally (miles), whereas vertical communication has not been found in beds as close as 100 ft apart. In fact, an absence of communication between zones in a single well bore has been determined. With minor exceptions, commercial production has been limited to zones which are not only electrically resistant, but which extend over long distances and can be correlated well to well.

Other, isolated zones have produced some oil, sometimes "natural" (without artificial fracturing), at initial rates as high as 20 BOPD; but generally these zones deplete rapidly and they are apparently not connected with commercial reservoirs. The presence or absence of these isolated zones does not have a relation to commercial productivity of the main identifiable commercial zones.

Three characteristic zones from which most of the production originates are found over the greater part of both East and West Puerto Chiquito fields. The main contributing zones in East Puerto Chiquito are the upper two ("A" and "B"); whereas in West Puerto Chiquito, most of the production in the south part of the pool is from the lower zone ("C"), with production in the north part from "A" and "B."

Well Spacing

Under a New Mexico Oil Conservation Commission order, in East Puerto Chiquito the spacing is 160 acres per well, and in West Puerto Chiquito it is 320 acres per well. However, in view of the extensive communication found in West Puerto Chiquito, the wells in the Canada Ojitos unit there (from which most of the production in West Puerto Chiquito originates) are more widely spaced. Pressure maintenance by gas injection has been continuously carried on since August 1968. Gas injection wells are located on the up dip side of the reservoir and oil recovery wells on the down dip side; the resultant spacing of the oil recovery wells is approximately one well per four sections. The wells appear to be efficiently draining these large areas; single well recoveries have exceeded 10 times the average recovery of wells in the nearby Boulder-Mancos pool, which was drilled on 80-acre spacing and which had much better reservoir characteristics and potential for production.

Oil-Producing Mechanism

B-M-G has attempted to take full advantage of the efficient gravity-drainage mechanism in producing its wells in both the East and West Puerto Chiquito pools. Because of the higher formation volume factor and consequent shrinkage, with its attendant adverse effects on recovery, pressure maintenance by gas injection was instituted for the West Puerto Chiquito oil. The main purpose of the gas injection was to maintain pressure so that the gravity-drainage mechanism could operate under optimum conditions. It was not intended to "sweep" the reservoir with gas.

To avoid channeling and to assure gravity drainage, the producing rates of the recovery wells were restricted considerably below their producing abilities. The "gravity-drainage potential" of the reservoir was estimated from interference tests and production rates were set accordingly. B-M-G considers the pressure maintenance operation to have been successful.

Pressure Build-Up, Draw Down and Interference Tests

A high degree of communication was found in wells in both the East and West Puerto Chiquito pools. On interference tests in West Puerto Chiquito, measurable pressure changes occurred in observation wells within 24 hours of commencement of production of wells as far as 1½ mi away. In East Puerto Chiquito, reservoir pressure increase caused by fracture treatment of a well was observed in an observation well 1 mi from the well being treated.

In West Puerto Chiquito overall reservoir transmissibilities were measured by interference tests to be in the range from 2 to 10 darcy-feet. Individual well transmissibilities were found to be much lower, however. Reasonable interpretation of the data permits only one conclusion as to general reservoir geometry: there is a series of individual "fracture blocks" with transmissibilities ranging from 0.02 to 0.4 darcy-feet which are connected as in a jigsaw puzzle through a high-capacity network. Areal sizes of the individual fracture blocks were calculated to be on the order of 30 to 70 acres.

Drainage of Tight Fracture Blocks

Because of the apparent geometry of the reservoir and the fact that a substantial amount of oil might be contained in the low-permeability fracture blocks, a question arises. Should an effort be made to deplete these fracture blocks as well as the high-capacity fracture system through gravity drainage? The answer depends on the rate at which oil can drain from these tight blocks and the economics of continuing gas injection. Since this determination cannot be made until the oil has first been produced from the high-capacity system, it cannot be made early in the life of the reservoir.

To answer this question, B-M-G continued to produce a suitable well (Canada Ojitos unit C-34) after the high-capacity system was essentially swept (gas to oil ratio (GOR) increased from an initial ratio of 300 to about 10,000). After reaching the 10,000 to 1 GOR, this well has produced approximately 100 BOPD for 3 years with no further increase in GOR. This suggests that if all of the fracture blocks in the reservoir are of this quality, it should be feasible to continue gas injection for some time after the main fracture system has been depleted (other wells have been shut-in when their GOR reached about 2,000 cubic feet per barrel).

Reservoir Volume

Per acre reservoir volume of fractured reservoirs is a difficult physical characteristic to measure. The only suitable means found by B-M-G was through analysis of interference tests. Two reliable interference tests were conducted, which, in conjunction with other data, placed a value of 1,500 to 2,000 barrels of oil per acre in place for the part of the reservoir influencing the tests (about 5,000 to 10,000 acres).

The first test was conducted at a time when the pressure was above the bubble point (oil was undersaturated), and for this test the accuracy of the calculation was limited by the indefinite volume of the compressibility of the fractured shale reservoir rock. From this test a range of 1,000 to 2,500 barrels of stock-tank oil per acre was estimated. At the time of the second interference test the pressure was below the bubble point, eliminating the error due to the indefinite value of the compressibility of the fractured shale since the compressibility of the oil was now much higher; this test showed 1,600 barrels per acre for approximately 2,000 to 3,000 acres of test area. This figure was estimated to be within 20% of the true value, which is considered close agreement for the two widely different conditions under which parts of the same reservoir were tested.

Undoubtedly a large part of the reservoir has a much lower volume of pore space per acre, as indicated by lower capacity wells. Data for these other areas are not available; we have been able to hypothesize only about their physical characteristics.

Recovery of the oil in place will depend on how much of the reservoir is susceptible to gravity drainage and whether proper advantage is taken of it. Recovery estimates range from 6% of oil in place for those parts of each reservoir produced through the solution-gas mechanism to ten times as much for the parts depleted by gravity drainage.

REGIONAL FRACTURE TRENDS

Joint trends in the San Juan Basin have not been quantitatively characterized in the literature. Kelley and Clinton (1960, p. 19-22) provided a regional perspective for fracture patterns of the Colorado Plateau. They concluded that the joints of the central San Juan Basin are heterogeneous, although northeast (N. 10° E. to N. 60° E.) and northwest (N. 15° W. to N. 75° W.) trends are most common, as they are in much of North America (Thomas, 1976). The predominant trend appears to be northeast, between N. 45° E. and N. 60° E. (Kelley and Clinton, 1960). Pervasive fracture trends of similar orientation have been described elsewhere in the Colorado Plateau by Kelley and Clinton (1960), Wise (1969), Shoemaker and others (1974), and Goetz and others (1975).

The major unsolved problems of many regional fracture analyses are the age of fracturing and the orientation of stress fields that produce fracturing. These questions remain unanswered for the San Juan Basin and are in large part beyond the scope of this paper. However, work by a number of investigators suggests that the following observations are important:

1. Precambrian foliation trends and age-province boundaries are predominantly northeastward beneath the San Juan Basin (Kelley, 1955; L. T. Silver, personal commun., 1977);
2. Northeast-trending fault zones with major displacements of Precambrian age have influenced later Phanerozoic fracture trends (Shoemaker and others, 1974); in a similar way, fracture sets of Precambrian age have been reactivated and extended into overlying sediments (J. M. Potter, written commun., 1977);
3. Laramide compression and right-shift of the Colorado Plateau (Woodward and Callender, this volume) probably generated both northeast-northwest conjugate joint sets and northeast-trending extensional fractures.
4. Neogene extension of the western United States (Atwater, 1970), which produced mainly north-trending fracture patterns, has not had a significant effect on fracture trends in the Colorado Plateau, excluding its margins; this is perhaps explained by the divergence of north trends from the basement grain of the region.

SURFACE OBSERVATIONS

In general joints that formed by compression in isotropic rocks are likely to intersect at about 60 degrees and to be closed or tight; joints created by tension tend to be parallel and open (de Sitter, 1956, p. 123-124). In a study of regional jointing in the Comb Ridge-Navajo Mountain area to the west of the San Juan Basin, Hodgson (1961) concluded that the joints there are not genetically related to folding, but form by a fatigue mechanism due to earth tides. Hodgson further suggested that joints form early in the history of the sediment and are produced in each layer of overlying rock as soon as it is strong enough to fracture; thus, the older joint trends control development of joints in younger strata.

Field studies of joints by Harris and others (1960) and Stearns and Friedman (1972) have shown that the density and orientation of joints in folded beds are directly related to where they occur on the folds (fig. 3); however, neither of these studies fully explained the origin of the joints. Thus, an empirical relationship exists that is useful in petroleum exploration, even though the mechanics are not fully understood.

Our observations of joints in surface exposures along the eastern side of the San Juan Basin indicate that joint trends in older rocks are not necessarily reflected in overlying strata and that regional joints are probably related to deformational events such as the Laramide orogeny and development of the late Cenozoic Rio Grande rift. Also, we do not find a consistent orientation of the joints with respect to bedding attitude, as suggested by Stearns and Friedman (1972).

We measured the orientations and density of joints in the Dakota Formation on a south-plunging anticline-syncline pair in the San Ysidro quadrangle (fig. 4), and our findings are briefly summarized as follows:

1. At any one place there are usually three sets of joints, and they are perpendicular to bedding.
2. Open joints trend parallel to the axis of the fold and occur in thick competent beds on the convex side of the fold. The implications of this fact are far reaching and merit further discussion. Crests of anticlines are not necessarily favorable places for open fractures to develop; the corollary is that synclines are not necessarily unfavorable places for open fractures to form if the convex side of the fold is considered.

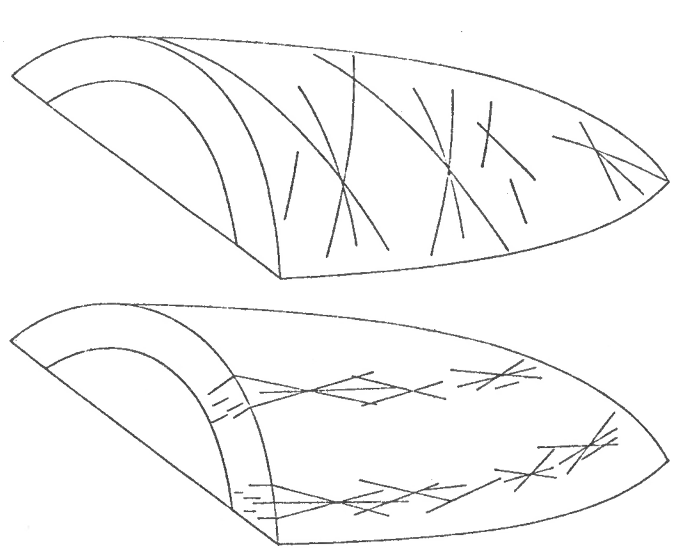

Figure 3. Diagram showing common fractures associated with folds, as noted by Stearns and Friedman (1972).

3. Dip joints or oblique joints are more commonly tight than are strike joints.
4. Density of joints is greatest in thin beds.

CONCLUSIONS

The Verde oil field, one of the first of its kind to be discovered in northwestern New Mexico, is a fracture-reservoir trap along a monoclinal flexure; it is lithologically controlled only to the extent that brittle competent interbeds capable of fracture are present.

The fracture reservoir, one of the earliest known trap and source mechanisms, was understandably, and for good reason, bypassed in favor of closed-structure and sandstone- and carbonate-reservoir exploration. The fact is that untested closed structural prospects in oil-producing basins are nearly a thing of the past. Exploration managers have jumped from closed structures to stratigraphic exploration with dismal results. There are, of course, exceptions, but when looking at the record of the industry as a whole, it is not surprising that some explorationists are advocating random grid exploration drilling of various magnitudes.

When exploring for fracture permeability, it should be kept in mind that fractures tend to be best developed where flexures have maximum curvature; if the axial surface of the fold is inclined, then the hinge will migrate laterally with depth. Open fractures are best developed parallel to the trend of the fold; therefore, monoclines or limbs of folds are attractive targets. Although fractures tend to be perpendicular to bedding, they have greater lateral than vertical continuity.

Monoclines are common along the margins of many basins in the Rocky Mountains; because of their locations along basin margins, they probably formed at relatively low confining pressures, thus facilitating fracture of brittle rock in the Cretaceous System. In view of the many hundreds of miles of monoclinal flexures exposed in Cretaceous rocks in basins of the Rocky Mountain region, a new look at this type of trap is surely warranted.

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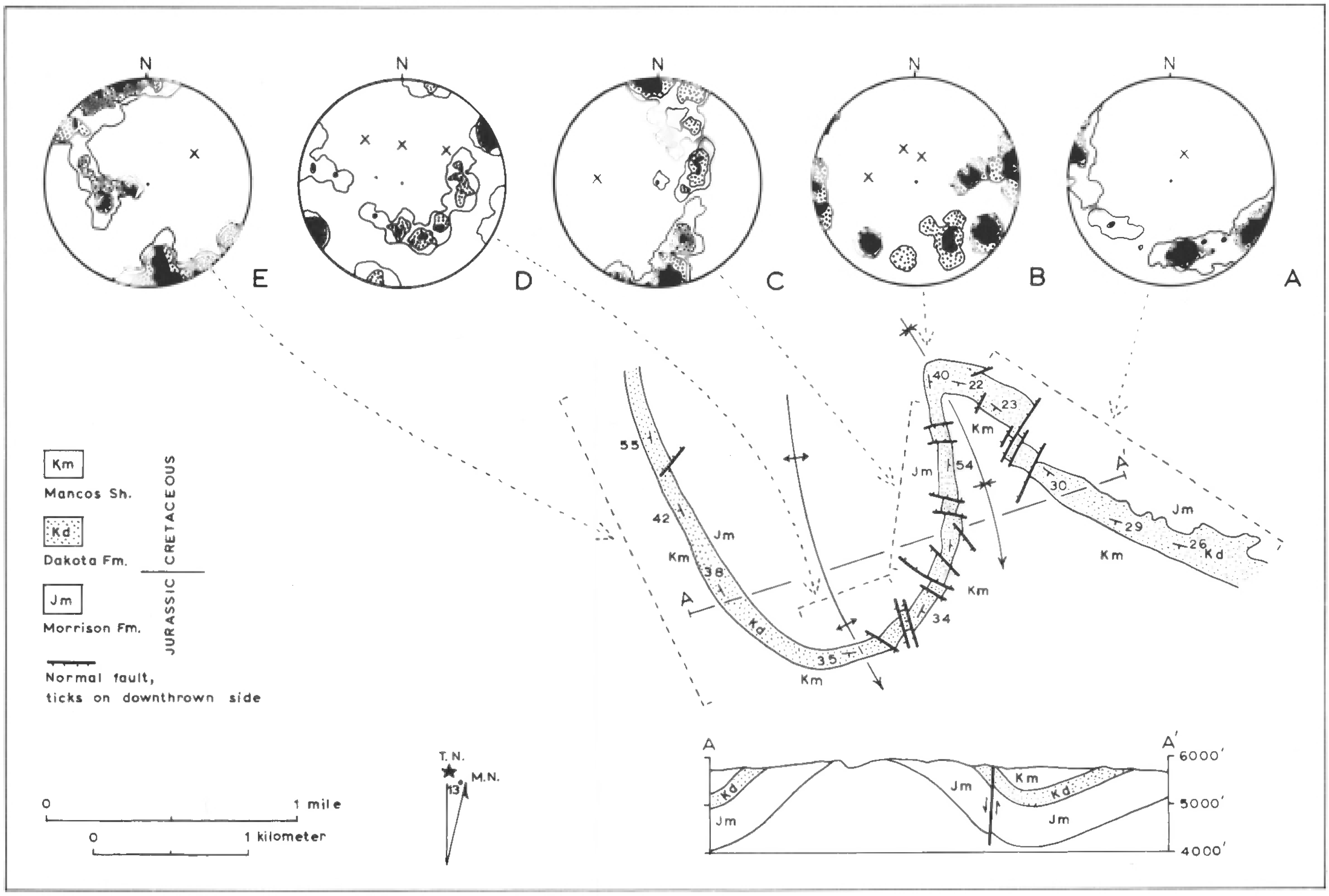

Figure 4. Generalized geologic map and structure section of Tierra Amarilla anticline, San Ysidro quadrangle, New Mexico (modified from Woodward and Ruetschilling, 1976), and Schmidt equal-area projections of poles to joints (X = average bedding; 10-11% (solid), 5-7% (stippled), 2-3% (outlined), per 1% area). Diagrams of joints constructed by computer plot (modified from Warner, 1969). A, 88 poles to joints; B, 18 poles to joints; C, 35 poles to joints; D, 28 poles to joints; E, 34 poles to joints.

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