UGR File #452
U.S.Dept.of Energy METC
Dec. 2, 1980

UGR FILE # 452

POSSIBLE INTERACTION BETWEEN THIN-SKINNED AND BASEMENT TECTONICS IN THE APPALACHIAN BASIN AND ITS BEARING ON EXPLORATION FOR FRACTURED RESERVOIRS IN THE DEVONIAN SHALE

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Abstract

The Devonian shale of the Appalachian Basin is an enormous, virtually untapped resource of natural gas. Production rates are low; even better wells are marginally economic. Most of the gas produced arrives at the wellbore via natural fractures; the direct contribution from the shale matrix, where most of the gas is held, is minimal. Hence, exploration for highly fractured areas within the shale is a most important aspect of the Department of Energy's Eastern Gas Shales Program. Fracture permeability is primarily the net result of jointing that occurred following consolidation. Jointing ideally occurs whenever fluid pore pressure exceeds the minimum compressive stress (σ_3) by the tensile strength (K) of the rock, provided $\sigma_1 - \sigma_3 \leq 4K$. Consequently, the formation of joints, which show evidence of being tension fractures, is not depth restricted (Secor, 1965). Carbonate mineralization of many natural fractures seen in Devonian shale core testifies to the role of fluids. Thus, joints, originating as natural hydraulic fractures, are oriented perpendicular to the prevailing σ_3 and provide a cumulative record of stress history. Were they exposed, it should be possible to unravel the tectonic history of the shale by establishing a relative chronology among sets. In practice, the explorationist must reverse the process. Using the tectonic histories of marginal areas and the underlying basement as boundary conditions, he is forced to synthesize a tectonic history for the Devonian shale and utilize it to predict ensuing joint patterns, from which he hopes to locate concentrated fracturing. Finite element stress analysis is a powerful technique for calculating stress trajectories and intensities, but ignorance of tectonic influences severely limits its application. Of particular significance are possible interactions between thin-skinned and basement tectonics.

Introduction

The purpose of this paper is threefold:

1. To introduce the reader to the U.S. Department of Energy's (DOE) Eastern Gas Shales Project (EGSP), which is the tacit incentive for this symposium and under the auspices of which these proceedings are being published.

2. To offer some fundamental insights on jointing in the Devonian shale from the point of view of rock mechanics.

3. To discuss how a growing understanding of the thin-skinned and basement tectonics of the Appalachian Basin should influence exploration for natural gas from the Devonian shale.

The common thread that unifies these seemingly disparate topics is natural fracture systems in the Devonian shale, the presence of which the authors judge to be critical to commercial natural gas production.

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Devonian Shale

Dwindling reserves of natural gas are an important aspect of the nation's energy crisis, but one, commonly overlooked with the current focus on scarce oil supplies. Yet, natural gas currently supplies about 30 percent of our national energy needs. Yearly consumption is about 20 tcf (trillion cubic feet). At projected rates of gas discovery, demand could outstrip domestic supply by 10 tcf per year or more by 1990. Consequently, unconventional resources of natural gas are receiving closer scrutiny than ever before. One such is the Devonian shale of the Appalachian, Illinois, and Michigan basins.

"Devonian shale" is the term drillers employ to refer to all fine clastic strata intervening between the lower Middle Devonian Onondaga Limestone and the Lower Mississippian Berea Sandstone, or their equivalents. Where it overlies the Berea, the dark Sunbury Shale is also included. Thus, the term comprises the bulk of the Devonian section in all three basins and includes some lower Mississippian strata as well. Figure 1 shows the wide distribution of Devonian shale across the eastern half of the United States. The thickness of the comprised section ranges within the Appalachian Basin from less than 1000 feet in the west to more than 7000 feet in the east; it is on the order of a few hundred feet in the other two basins. Because of their capacity to generate natural gas under favorable geological conditions, the dark, organic-rich shales are of particular economic interest; though, over much of the Appalachian Basin gray shale and coarser clastics dominate the section. The proportion of dark, organic shales varies from over 80 percent in the western basins to about 10 percent in the eastern portion of the Appalachian Basin. Where it crops out the Devonian shale has historically been subdivided into named stratigraphic units. Some of the more familiar names are Hamilton, Marcellus, Chattanooga, Ohio, New Albany, Antrim, etc.

Resource Potential

Despite its novelty as an important unconventional resource of natural gas, commercial Devonian shale gas production is as old as the industry itself. Fredonia, NY, 1821, the first gas well drilled in the United States produced from Devonian shale at a depth of 27 feet. Subsequently, natural gas for local consumption has been profitably extracted from hundreds of Devonian shale wells drilled to depths of a few hundred feet along the southern shore of Lake Erie. In the more than 150 years that have elapsed since the drilling of the first Devonian shale gas well, commercial gas production from Devonian shale has been established from scattered areas in all three basins. Big Sandy, the largest Devonian shale gas field (also the largest gas field in the eastern United States), covers most of eastern Kentucky and includes parts of West Virginia, Virginia, and Ohio.

Yet, natural gas from Devonian shale constitutes but the minutest fraction of the total consumed in the United States. Commercial gas producers have never considered the shale to be a prime drilling target to be compared with the traditional sandstone and carbonate reservoirs, but only marginally economic at best. The reason becomes evident upon comparing production decline curves (figure 2). The rate of production from wells completed in conventional reservoirs is initially much higher, often by an order of magnitude, than from those completed in the Devonian shale. The rate of production decline, however, tends to be much less for Devonian shale wells than for sandstone or carbonate wells. Although cumulative production from Devonian shale wells may ultimately exceed that from conventional wells, the relatively long payout time and low annual return on investment makes the former economically unattractive relative to the latter. Regulated gas prices coupled with high inflation aggravate the situation.

Nevertheless, the Devonian shale is an enormous resource of natural gas, as yet virtually untapped. Up to 15 cubic feet of gas may be contained in a ton of black shale. Estimates of total gas-in-place vary from 300 to 900 tcf, and these may be conservative by a factor of two or three. More important and more difficult to estimate is the amount of gas economically recoverable from the Devonian shale. That depends on a number of largely imponderable factors, such as future price and unforeseen technological advances. Estimates have ranged widely from a very pessimistic 10 tcf to a very optimistic 500 tcf. A couple of hundred trillion cubic feet (tcf) would appear to be a reasonable compromise, but that is equivalent to a decade's gas supply at current consumption rates. Total historic production is estimated to have been about 3 tcf.

Expansion of Devonian shale gas reserves within the confines of the total resource is dependent on three factors: economics, technology, and geology (figure 3). Simply stated, economics equals price. The higher the wellhead price of gas, the greater will be the incentive to drill the Devonian shale, even in the face of low production rates. Extraction technology is critical to exploiting the shale, as most Devonian shale wells produce negligible quantities of gas prior to stimulation. Geology or, more precisely, the exploration for environments favorable to the production of gas from the Devonian shale is the object of this paper and, indeed, this symposium.

The U.S. Department of Energy's (DOE) Eastern Gas Shales Project (EGSP) was initiated in 1976 and now continues as an integral part of its nationwide Unconventional Gas Recovery Program. The EGSP aims to promote further commercial development of natural gas supplies from the Devonian shale. It has two principal emphases that essentially correspond to two of the above-mentioned factors on which shale gas reserves depend: Resource Characterization and Evaluation (Geology) and Extraction Technology Development, Testing, and Verification (Technology). Responsibility for the third factor (Economics) falls outside the scope of the project; that belongs to the regulatory arm of DOE. Exploration Research and Development is an important ongoing activity under Resource Characterization and Evaluation. It represents the practical application of resource quality information to the selection of optimum areas, and even sites, for extraction technology demonstration projects. The goal of this symposium is to illumine the tectonics of the Appalachian foreland in such a way as to reveal promising exploration rationales for the Devonian shale.

Production from Fractured Reservoirs

In driller's parlance the Devonian shale is an extremely "tight" formation, meaning that natural gas does not easily flow to the wellbore as it does in some of the more permeable sandstone reservoirs. In fact, the matrix permeability of the shale is so low that it is measurable only in fractions of a microdarcy (Smith, 1978). R. D. Smith (personal communication) estimated that it takes perhaps 30 years or more for a molecule of gas to move through one centimeter of shale under the impetus of the pressure gradient existing in a typical Devonian shale well. Matrix permeability alone is thus not anywhere near sufficient to account for existing Devonian shale production. No known means of artificial stimulation is capable of inducing gas production from a formation with such a low matrix permeability, if that is the only avenue available for gas transport. Matrix permeability that low is presumptive evidence that where the shale produces natural gas the total formation permeability must be very greatly enhanced by natural fractures. Fractures provide additional surface area through which to drain large volumes of matrix, albeit slowly, and act as conduits leading eventually to the wellbore.

Other evidence and lines of reasoning also yield the conclusion that Devonian shale production is from fractured reservoirs. Figure 4 compares average production decline curves for Devonian shale wells differentiated according to open flow (i.e., initial open flow after stimulation). There is a high degree of variability in the performance of Devonian shale wells, but, a consistency in the pattern of decline. Wells with high initial production decline rapidly during the first several years of production, but then they progressively level off, eventually reaching a near steady-state with an imperceptible rate of decline. Wells with low initial production decline very little, but reach the near steady-state early in life. The higher the initial production, the higher will be the level of the near steady-state production. Devonian shale wells commonly display hyperbolic production decline, as opposed to the more conventional exponential decline. All this behavior is thoroughly consistent with P. J. Brown's (1976) model in which the total volume of gas in the Devonian shale (V_T) is held in three distinct ways:

1. V_1 = Free gas retained in fractures.

2. V_2 = A<u>d</u>sorbed gas on the walls of fractures.

3. V_3 = A<u>b</u>sorbed gas within the shale matrix.

V_1 gas accounts for the initial "flush" production of Devonian shale wells, but it is soon replaced by slower devolving V_2 gas. Production of V_3 gas is limited by diffusion through the virtually impermeable shale matrix and it can only be produced on reaching the nearest fracture connected to the wellbore. V_3 gas constitutes by far the greatest proportion of V_T, as suggested by the near steady-state portion of the production decline curves.

To characterize the Devonian shale and evaluate its natural gas resource potential, the EGSP has undertaken an ambitious coring program in the Appalachian, Illinois, and Michigan basins. Fifty cores have been recovered to date. A few are highly fractured; most are only moderately so; some are virtually unfractured. Though much data remain to be compiled and analyzed, the cores do provide some unambiguous, direct evidence of the dependency of gas production on natural fractures in the shale.

In 1975 the EGSP and the Consolidated Gas Supply Corporation (CGSC) (see Martin and Nuckols, 1976) cooperatively cored two wells in the Cottageville (Mt. Alto) Devonian shale gas field in Jackson and Mason Counties, West Virginia (figure 5). The wells are located on opposite sides of the field: CGSC 11940 L. A. Baler to the south and CGSC 12041 W. L. Pinnell to the north. CGSC 11940 had a natural open flow of 1,100 MCF*/day and was completed as a natural producer, that

*MCF = a thousand cubic feet of gas at standard conditions; MMCF = a million cubic feet.

is, without any form of artificial stimulation. CGSC 12041 had no discernible natural open flow and was completed as a marginal producer following a "large-scale foam fracture" treatment (Frohne, 1977), after which the absolute open flow potential was only 173 MCF/day.

Figure 6 shows the section of the gamma ray log from CGSC 11940 that includes the cored intervals. The highly radioactive, organic-rich "Zone II" shale as designated by Martin and [illegible] (1976) (now [illegible] Lower Huron [illegible]) is the primary producing interval in the [illegible] field. Fracture orientation data, derived from the oriented core and displayed in rose diagram form, are correlated to the gamma ray log in figure 6. The relationship between fracture orientation, stratigraphic interval, and gas production is a striking one. The dominant fracture orientation in the core is N45E. Between 3700 feet and 3790 feet, however, the EGSP core logging team (Byrer, Trumbo, and Rhoades, 1976) recorded both a substantially greater number of fractures and a far greater diversity of orientations than in the rest of the core. It was this interval within "Zone II" that was responsible for the 1.1 MMCF/day natural open flow from CGSC 11940.

At the time the CGSC 11940 core was processed, the practice was to log fractures indiscriminately on a per foot basis. On close examination of fractures in shale cores recovered subsequently in the program, the senior author and others (Kulander, Dean, and Barton, 1977) realized that many of the fractures were coring induced. There are several recognizable types of these coring induced fractures. One of the more common is a vertical fracture with a relatively smooth planar surface that tends to track down the center line of the core, bisecting it into two equal parts. This is the "centerline" portion of the "petal-centerline" coring induced fracture of EGSP usage (Kulander, Barton, and Dean, 1979, p. 134). This type of fracture proceeds into the core from the margin at an angle of about 45° from the vertical and curves downward ("petal" portion) to conform to the centerline, whence it continues downward by discrete extensions. [illegible] mechanics of petal-centerline fractures are complicated ([illegible] Chang, Lee, and Dean, 1979), their orientation [illegible] modern in situ stress field and thus tends to be [illegible] consistent within a given core. The authors are certain that most, if not all, of the N45E striking fractures are coring induced centerline fractures. The CGSC 11940 core is no longer intact, so this assertion cannot be proven directly. The indirect evidence, however, is overwhelming:

1. Uniform strike over an appreciable interval is characteristic of petal-centerline fractures.

2. Photographs of the core reveal unmistakable petal-centerline fractures. Figure 7 gives an edge view of one; the face of another is revealed in the left hand portion of figure 8.

3. A fracture strip log of the core shows diagrammatic representations of what can only be petal-centerline fractures throughout most of the cored interval.

The diversely oriented fractures (figures 9 and 10) in the producing interval, 3700 to 3790 feet, however, are certainly of geologic origin. Only within that interval did Byrer, et al. (1976) record mineralized (dolomite) fractures, an observation subsequently confirmed and expanded by Patchen and Larese (1976, p. 7) and by Larese and Heald (1977, pp. 19-22) (see figures 11 and 12).

In contrast to the CGSC 11940 core, the CGSC 12041 core was virtually devoid of fractures. Those few that were observed all strike N65E and are almost certainly coring induced centerline fractures. Thus, the two EGSP core wells in the Cottageville Field, less than 5 miles apart, serve as dramatic contrasting examples of the dependency of Devonian shale gas production on natural fractures, and especially intersecting, interconnected natural fracture systems.

Origin of Natural Fractures

What is the true nature of these all important natural fractures? Are they a highly localized phenomenon, in which case Devonian shale production will be forever confined to the few areas where fractures occur? Or, are they ubiquitous, variations in fracture density accounting for the distinction between traditional producing and nonproducing areas?

Outcropping dark, organic-rich Devonian shale is conspicuously jointed, typically displaying one or two systematic sets and a corresponding number of associated nonsystematic sets. Systematic joints of a given set are characteristically highly regular, i.e., evenly spaced, planar, and smooth. Visual comparison suggests that black shale units are more highly jointed, certainly more regularly and obviously jointed, than superjacent and subjacent gray shale units. The great majority of joints contained in a given black shale unit terminate at the upper and lower contacts with gray shale. (The senior author observed the foregoing on a field trip through central and western New York; Patchen and Dugolinsky, 1979.) Do these joints exist at depth? Are they the source of gas productive fracture permeability in the Devonian shale of the subsurface?

A common misconception, espoused by several respected textbooks, holds jointing to be a near-surface phenomenon, primarily the result of erosional unloading of buried rock masses. The reasoning generally goes as follows:

1. Joints are tension fractures, as indicated by several lines of evidence.

    a. Imperceptible offset of pre-existing geologic features.

    b. Tendential features (viewed edge-on) diagnostic of tension fractures (Kulander, et al., 1979).

    c. Transient features (viewed face-on) diagnostic of tension fractures (ibid).

2. True tensional stresses cannot persist below very shallow depths in the earth's crust, depths on the order of a few hundred feet, because of the effect of the lithostatic gradient.

3. Therefore, jointing is a near-surface phenomenon.

The fallacy in this line of reasoning lies in the assumption that only true tensional stresses can cause rocks to fail in tension.

Figure 13 depicts the composite failure envelope for brittle materials, including rocks, together with the Mohr's Circle representation of stress. If compressive stress is defined as positive with values increasing to the right, Mohr's circles representing possible stress states in the earth's crust (compressive stresses only) are confined to the right of the ordinate. The diagram shows that those circles large enough to contact the composite failure envelope do so only in the linear portion. The resulting ruptures are shear failures (i.e., faults); tension failures are impossible.

Rocks, however, do not fail in response to absolute stress; they fail in response to effective stress (Jaeger, 1962, p. 166; Hubbert and Rubey, 1959), which is related to absolute stress in the following manner:

$$\bar{\sigma} = \sigma - p \qquad (1)$$

where:

$\bar{\sigma}$ = effective stress

σ = absolute stress

p = the pore pressure exerted by interstitial fluids.

In any geologic environment where the fluid pore pressure is greater than the absolute stress, this relationship states that the effective stress will have a negative sign and, thus, be tensile. The relevance of that conclusion to the formation of joints can be seen in figure 14, where the normal stress axis is relabled to read effective stress ($\bar{\sigma}$) rather than absolute stress (σ). In this reference system, for a given absolute stress state remaining constant, increasing pore pressure has the effect of displacing the Mohr's circle to the left, eventually driving it against the failure envelope. If the circle, the diameter of which is equivalent to the maximum stress difference ($\bar{\sigma}_3 - \bar{\sigma}_1 = \sigma_3 - \sigma_1$), is sufficently small, it will contact the envelope where it crosses the abscissa, to the left of the ordinate, and tensile failure will result. Inasmuch as the point of tangency occurs on the abscissa, the angle 2Θ between the compressional axis and the radius to that point will equal 180°, implying that the angle between the fracture plane and the least principal stress will be 90°. In simpler terms, figure 14 predicts that tensile fractures or joints can occur in rocks under conditions of elevated interstitial fluid pore pressure, provided the ambient stress anisotropy is relatively small. It further predicts that they are created in an orientation perpendicular to the direction of the minimum compressive stress. Thus, the mechanics of geologic jointing can be viewed as exactly analogous to that of artificial hydraulic fracturing (see Hubbert and Willis, 1957 for discussion on hydraulic fracturing mechanics). The most important consequence of this conclusion is the perception that jointing need not be a depth limited phenomenon.

This insight on the fundamental mechanics of jointing is not original with the authors. Donald T. Secor (1965) originally proposed it; though, it is not yet universally accepted. His exposition of what could be termed "the hydraulic fracturing theory of jointing" is more highly developed than the foregoing. In figure 15, an adapted version of Secor's (1965) figure 3, the normal stress axis (abscissa) on both sides of the shear stress axis (ordinate) has been graduated in multiples of "-K," the tensile strength of any rock under consideration. The composite failure envelope crosses the normal stress axis at -K. Hence, from figure 14, the condition for jointing is:

$$\bar{\sigma}_3 = -K \tag{2}$$

where:

$\bar{\sigma}_3$ = the least <u>effective</u> principal stress

and, as before,

$-K$ = the tensile strength of the rock.

Figure 15 shows that when displaced to the left by elevated fluid pore pressure, all Mohr's circles smaller than a certain critical diameter are capable of initially contacting the composite failure envelope at -K, where it crosses the abscissa. Larger circles initially contact the failure envelope to the right of the ordinate, with the result that faulting, rather than jointing, occurs. The critical circle is centered at +K and crosses the abscissa at +3K, as well as at -K. Inasmuch as that circle has a diameter of 4K, the criterion for jointing may be stated as follows:

jointing occurs when

$$\bar{\sigma}_3 = \sigma_3 - p \leq - K \tag{3}$$

or equivalently

$$p - \sigma_3 \geq K \tag{4}$$

provided that

$$\bar{\sigma}_1 - \bar{\sigma}_3 = \sigma_1 - \sigma_3 \leq 4K. \tag{5}$$

Or, alternatively stated, jointing occurs whenever the interstitial fluid pore pressure exceeds the minimum principal compressive stress (absolute) by the amount of the tensile strength, provided the maximum stress difference does not exceed four times the tensile strength.

What evidence is there to support the contention that the natural fractures responsible for most gas production from the Devonian shale of the Appalachian foreland are joints created in the manner described above? Natural fractures observed in Devonian shale core fall into one of three categories: slickensided, mineralized, and unfilled. Slickensided fractures are clearly not joints, but faults, having experienced lateral displacement at some point in time. High-angle slickensided fractures are rare. Low-angle slickensided fractures are rare to nonexistent throughout much of the Appalachian Plateau, but they become common in the folded plateau and increase dramatically toward the Allegheny Front. They qualitatively reflect the degree of detachment activity in the Devonian shale. The role of slickensided fractures in Devonian shale production is as yet uncertain and the subject of some debate. Although some of the slickensided fractures are also mineralized, most of the mineralized natural fractures observed in Devonian shale core show no evidence of lateral displacement, i.e., no trace of slickensiding and no offset of bedding or preexisting fractures. Faint radial and crescentic markings, characteristic of joints, however, are often discernible on the planar faces of both the unfilled <u>and</u> the mineralized fractures. These are the transient fractographic features described and discussed at length by Kulander, Barton, and Dean (1979). These fracture face markings are diagnostic of extensile fracturing, i.e., jointing.

That most of the joints in Devonian shale core are mineralized (primarily calcite and/or dolomite), at least to some degree, is mute testimony to the presence of aqueous fluids at some point in their geologic history. The joints cannot be true tension fractures resulting from erosional unloading, because most of the EGSP Devonian shale cores were extracted from depths of several thousand feet, depths that are an order of magnitude greater than those at which true tensile stresses can exist in the earth's crust. Moreover, since deposition, each Devonian shale unit has been subject to nearly continuous and often rapid burial until the onset of the modern cycle of erosion initiated by the Alleghenian Orogeny. Also, the introduction of mineralizing fluids into these joints is hardly unrelated to their creation, since:

1. The walls of mineralized fractures in the Devonian shale are commonly separated by the mineral filling to a noticeable degree, 1 to 3 mm or more, implying that the mineralizing fluid was under pressure, forcing the fracture open while mineral matter was precipitating on the walls.

2. In certain instances the mineralization has a noticeably linear fabric, a semi-fibrous appearance, that is oriented perpendicular to the plane of the fracture, implying that distension of the fracture and mineralization occurred concurrently.

Grounds exist for inferring that the fractures were created and mineralized after the lithification of the Devonian shale, but prior to the establishment of the modern geologic environment. They cannot be penecontemporaneous with deposition, because they are true brittle fractures, as indicated by their generally planar habit and the diagnostic face markings. To behave as a brittle substance, the shale had to be at least well consolidated, if not indurated. On the other hand, no detectable mineralizing fluids have yet been encountered during coring operations, which accords with the reputation the Devonian shale has among drillers and producers of being a water-free formation. Moreover, most mineralized fractures are now so completely so, as to be virtually impermeable to aqueous fluids (though presumably not to gas). Thus, most of the jointing, or extension fracturing, in the Devonian shale probably occurred during the waning stages of dewatering, but not until induration was well advanced.

Conclusion and Synthesis

The Devonian shale of the eastern interior basins is a potentially major resource of natural gas, largely unexploited because of its exceedingly low permeability and consequently low average per well production rates. The weight of evidence, acquired under or made available through the Department of Energy's (DOE) Eastern Gas Shales Project impels the authors to conclude that natural fracture systems are indispensable to Devonian shale production, even with modern well stimulation technology. The natural fractures to which production can be attributed appear for the most part to be joints rather than faults, i.e., extension fractures rather than lateral displacement fractures. With the recognition that rocks fail under effective stress rather than absolute stress comes the realization that there is theoretically no limit to the depth at which jointing can occur, provided the internal fluid pore pressure exceeds the minimum principal stress (compressive) by the amount of the tensile strength of the rock and the maximum principal stress difference is not greater than four times that amount. Carbonate mineralization typical of extension fractures observed in Devonian shale core bears mute testimony to the role of pressurized fluids in their creation. The authors, therefore, conclude that the natural fractures essential to production from the Devonian shale are dominantly joints that originated as natural hydraulic fractures, induced by excessive fluid pore pressure that built up at various times during its post-depositional history.

These natural hydraulic fractures, like their artificial counterparts, must have aligned themselves parallel to the plane of the two then prevailing maximum principal stresses, i.e., perpendicular to the minimum principal stress. Thus, joints in the Devonian shale represent a cumulative, though fragmentary, record of its stress history. This hypothesis suggests an exploration strategy for fractured reservoirs in the shales. Were it exposed at the surface, it should be possible to unravel some of the tectonic history of the Devonian shale by establishing a relative chronology among joint sets (see Kulander, et al., 1979). For the shale in the subsurface, perhaps the process can be profitably reversed. Using the tectonic histories of marginal areas and the underlying basement as boundary conditions, the explorationist should try to synthesize a tectonic history for the Devonian shale and use it to predict potentially resulting joint patterns, from which he could identify likely areas of concentrated fracturing.

Of particular concern to the Devonian shale explorationist in the Appalachian Basin are possible interactions between the zones of influence of cover-restricted detachment (thin-skinned) tectonics and basement tectonics. Overbey (1976) was intrigued by this possibility following his discovery that the near-surface, maximum horizontal in situ principal stress, which seems to have a regional east-west orientation throughout much of the Appalachian Basin, was reoriented over the Rome Trough, a buried rift system, to conform to its strike.

The authors formulated two supposedly competing hypotheses to explain this phenomenon. The basis for each was some postulated interaction between thin-skinned and basement tectonics. Both hypotheses presume the existence of buried normal faults that markedly offset the basement unconformity in relationship to the total thickness of the sedimentary cover (see Harris, 1975 and 1978, also Kulander and Dean, 1978). They differ in the proposed manner by which the buried faults interact with the detachment tectonics characteristic of the Appalachians. The "buried fault buttress model" (figure 16) postulates a passive basement with a pre-existing normal fault and an actively sliding cover. The "buried fault slip model" (figure 17) postulates a passive cover under the influence of detachment related lateral stress and a rejuvenated normal basement fault slipping a small fraction of the amount of the total pre-existing displacement.

To evaluate the plausibility of the two hypotheses the EGSP let a small contract to West Virginia University (WVU) for Professors S. H. Advani and H. V. GangaRao of the Engineering and Applied Science Department and their student to conduct finite element stress analysis on the two idealized models (figures 16 and 17). Involving a high-speed computer, finite element stress analysis is a means of solving for the complete state of stress (intensity and orientation) at any point within a continuous medium, given boundary conditions and physical properties. The results of this investigation, which in the larger sense was also a feasibility study on the application of finite element stress analysis to tectonic problems, were summarized in a paper presented at the First Eastern Gas Shales Symposium (Advani, GangaRao, Chang, Dean, and Overbey, 1977). From a strictly theoretical viewpoint, both of the models turned out to be equally plausible explanations for the in situ stress reorientation observed at the surface. The output of the NASTRAN computer program, which performed the analysis, enabled S. H. Advani and company to contour stress intensity in the cross-sectional view of the two models, figures 16 and 17. The horizontal stress intensity contour plots for the two models both displayed a near-surface zone of relative tension over the buried basement fault. Had the models been formulated in three dimensions, this condition would have been manifested as a reversal of the relative magnitudes of the two horizontal principal stresses, which is equivalent to the in situ stress reorientation observed in nature.

Though the two models predict indistinguishably similar surface stress configurations, the predicted subsurface configurations differ very significantly. Stress intensity plots for the buried fault slip model (figure 17) reveal subsurface zones of low stress and even relative tension. Were conditions corresponding to those of the buried fault slip model to have occurred in nature, the equivalent zones would have been ideal sites for concentrated jointing, i.e., natural extensional fracturing by the mechanism described in the preceding section.

The question yet remains, which of the two proposed hypotheses idealized in the cross-sectional models (figures 16 and 17) best explains the observed phenomenon of reoriented stress over the Rome Trough? This and similar questions are not academic, as correct answers may point the way to subsurface fractured reservoirs in the Devonian shale. Sophisticated exploration techniques, to wit, finite element stress analysis, can theoretically identify environments particularly prone to natural fracturing within a specified tectonic context. The problem lies in specifying the tectonic context, which corresponds to the boundary conditions of the model to be analyzed. The Devonian shale explorationist is limited by his ignorance of tectonic influences upon the shale. Clarifying some of these uncertainties is the raison d'être of this volume, "Western Limits of Detachment and Related Structures in the Appalachian Foreland."

Known Gas Shale Deposits Located in the United States

Eastern Gas Shale Deposits

Figure 1. Distribution of Devonian shale in the eastern United States.

AVERAGE PRODUCTION DECLINE CURVES
282 SHALE WELLS, 235 CLINTON WELLS

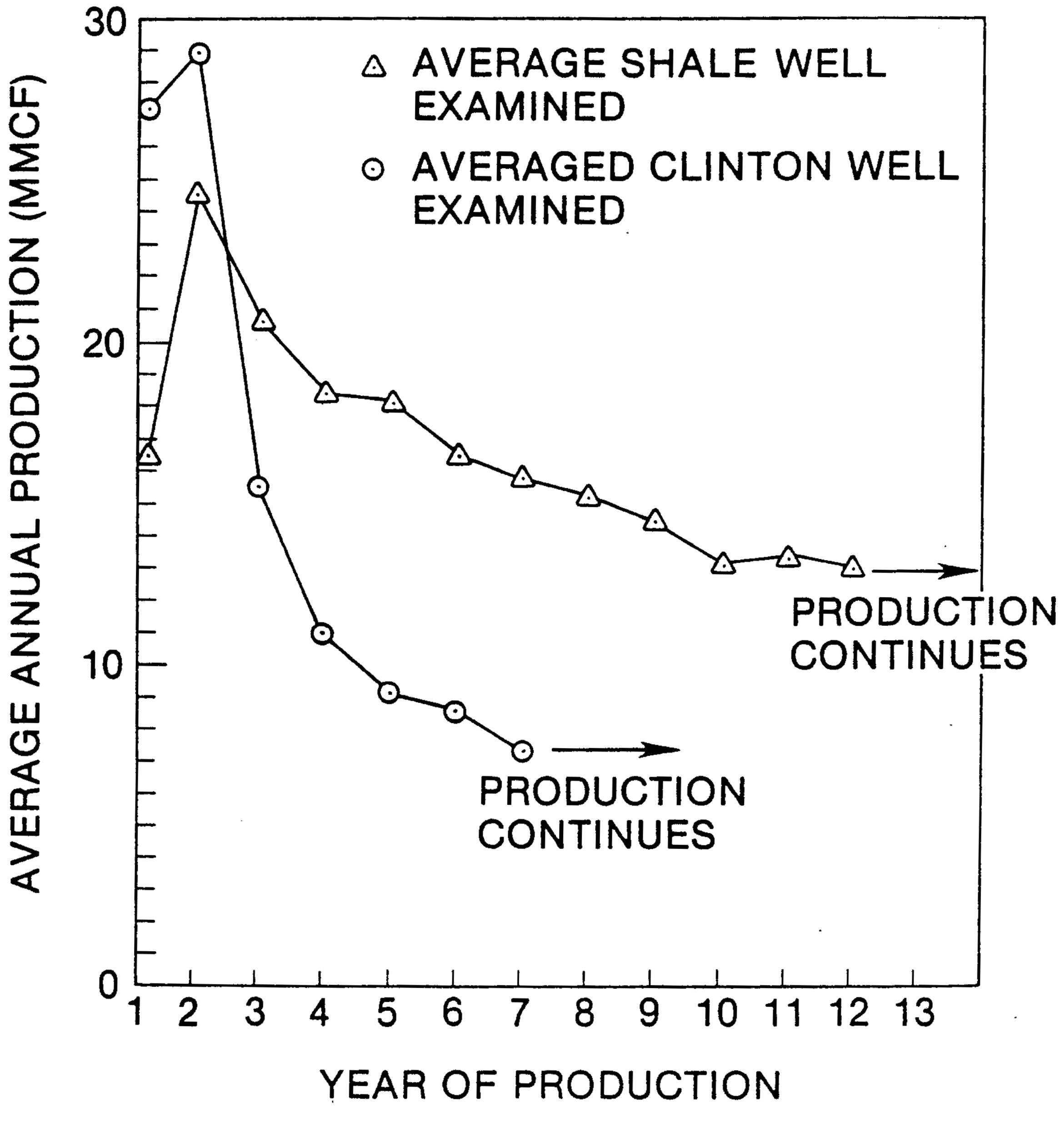
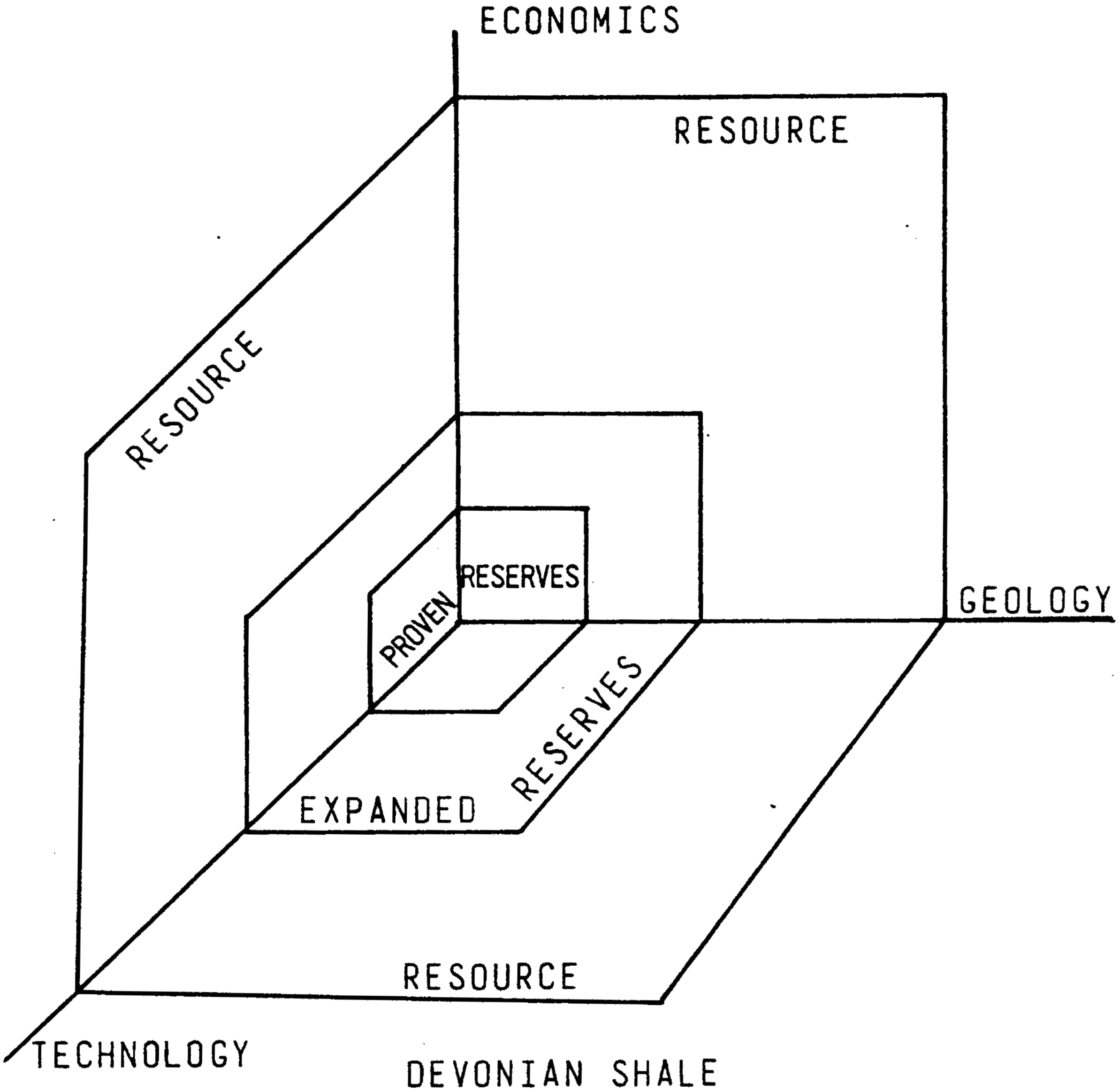


Figure 2. Average production decline curves for unconventional shale wells compared with conventional sandstone wells (Brooks, Forrest, and Morse, 1974, figure 5).



DEVONIAN SHALE
GAS
RESOURCE & RESERVES

Figure 3. Dependency of Devonian shale gas reserves upon economics, technology, and geology.

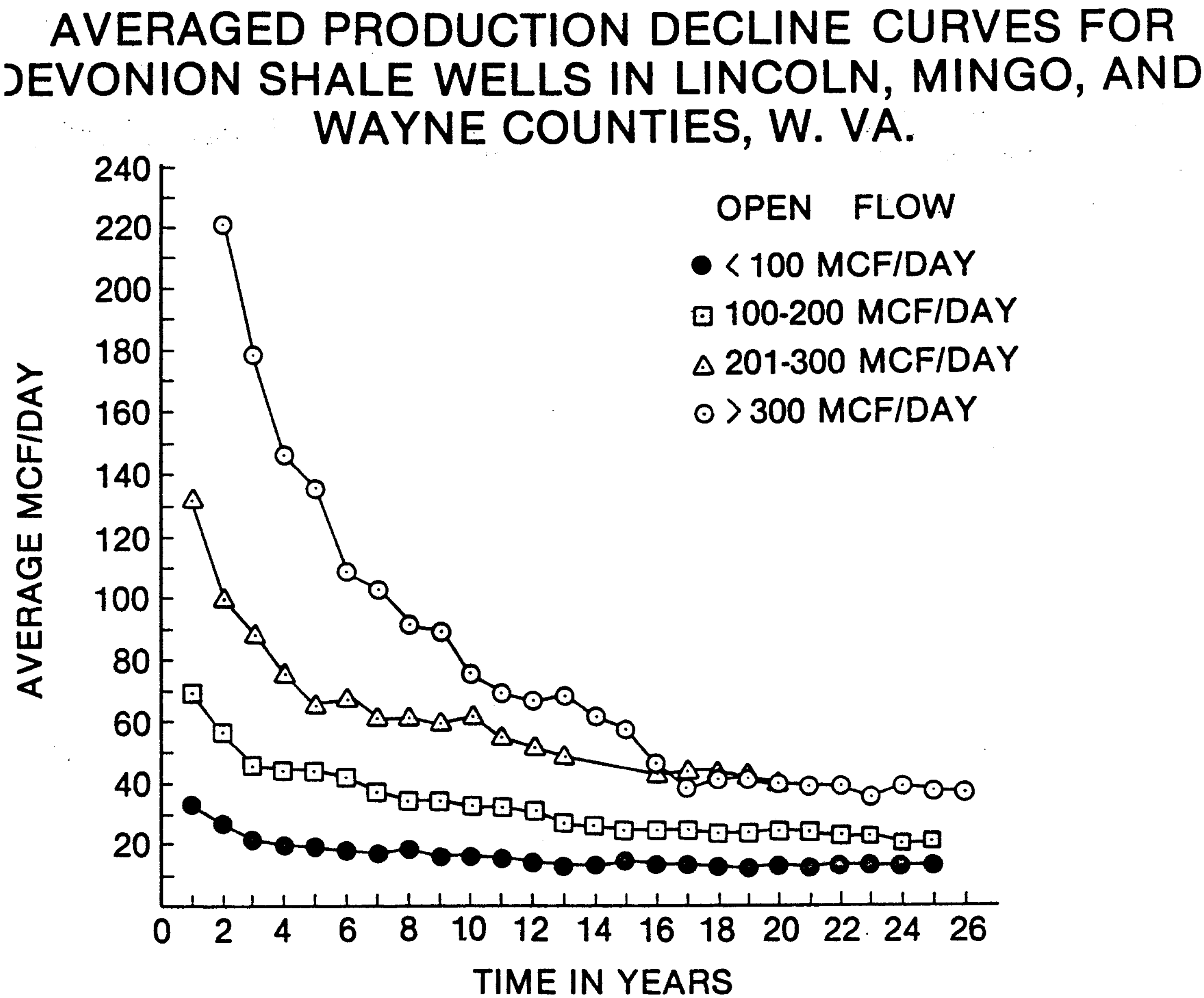


Figure 4. Averaged production decline curves for Devonian shale wells differentiated according to open flow (Bagnall and Ryan, 1976, figure 11).

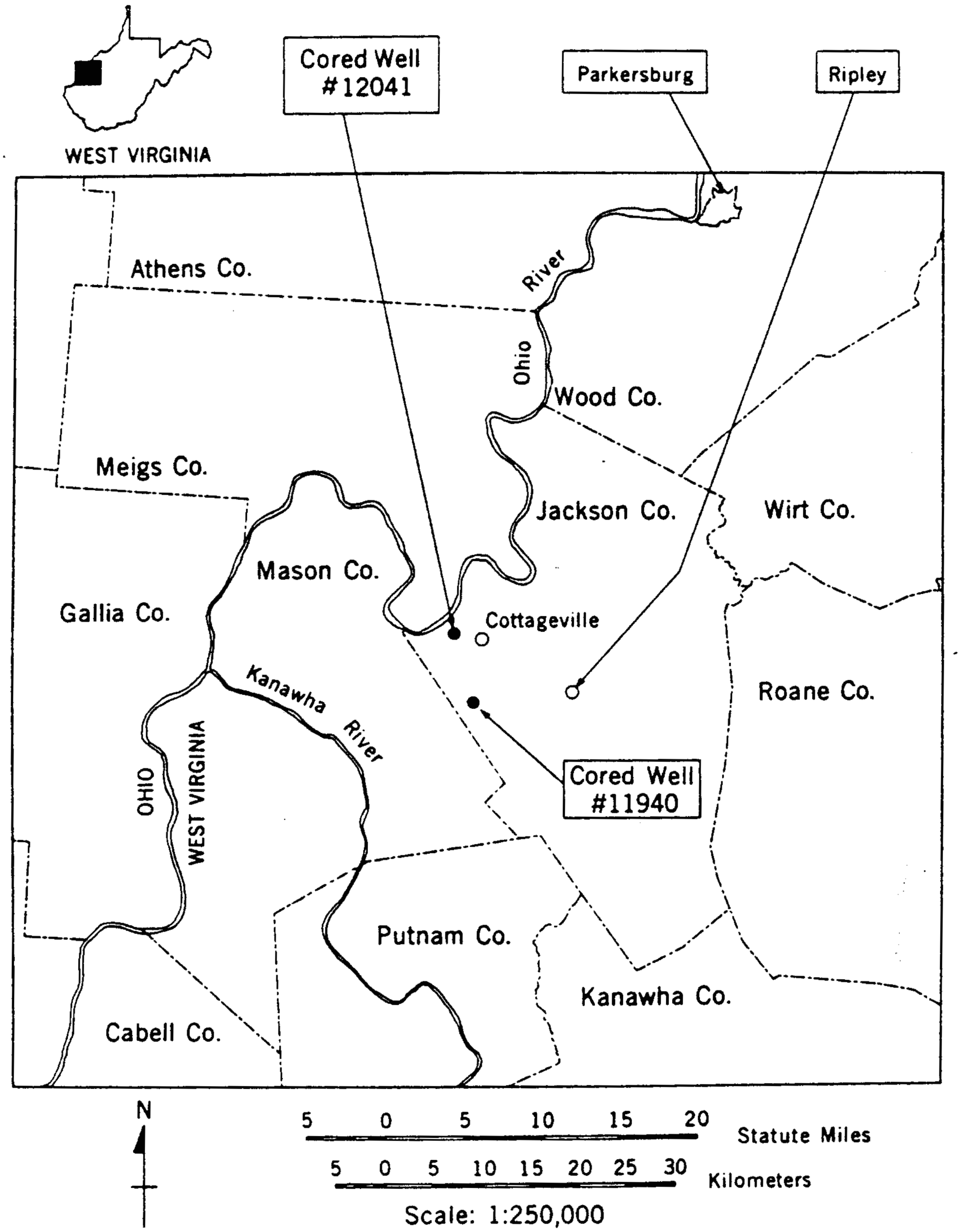


Figure 5. Location of cored Devonian shale wells in the Cottageville gas field of Jackson and Mason Counties, West Virginia (Byrer, Trumbo, and Rhoades, 1976, figure 1).

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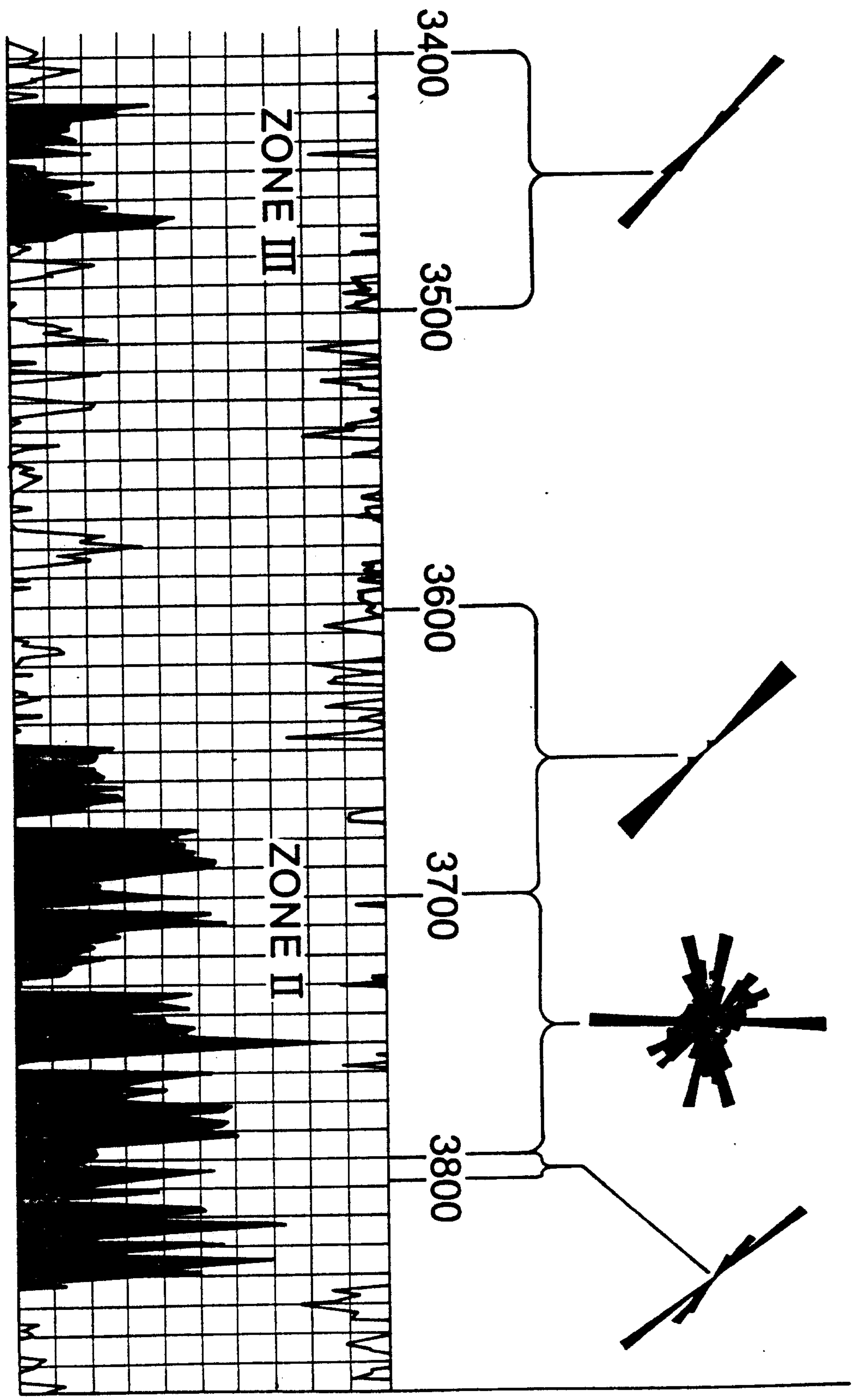
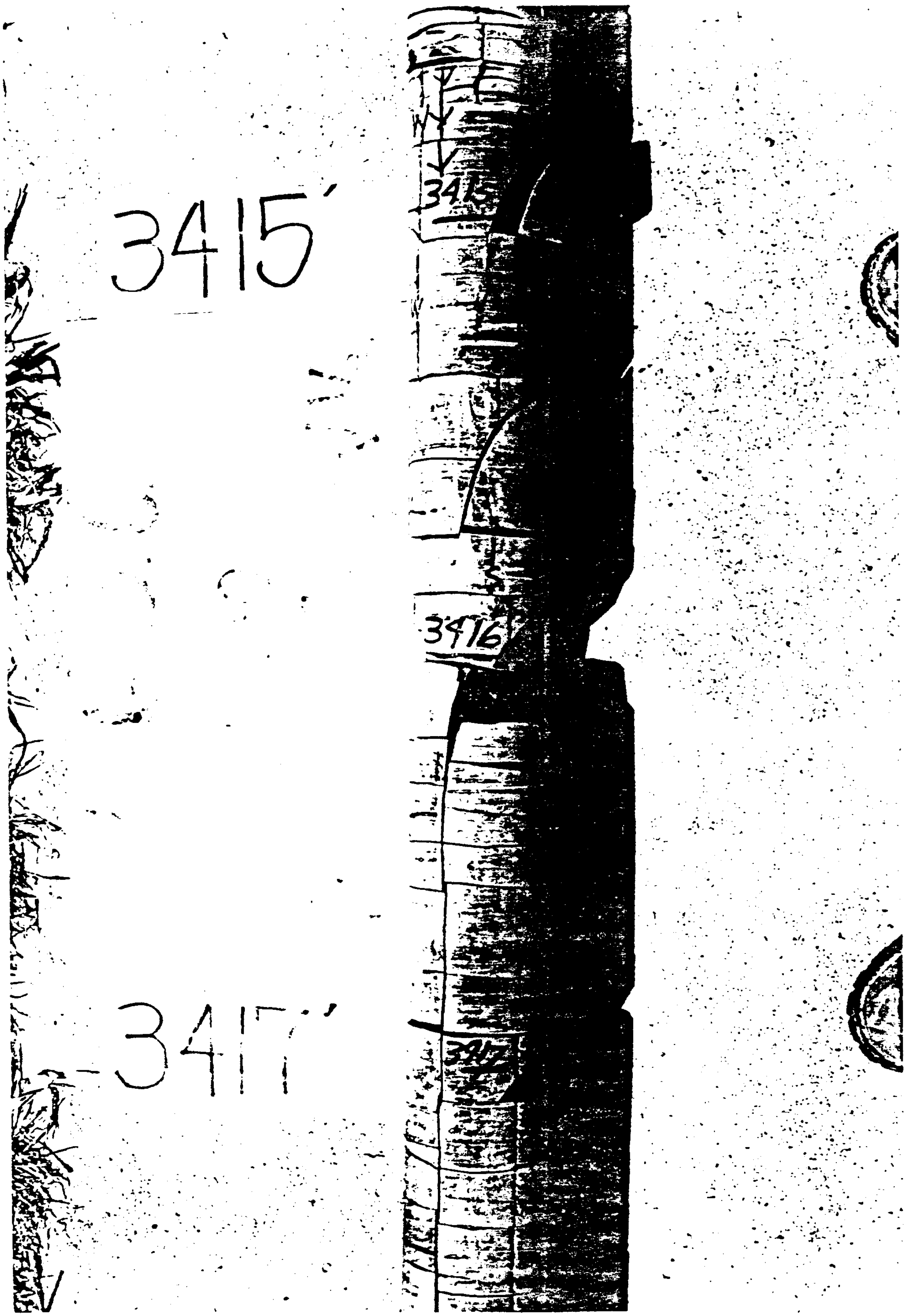


Figure 6. Gamma ray log and core fracture orientations from CGSC 11940, Jackson County, West Virginia (after Martin and Nuckols, 1976, figure 13).



gure 7. Edge-on view of a petal centerline and two petal fractures in the oriented core
tracted from CGSC 11940, Jackson County, West Virginia.

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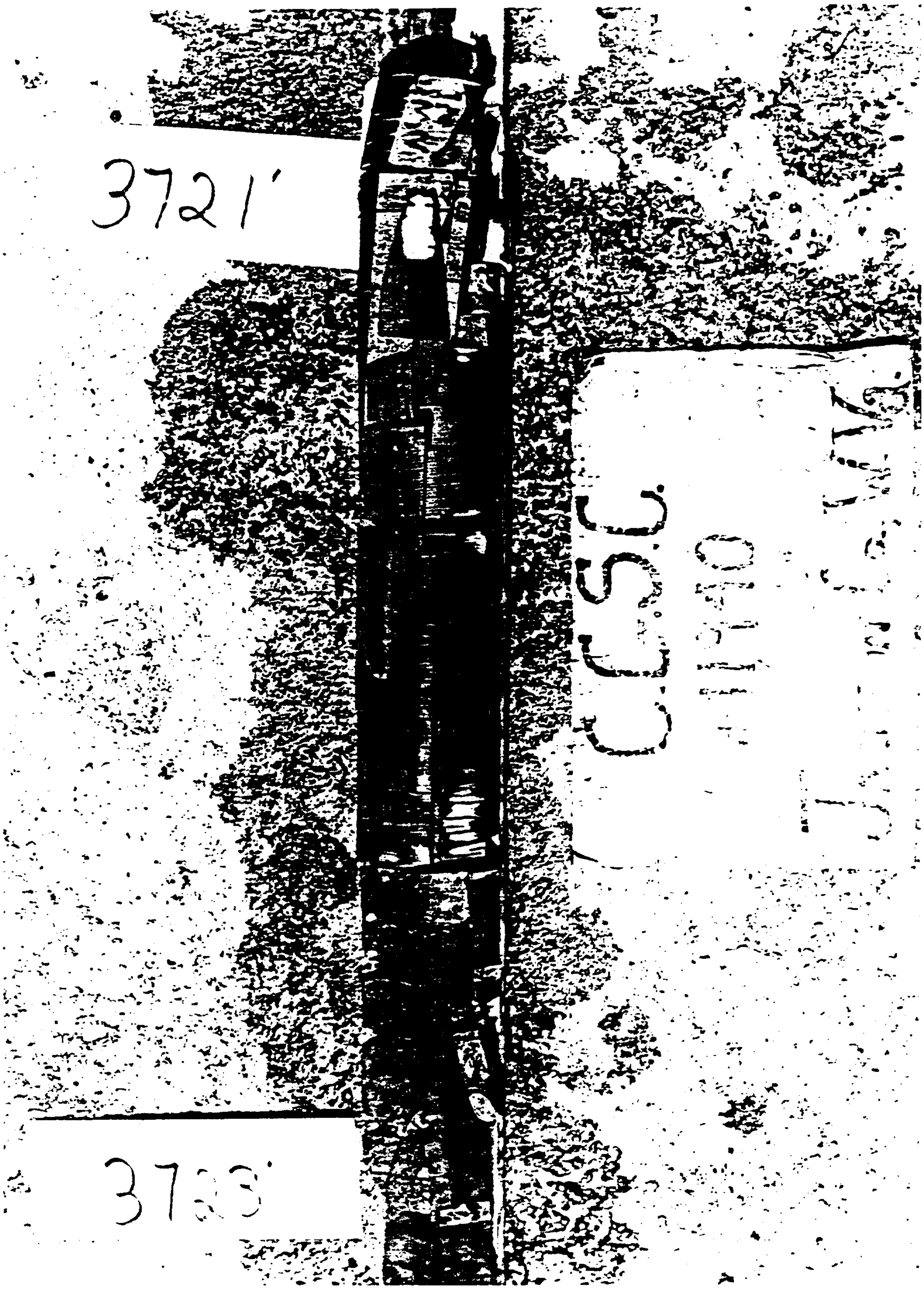
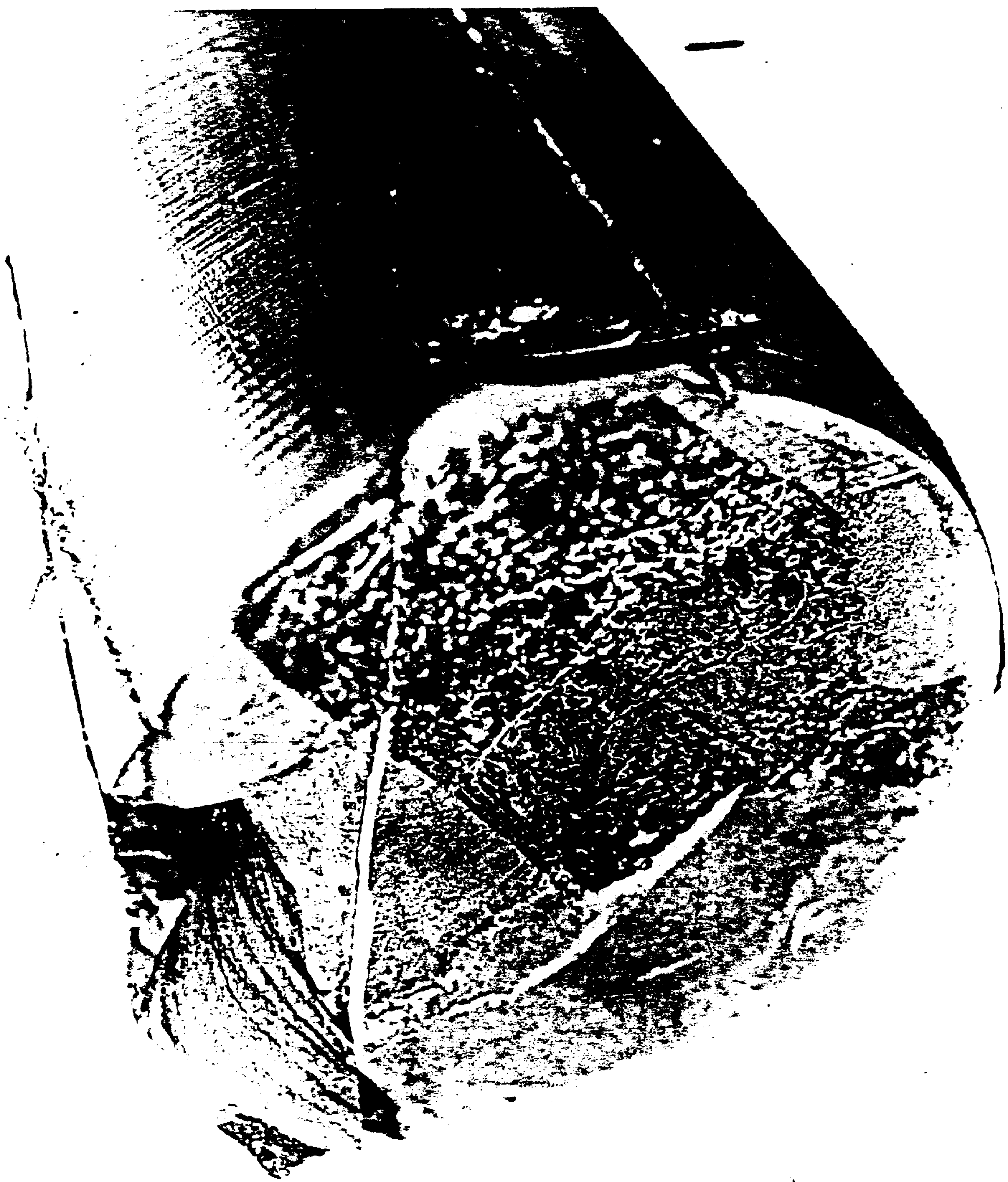
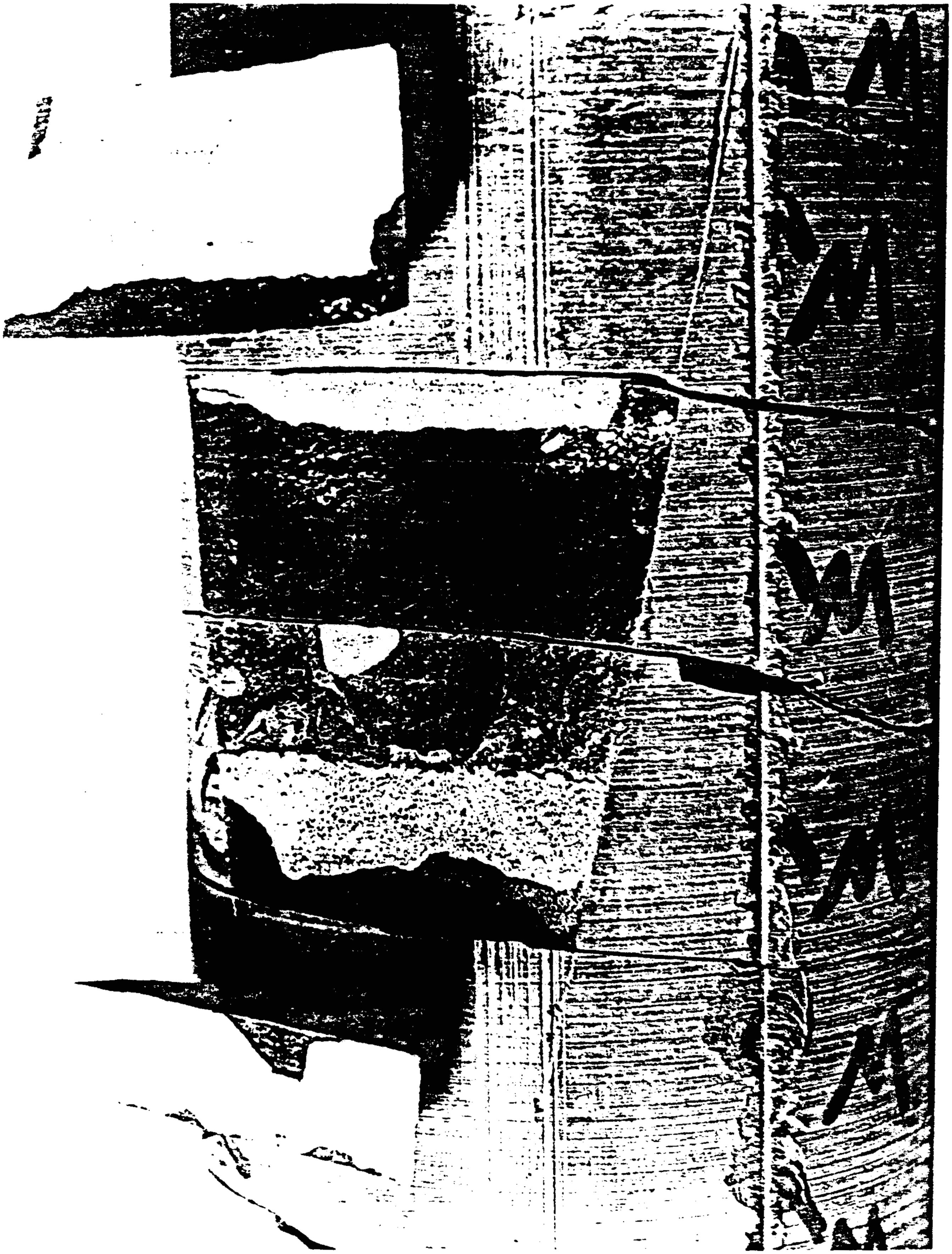
igure 8. Fractures, coring induced and natural, in the CGSC 11940 core. The left hand ortion (bottom of page) reveals a face-on view of a centerline fracture. Note the closely paced intermediate arrest lines, indicating that the fracture propagated down-core by iscrete extensions.



gure 9. Diversely oriented, intersecting natural fractures in the CGSC 11940 core.



gure 10. Close-up of intersecting natural fractures in the CGSC 11940 core.



'igure 11. Heavy dolomite mineralization on the face of a natural fracture in the CGSC 1940 core.

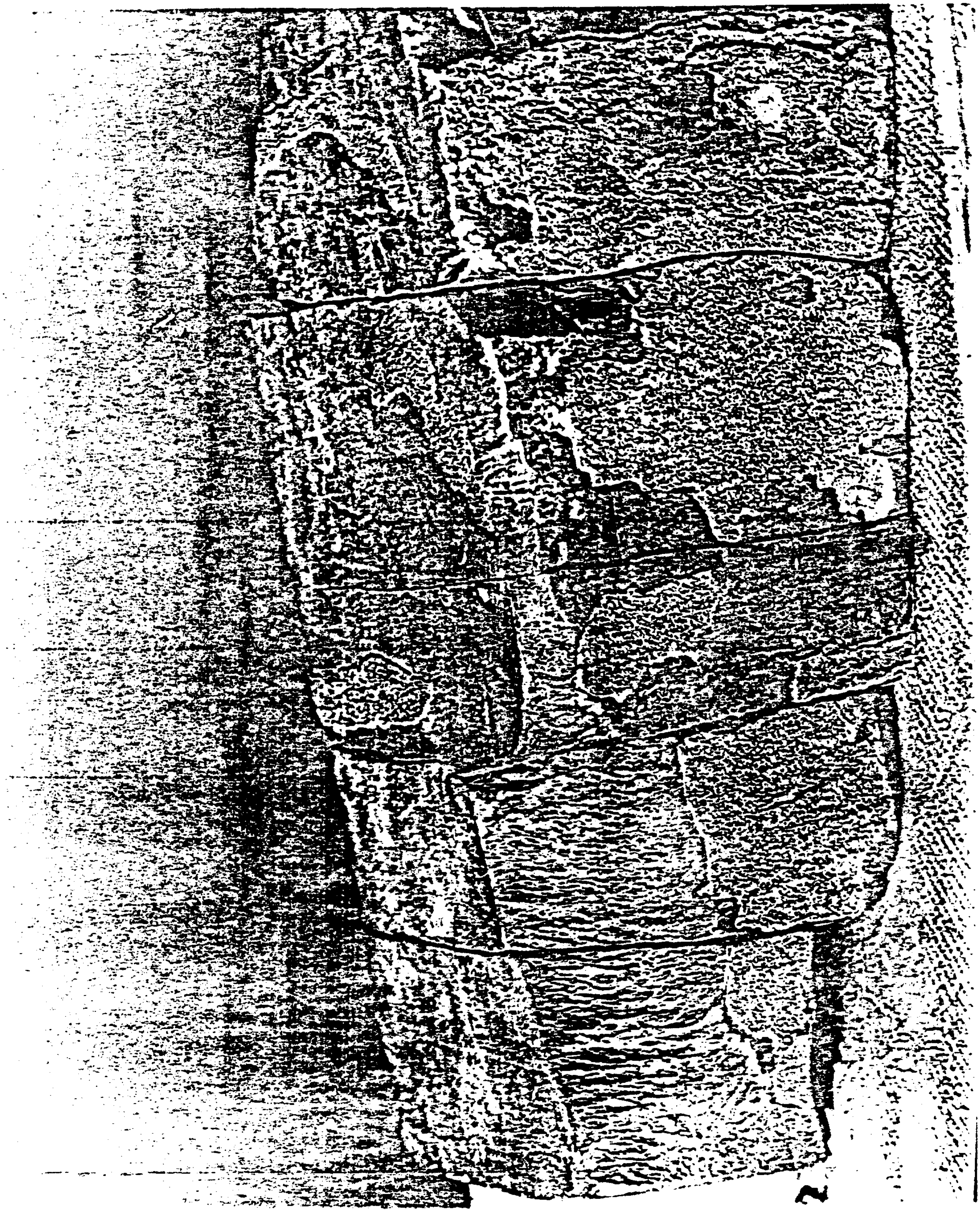
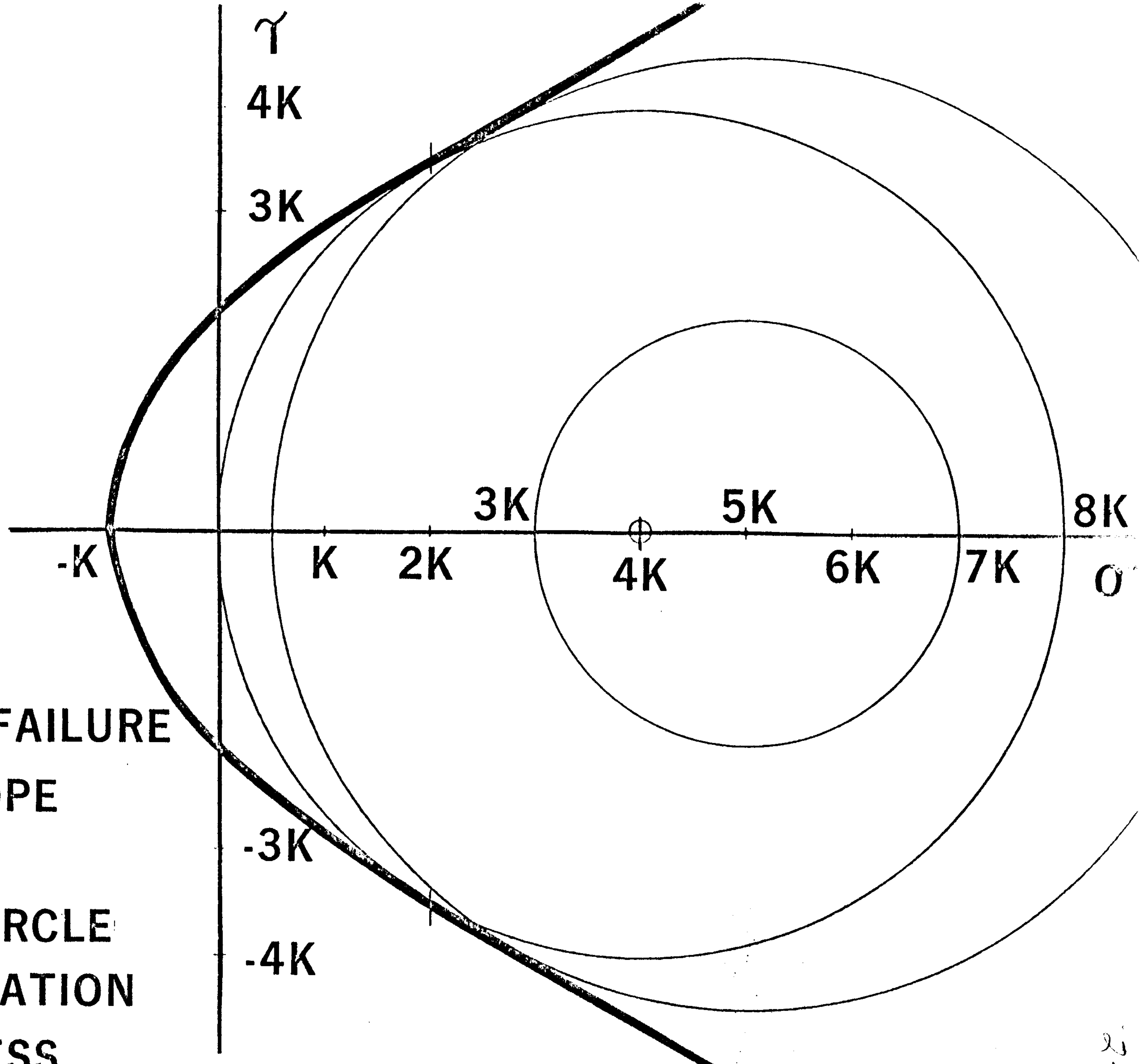


Figure 12. Dolomite mineralization on the faces of two intersecting fractures in the CGSC 11940 core.



COMPOSITE FAILURE ENVELOPE and MOHR'S CIRCLE REPRESENTATION OF STRESS

Figure 13.

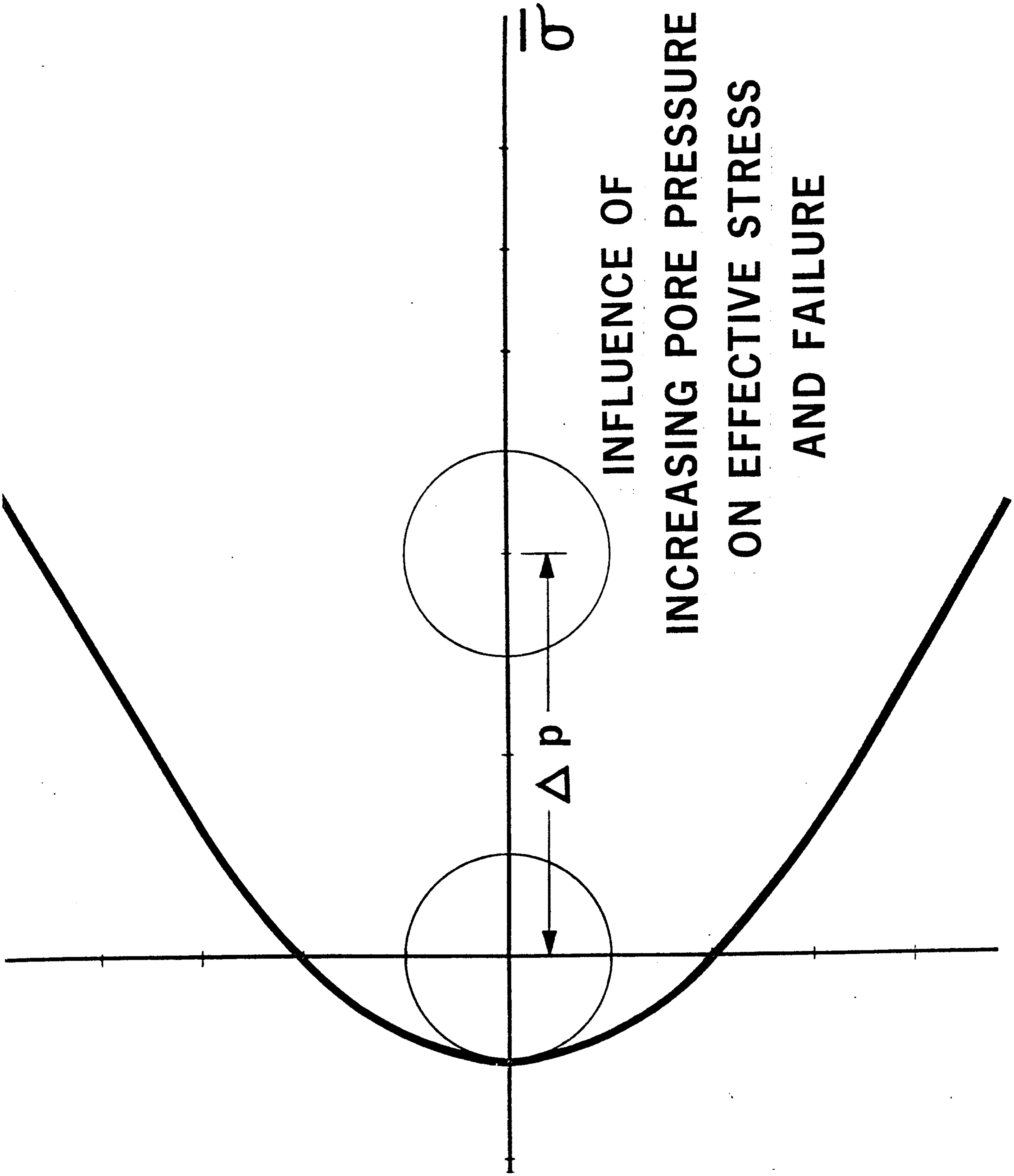


Figure 14. The influence of fluid pore pressure on the Mohr's Circle representation of effective stress. Note that increasing pore pressure displaces the circle progressively to the left, eventually driving it against the failure envelope.

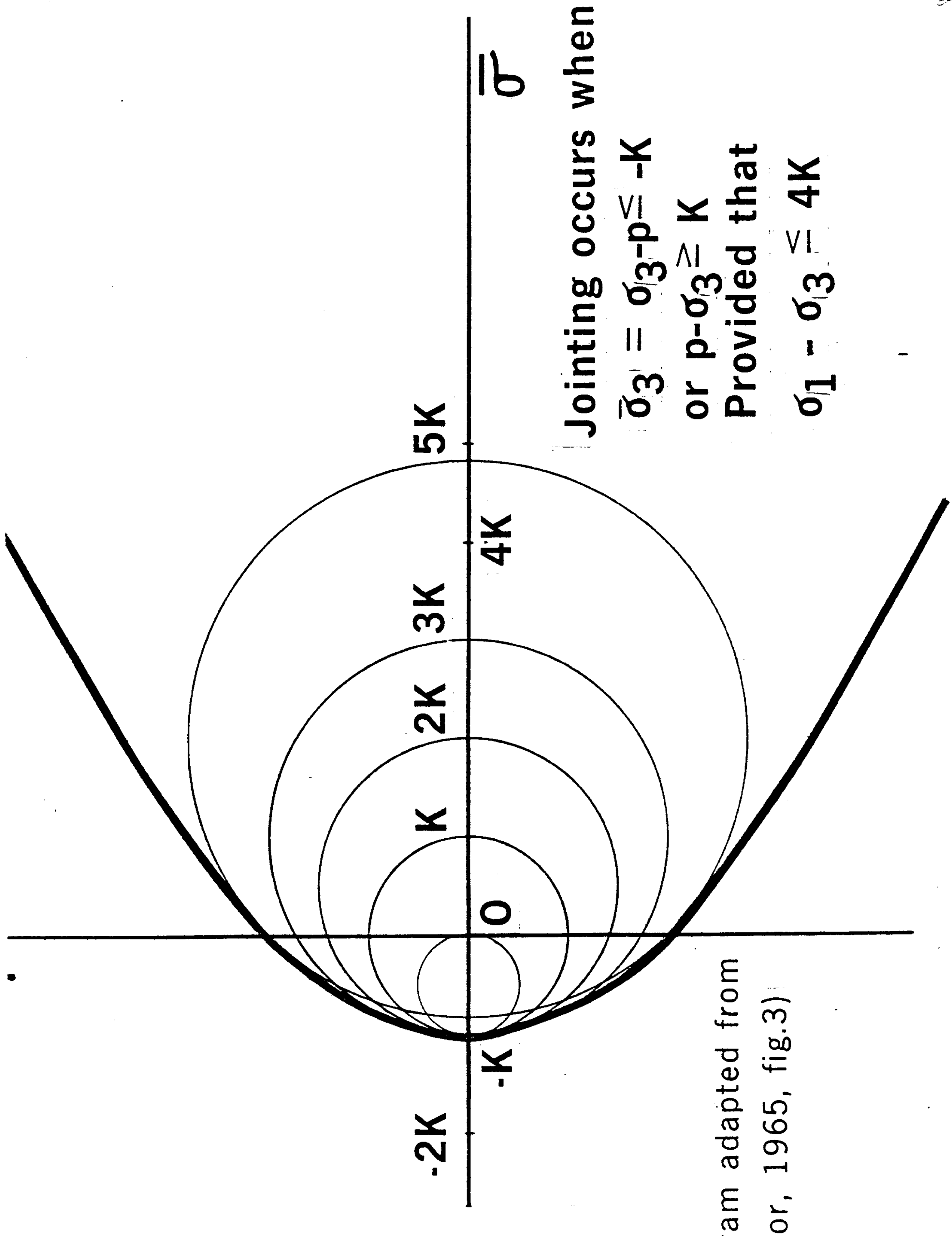
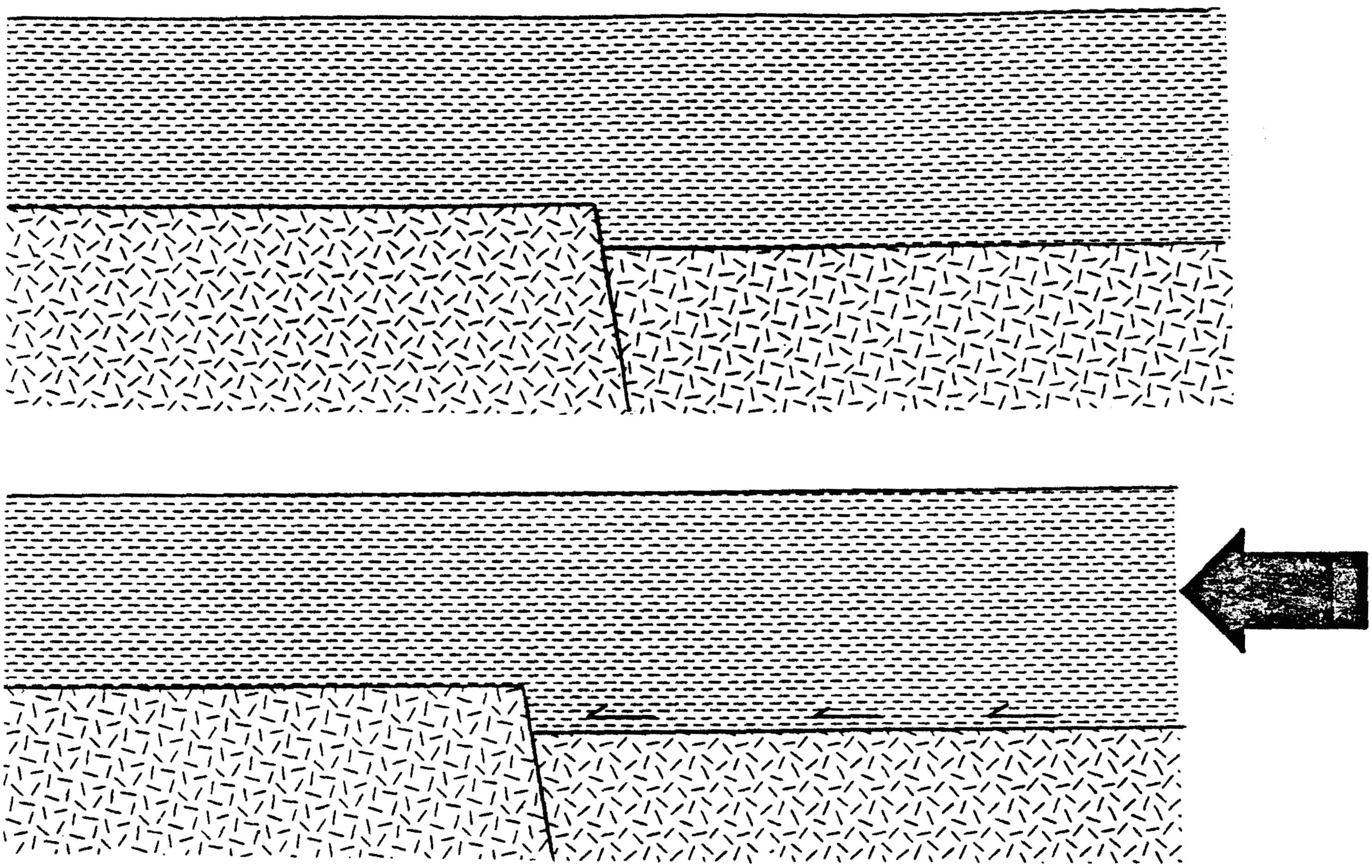
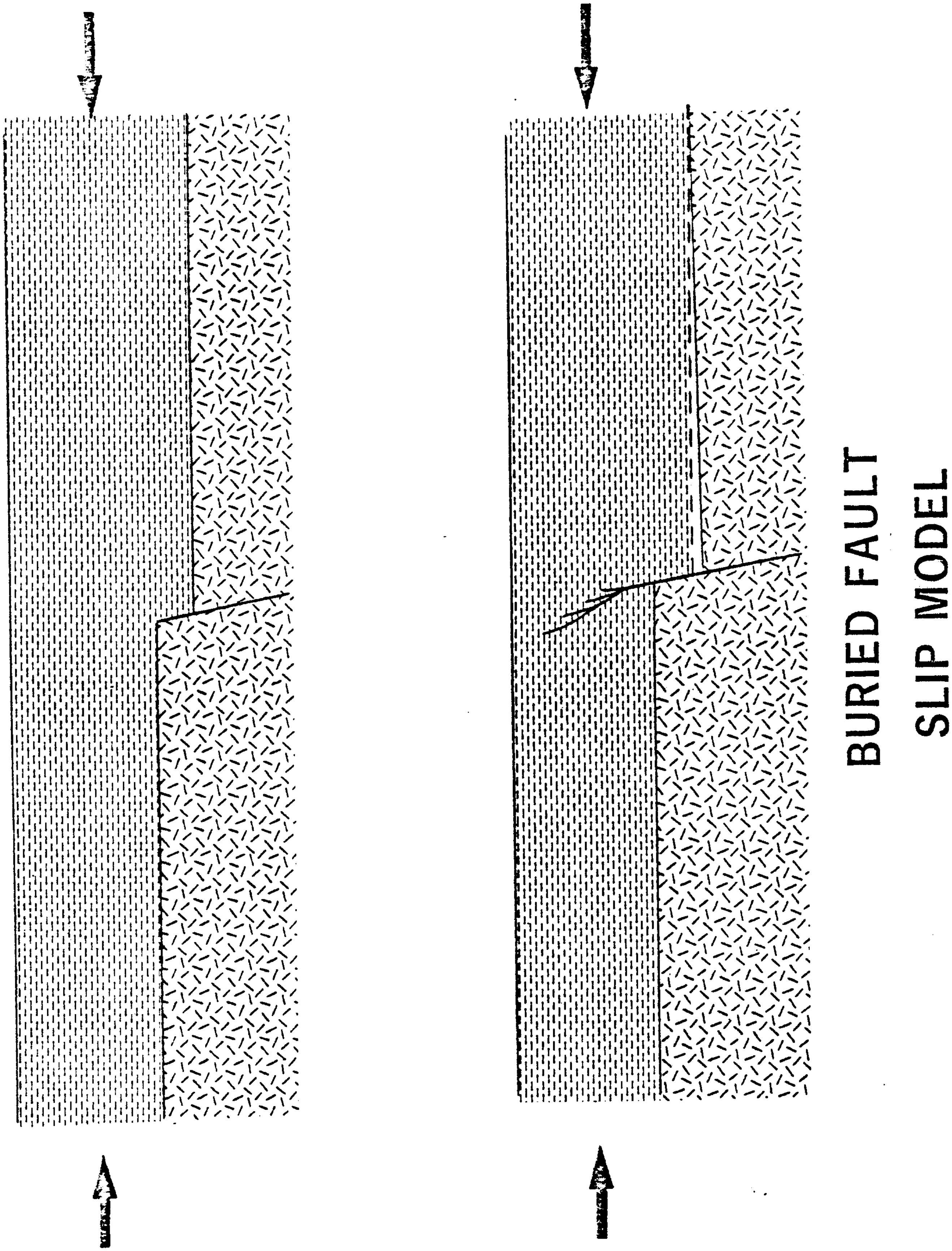


Figure 15. The condition for jointing.



BURIED FAULT BUTTRESS MODEL

igure 16. The "buried fault buttress model", the first of two proposed to explain the apparent eorientation of the near surface in situ stress over the Rome Trough. The model postulates passive basement with a pre-existing normal fault and an active cover capable of sliding at or ear the basement unconformity.



igure 17. The "buried fault slip model", the second of two proposed to explain the apparent eorientation of the near-surface in situ stress over the Rome Trough. The model postulates passive cover under the influence of detachment related lateral stress and a rejuvenated ormal basement fault slipping a small fraction of the amount of the total pre-existing isplacement.