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GRASS CREEK PHOSPHORIA-TENSLEEP ALTERNATE GAS-WATER INJECTION FEASIBILITY STUDY

By

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ABSTRACT

A reservoir engineering study was made to ascertain the potential recoverable oil from the Grass Creek Phosphoria-Tensleep reservoirs. The volumetric method was used to calculate that 218.6 million STB of oil was originally in place. Primary-performance calculations were made and compared to actual performance to establish that 56.9 million STB of oil would be recovered by natural water drive. Secondary-recovery predictions were made to determine the additional oil recoverable by alternate gas-water injections.

Secondary-recovery calculations indicate that 13.8 million STB of additional oil can be recovered from the reservoirs, increasing ultimate recovery from 26 to 32 percent of the original oil-in-place. Profit, discounted at 10 percent, from secondary-recovery operations would be $9,381,000 making the project economically attractive.

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INTRODUCTION

The Grass Creek Phosphoria-Tensleep reservoir has been produced competitively without unitization since 1922. Oil production from these two reservoirs has been commingled for many years; therefore, the reservoirs will be considered as one when applicable. Both reservoirs produce by an active water-drive mechanism; consequently, no concrete plans for secondary recovery have been made. Lack of a secondary-recovery program has also reduced interest in unitizing. The purpose of this report is to investigate the feasibility of initiating an alternate gas-water injection secondary-recovery project.

Effective-pay isopach maps of the reservoirs were prepared by using individual well logs and available core data. The reservoir areas were planimetered to determine total volume, and the original oil-in-place was volumetrically calculated from this volume by using average water saturation and porosity values.

Primary oil recovery was determined from individual lease performance, total field performance, and a theoretical fractional flow curve developed from measured relative permeability data.

Secondary oil recovery by alternate gas-water injection was obtained by determining a reservoir recovery factor and multiplying it by the oil-in-place. The reservoir recovery factor was established through the use of three-phase relative permeability data from field cores, plus actual performance of a pilot Tensleep alternate gas-water injection project located in the nearby Little Buffalo Basin Field.

Cash flows were generated for primary and remaining primary plus secondary performance. The incremental difference between the cash flows was used as the secondary recovery cash flow. Undiscounted and discounted profit, payout, return on investment, and annual rate of return on investment were calculated to show the economic feasibility of injecting gas and water as a means of recovering secondary oil.

GEOLOGY

A geologic analysis of the Grass Creek Field was undertaken to define the reservoirs better and to help explain producing characteristics.

Regional Geology

The Big Horn Basin of northwestern Wyoming is primarily a Laramide structural basin; however, the area has been a part of large depositional basins throughout most of geologic history (Thomas, 1965, p. 1867). After the deposition and erosion of the Madison Limestone, the Pennsylvanian Amsden and Tensleep Formations were deposited as the geosyncline, located in Idaho, subsided. The area of the major basin gradually underwent southerly tilting, deposition, erosion, and truncation during Pennsylvanian and Permian time. This tilting resulted in thickening of these formations from northeast to southwest. Some of the eroded clastics may have been redeposited in the southern and western portions of the basin where the thickest Tensleep occurs. This post-Tensleep erosion beveled the Tensleep, with truncation occurring progressively towards the northeast of the Big Horn Basin.

Following the period of emergence caused by the southwest tilting and subsequent erosion, the Phosphoria Formation was deposited on the eroded Tensleep surface. The Phosphoria filled in the topographic lows in the Tensleep surface and caused the gross thickness of the combined formations to be uniform but the Tensleep thickness to vary.

At the beginning of Tertiary time and during the Laramide orogeny, intense movement caused peripheral mountain building, pronounced unconformities around the basin margin, deposition of tertiary sediments, and development of numerous anticlinal folds. The Grass Creek structure is one of these anticlinal folds.

Grass Creek Structure

The Grass Creek Field is located in Hot Springs County, Wyoming, on the southwest side of the Big Horn Basin. Its location, with respect to other major oil fields is shown by Figure 1.

On the surface, Grass Creek is a topographic basin floored with Cretaceous Cody Shale and surrounded by an escarpment of Cretaceous Mesaverde Sandstone. The structure is a northwest-southeast-trending asymmetrical anticline, with its steep flank dipping to the southwest at an angle of 35° to 40°. The steep southwest dip is apparently related to the major thrust fault which, as shown by seismic data, has about 2000 feet of throw. Structural dips are 10° to 15° on the east side of the field (Figures 2 and 3).

Six reservoirs on the structure are oil productive; however, this study deals only with the Phosphoria and Tensleep reservoirs penetrated at a depth of 4000 and 4200 feet, respectively (Figure 4).

Oil-Water Contact

The oil accumulation is hydrodynamically trapped, after gravity segregation, with reasonably well-defined oil-water contacts. The Phosphoria and Tensleep original productive limits were established by drill-stem tests, well-production tests and core analysis from wells located along the oil-water contact.

As exhibited by Figures 2 and 3, a west-to-east tilted oil-water contact in both reservoirs is in accordance with the hydrodynamic gradient of the region. Furthermore, the Phosphoria and Tensleep oil-water contacts indicate that they were originally common to each other.

Stratigraphy

Prior to this study, several wells had been cored, but much of the core was not recovered, not completely analyzed, or not available for visual inspection. Amoco Production Company drilled the Meeteetse 15 Well 25, located in the NE-NW-SW of Section 18, during October, 1970. The well was cored with natural gas to obtain additional geologic and reservoir data for this report. Data from the new core plus other available data were used to develop a better interpretation of lithology, cross-bedding, permeability variation, lenticularity, fracturing, and reservoir fluid saturations (Figure 5).

The Tensleep sand was deposited in a shallow near-shore marine environment above a transitional contact with the underlying Amsden formation (Emmett and others, 1971, p. 162). This transitional contact grades upward from predominantly red shales and carbonates to fine- and medium-grained sandstone. The sandstone contains finely crystalline, dense interbedded dolomite beds, which are more abundant in the lower Tensleep, and frequency of occurrence decreases as sand deposition took place. After the Tensleep sand was deposited, the surface was eroded, leaving the formation 250 feet thick.

Layers of interbedded dolomite within the Tensleep cannot always be correlated from well to well. Some of these dolomite layers grade laterally into sandstone, but in other instances, they remain as almost impermeable beds within the formation (Figure 5). It is quite common for a well to exhibit a tight dolomite lens while an offset completion will have well-developed effective sandstone in the same interval. In the absence of faulting and fracturing, these very low permeability dolomite layers may afford a local effective barrier to vertical communication of formation fluids. A correlation of porosity logs indicates that the Tensleep can be subdivided into an upper and a lower zone which are separated by a field-wide dolomite stringer occurring about 150 feet above the Tensleep base. Visual inspection of cores revealed that vertical fractures predominantly exist in the lower Tensleep (Figure 6). With the lower Tensleep being fractured and the major impermeable dolomite layer being continuous, vertical fluid flow could exist between sandstone zones in the lower Tensleep but probably does not exist between the lower and upper Tensleep. Vertical fractures could also be the explanation for excessive water production from the lower Tensleep.

The two predominant sedimentary structures are (1) thin homogeneous intervals of relatively high and uniform porosity and permeability (Figure 7), and (2) highly cross-bedded zones (Figure 8). There is a general increase in average sand grain size progressing upward in the section as well as an increase in porosity and permeability (Figure 5). The more prominent cross-bedding and poor sorting in the lower Tensleep helps to explain the relatively low permeability. The laminated texture of the cross-bedded zones is due to variation in sand size (Figure 9). Thin, dark zones in the core are only a few millimeters thick and consist of quartz grains ranging in size from fine sand to silt. Between the fine-grained laminations are medium-grained, relatively clean sandstones, 1/4 to 1 inch thick, with good porosity and permeability.

Changes in horizontal permeability can be influenced by cross-bedding in a reservoir. Permeabilities perpendicular and parallel to cross-bedding were measured on Tensleep cores taken from the nearby Little Buffalo Basin Field. At Little Buffalo Basin the average permeability parallel to the bedding was four times greater than that perpendicular to and across the bedding plane. Preferentially, fluid would flow parallel to cross-bedding. If the cross-beds at Grass Creek dip towards the southwest as they do at Little Buffalo Basin, the expected preferential permeability would be oriented northwest-southeast.

As a result of cross-bedding, water influx may progress in the direction of preferential permeability and allow zones of high permeability to be flushed before depletion of less permeable zones. If water breakthrough occurs in a particular zone of producing wells subsequent to injection, the cause could be related to communication through cross-beds with preferential permeability. This rapid breakthrough would necessitate selective zonal injections and selective location of injection wells to maximize oil recovery. Recovery benefits could be gained from injecting a mobil phase such as natural gas which would gradually penetrate the less permeable cross-bedded rock. This natural gas would help displace oil from the numerous cross-bed traps that exist in the reservoir.

The degree of cementation also influences permeability and porosity. Pore-filling cement is of four types: carbonates, silica, anhydrite, and clay particles, in decreasing order of occurrence. Disseminated shale is present in very minor amounts. Pore-filling particles are secondarily developed and not considered to be correlative between wells.

The Permian Phosphoria Formation is a vertically fractured carbonate reservoir which unconformably overlies the Tensleep Sandstone. At Grass Creek it is composed of about 230 feet of brown-to-gray, crystalline-to-microcrystalline, sandy pyritic, phosphatic dolomite. Oil production is limited to the Ervay and Franson members which have been dolomitized and have intergranular porosity developed at the time of dolomitization (Figures 4 and 5). Some secondary porosity development results from fractures and vugs. The Ervay is 40 to 50 feet thick and is more highly dolomitized. This zone contributes a large percentage of the Phosphoria oil. The Franson Member is of lower porosity and permeability and consequently contributes less oil production. The remainder of the Phosphoria contains only thin streaks of oil saturation.

HISTORY OF DEVELOPMENT

Development history was compiled from Amoco Production Company's file. The Phosphoria and Tensleep reservoirs of the Grass Creek Field were discovered in September, 1922. The oil discovery was made by Marathon Oil Company when it deepened its L. U. Sheep Well 13 from the Lakota Sandstone.

During the next four years, Marathon Oil Company and Amoco Production Company drilled nine wells, which were completed open-hole, with production from the Phosphoria and Tensleep commingled in the wellbore. Production rates from the wells varied from 130 to 600 BOPD (barrels of oil per day).

Development of the reservoirs was initially slow because of the limited demand for the sour, viscous, asphalt-base crude. Production from 1922 to 1941 was restricted by market demand. During World War II, the increase in demand for the crude initiated drilling programs. Through 1956, Marathon, Amoco, Husky, Kinney-Coastal, and British American had drilled a total of 57 wells. Fifty of these wells penetrated the Tensleep, but 15 were nonproductive in that reservoir. Six wells were nonproductive in either of the reservoirs.

Six additional wells drilled since 1956 increased the total to 63 wells. Currently, 51 wells are producing from the Phosphoria, and 36 wells are producing from the Tensleep.

Production from all but three wells located within the Tensleep productive area is commingled in the wellbore.

Amoco Production Company drilled the last two wells during 1970. One of these wells (Meeteetse 2-6-7 Well 32) extended the Phosphoria productive limits slightly to the north.

The Phosphoria and Tensleep reservoirs have been operated competitively since discovery, which has resulted in irregular well spacing. Development has taken place on 20-acre spacing in competitive areas but generally on 40-acre spacing in noncompetitive areas.

PRIMARY PERFORMANCE

Prior to calculating recoverable secondary oil, primary oil recovery must be established and this volume compared to the original oil-in-place. The following discusses reservoir fluid properties and reservoir rock characteristics which influence primary performance. Original oil-in-place was calculated by the volumetric method. Primary performance calculations were compared to actual performance to determine reasonable recovery by natural water drive.

Reservoir Fluid Properties

For reservoir engineering calculations, various properties of the crude oil and its associated gas and water must be developed. Fluid properties of the Phosphoria-Tensleep reservoir were experimentally determined or approximated by methods which are sufficiently accurate for most engineering calculations.

A bottom-hole fluid sample of Tensleep oil was collected by Amoco Production Company from its Meeteetse 2-6-7 Lease, Well 30 on June 27, 1951. The sample was collected at 1065 psia while the reservoir was above the bubble-point pressure. Phosphoria oil properties were not determined; however, fractional distillation data indicate that the properties of oil from the Phosphoria and Tensleep reservoirs are the same.

Oil from the Tensleep reservoir is highly undersaturated with gas. The saturation pressure is 140 psia at the bottom-hole temperature of 119°F. The solution gas-oil ratio is only 24.3 standard cubic feet of gas per barrel of residual oil. Oil gravity is 24.7° API at 60°F and 14.7 psia. The formation volume factor, at the bubble-point pressure, is 1.039 reservoir barrels per STB and decreases to 1.03 reservoir barrels per STB at the original 1275 psi reservoir pressure. Oil viscosity increases from 13.0 centipoises, at the bubble-point pressure, to 18.7 centipoises at atmospheric pressure and the bottom-hole temperature of 119°F. Compressibility of the subsurface oil is 7.04 x 10^{-6} volume per volume per psi (Harstine, 1951, p. 1).

Gas liberated from the oil was not analyzed because of the small volume and the low bubble point pressure. The average producing pressure will never decline below the bubble-point pressure; therefore, no free gas will ever exist in the reservoir unless it is injected.

For the purpose of determining the reservoir space occupied by injected natural gas, gas deviation and volume factors were calculated. The gas deviation factor was determined from an analysis of Oregon Basin natural gas, which is the most logical source of natural gas (Figure 11). By use of the calculated gas deviation factors, average reservoir temperature and various reservoir pressures, gas-volume factors were calculated with the following formula (Figure 12):

$$Bg = \frac{5.04\ Z\ T_R}{P_R}$$

where Bg = gas volume factor, reservoir bbl./SMCF

Z = gas deviation factor, fractional

T_R = average reservoir temperature, °R

P_R = average reservoir pressure, psig

The gas viscosity curve shown on Figure 13, was developed by using Carr's gas viscosity correlations (Craft and Hawkins, 1959, p. 265).

Reservoir Rock Characteristics

Rock Characteristics were determined to use in calculating the original oil-in-place and to understand better the flow of fluids in the reservoirs.

Thickness: The Phosphoria and Tensleep formations are 230 and 250 feet thick, respectively. Figure 10 shows typical well logs used to determine effective pay. Based on a correlation of core data and well logs, a 12 percent porosity cut-off was used for the Phosphoria and a 7 percent porosity cut-off was used for the Tensleep. The porosity cut-offs are supported by Figures 14 and 15, which show that these porosities correspond to 1 millidarcy permeability. By use of individual well effective-pay values, isopach maps were prepared (Figures 16 and 17). The average net thickness of each reservoir was calculated after planimetering the isopach maps. Effective-pay thickness for the Phosphoria and Tensleep is 36.4 and 87.3 feet, respectively.

Porosity: Porosities of the reservoirs were determined by analysis of core data (Figures 14 and 15). Porosity of the Phosphoria averaged 18.5 percent as compared to an average 14.3 percent porosity for the Tensleep.

Permeability: The Dykstra-Parson's permeability variation, as shown by Craig (1971, p. 65), for both reservoirs was calculated (Figures 18 and 19). The Phosphoria is a very heterogeneous reservoir with a permeability variation of 0.77 and a permeability range from 1 to 152 millidarcies. A permeability variation of zero indicates a homogeneous system as compared to a permeability variation of 1.0, which indicates a completely heterogeneous system. The Phosphoria geometric mean permeability is 9.0 millidarcies. This mean permeability corresponds to the average 18.5 percent porosity.

Tensleep permeabilities range from 1 to 1150 millidarcies with a permeability variation of 0.53. The Tensleep reservoir must also be considered heterogeneous. The geometric mean permeability is 75 millidarcies which correlates with an average 14.3 percent porosity.

Two-phase and three-phase relative permeability data were obtained on Tensleep core samples taken from the Meeteetse 15 Well No. 25 during October, 1970. The core was cut using natural gas to preserve the relative permeability characteristics and fluid saturations as much as possible. These data are shown by Figures 20 and 21. The water-oil relative permeability data are typical of oil-wet sandstones (Archer and Doerr, 1971, p. 1).

The flow properties of Grass Creek Tensleep cores were found to be similar to other Tensleep cores, especially those of Little Buffalo Basin. The gas-oil test results show that the cores are more efficient in the displacement of oil by gas than any other Tensleep sandstone sample tested by Amoco Production Company. These results indicate a very uniform pore-size distribution of the test samples.

The water-oil relative permeability data were obtained to analyze the feasibility of using alternate gas-water injection to increase ultimate recovery from the Tensleep reservoir. The three-phase tests show that, when water, gas, and oil are flowing, the two nonwetting phases (gas and water) interfere with each other.

Figure 21 shows a comparison of permeability to water with and without gas present. The permeability of water, with 10 to 12 percent pore volume gas saturation present, is shifted to the right of the water permeability curve with no gas present. The shift in relative permeability data indicates more efficient displacement of oil by gas and water.

<u>Oil and Water Saturations</u>: Permeability of cores cut with oil or gas was plotted versus irreducible water saturation to determine

the average water saturation of the reservoirs (Figure 22). The geometric mean permeability indicates that the water saturation of the Tensleep and Phosphoria reservoirs was 4 percent and 20.5 percent, respectively. No gas saturation existed, so the remaining pore space was occupied by oil.

Oil-In-Place

The oil-in-place was calculated by the volumetric method using previously established reservoir parameters. The basic equation for calculating oil-in-place is

$$N = 7758\ Ah\ \phi\ (1-Swi)/Boi$$

where A = reservoir area, acres
h = effective pay thickness, feet
ϕ = average porosity, fraction
Swi = average initial water saturation, fraction
Boi = initial oil formation volume factor, volume at reservoir conditions per volume at standard conditions.

Effective-pay isopach maps were planimetered to determine that the Phosphoria and Tensleep reservoir volumes were 83,610 and 122,079 acre-feet respectively. With these volumes, the original oil-in-place in the Phosphoria reservoir was calculated to be 92,531,200 STB, and the Tensleep reservoir contained 126,107,000 STB.

Water-Drive Recovery

Primary performance calculations were made to establish how much of the oil-in-place would be recovered by the natural water-drive. The Phosphoria and Tensleep reservoirs have produced by a natural water-drive, and production has been commingled since discovery. Because production from each reservoir is unknown, it is necessary to treat both as a single reservoir when making calculations. Both reservoirs were initially very undersaturated with gas. The reservoir pressure has declined from 1275 to 600 psia compared to the bubble-point pressure of 140 psia. Water influx will maintain the pressure above the bubble-point pressure.

Water influx was approximated by using van Everdingen and Hurst solutions to the diffusivity equation as shown by Craft and Hawkins (1959, p. 218). The water influx equations used are

$$T_D = 6.323 \times 10^{-3} \frac{K\ T}{\phi\ \mu Ce\ r_w^2}$$

$$B = \frac{1.119\ \phi\ Ce\ r_w^2\ h\ \theta}{360}$$

$$We = B \Sigma \Delta P Q(t)$$

where T_D = dimensionless time

K = permeability, millidarcies

T = real time, days

ϕ = porosity, fractional

μ = viscosity, centipoises

Ce = compressibility, vol/vol/psi

r_w = reservoir radius, feet

h = reservoir thickness, feet

θ = angle subtended by reservoir circumference, degrees

We = water influx, bbl

B = water influx constant, bbl/psi

ΔP = reservoir boundary pressure drop, psi

$Q(t)$ = dimensionless influx

The cumulative water influx to July, 1971, was calculated to be 53.5 million barrels. The current rate of water influx is 20,900 BWPD. These water-influx values were determined by using an influx constant equal to 1,690 bbl per psi. The influx constant was derived by estimating that water influx was predominantly from the western edge and that the major water flow was across only one-third of the reservoir external radius. This assumption was based on reservoir pressure data and was necessary to obtain a pressure history match.

A continuous system modeling program was written to calculate the future performance of the combined reservoirs. For the primary recovery calculation, a constant rate of fluid withdrawal was assumed. The constant fluid withdrawal rate and the producing water-oil ratio were then used to calculate the reservoir pressure. This calculated reservoir pressure was used to determine the natural water influx.

The program uses the following material balance equation which applies for a reservoir producing above the saturation pressure (Craft and Hawkins, 1959, p. 136).

$$N \; Boi \; Ce \; \Delta P = Np \; Bo - We + Bw \; Wp$$

where N = initial oil-in-place, STB
Boi = initial oil formation volume factor, reservoir bbl/STB
Ce = effective compressibility, vol/vol/psi
ΔP = reservoir pressure change, psi
Np = cumulative oil produced, STB
Bo = oil formation volume factor, reservoir bbl/STB
We = cumulative water influx, reservoir bbl.
Bw = water formation volume factor
Wp = cumulative water produced, STB

Results of the primary performance calculations are shown on Figure 23. Calculations indicate that a total 56,930,000 STB of oil will be recovered from both reservoirs if operations continue as they have in the past. Primary recovery will be 26 percent of the original oil-in-place at an economic limit of 425 BOPD.

Buckley-Leverett's frontal-advance theory as shown by Smith (1966, p. 148) was used to estimate the volume of oil which would theoretically be recovered by natural water drive from a homogeneous Tensleep system.

By use of the above method and the Tensleep water-oil relative permeability, a fractional flow curve was drawn (Figure 24). In constructing the fractional flow curve, gravity and capillary effects were neglected. At 100 percent volumetric coverage, the fractional flow curve graphically shows

1. Tensleep oil recovery at breakthrough would be 45.6 percent of the oil-in-place.
2. Tensleep oil recovery at 96 percent water production (WOR=24:1) would be 50.9 percent of the oil-in-place.

To approximate recovery based on the 0.53 permeability variation and the 1.25 water-oil mobility ratio, Craig (1971, p. 114) shows the theoretical recovery should be multiplied by $(1-V^2)/M$: where V = permeability variation

$$M = \frac{K_{rw}}{\mu_w} \frac{\mu_o}{K_{ro}}, \text{ the mobility ratio.}$$

Tensleep primary recovery by water-drive then becomes 36,950,000 STB or 29.3 percent of the original oil-in-place.

The difference between the combined Phosphoria-Tensleep recovery and the calculated Tensleep recovery is primary recovery from the Phosphoria reservoir. This difference shows the Phosphoria will produce 19,981,000 STB or 21.6 percent of the oil-in-place.

SECONDARY RECOVERY PROJECTION

With the Grass Creek reservoirs being flooded by the natural water drive, more emphasis must be placed on an improved recovery technique, if oil recovery is to be increased. Based on the success of gas-water flooding other oil-wet reservoirs, this same process should be seriously considered for Grass Creek.

Alternate gas-water injection at the nearby Little Buffalo Basin Field was evaluated by pilot performance. Emmett and others (1971) showed that an additional 9 percent of the original oil-in-place would be recovered by the injection of gas and water. Little Buffalo Basin is now under field-wide gas-water injection.

The lithology of Little Buffalo Basin is very similar to that which exists at Grass Creek. The reservoirs in both fields are characterized by numerous individual dolomite and sandstone stringers, many of which are highly cross-bedded with extreme ranges in vertical and lateral permeability.

Experience with alternate gas-water injection has shown that very heterogeneous oil-wet reservoirs with poor vertical sweep, under conventional waterflood or natural water drive, can have displacement efficiency substantially improved by using the two-phase flow characteristics of the alternate gas-water injection process.

The following discusses the secondary recovery potential, laboratory tests run to show improvement in displacement efficiency, injection and production forecast, water and gas requirements, and economics of conducting an alternate gas-water injection project.

Primary performance indicates that 56,930,000 STB of oil will be recovered by the natural water drive. The difference between the original oil-in-place and recoverable oil shows 161,708,000 STB of oil will remain in place unless an improved producing technique is adopted. The following is a discussion of how the secondary recovery projection was made.

Laboratory Tests

In oil-field miscible drive or waterflood programs, alternate or simultaneous gas-water injection is commonly used as a means of improving the overall areal and vertical sweep of the recovery process. Relative permeability tests on oil-wet samples by Schnieder (1971, p. 2) have shown that water and gas injected together interfere with each other and cause the combined displacing phase to be less mobile. This combination results in a more favorable mobility ratio during flooding operations. Mobility is a function of the permeability and viscosity ratio. A reduction in the effective permeability or an increase in the effective viscosity of the driving phase theoretically results in improved flood performance. Three-phase relative permeability data and field tests in oil-wet reservoirs have shown that injecting water after gas in an alternating manner can reduce the mobility ratio from 25 to 50 percent.

Laboratory tests and calculations by Fitch (1966, p. 2) also show that the reservoir with a high gas-to-water mobility ratio and a large decrease in water-to-oil mobility ratio, as a result of trapped gas, should exhibit good alternate gas-water injection performance from a vertical and areal sweep improvement standpoint. Of course, good performance will be realized only if there is no drastic loss in water permeability.

The conditions under which gas-water injection is found to be most favorable are in reservoirs where a high degree of lenticularity, cross-bedding and stratification exist and mobility ratios range from 0.2 to 2.5. The factors which exert the greatest influence on oil recovery are relative permeability characteristics, fluid viscosities, and reservoir heterogeneity. The Grass Creek reservoirs as well as many other Rocky Mountain reservoirs have characteristics which are conducive to improved recovery by alternate gas-water injection.

Three-phase relative permeability tests on oil-wet Grass Creek Tensleep cores have demonstrated the beneficial effect of a trapped gas saturation on oil recovery by alternate gas-water injection (Schnieder, 1971, p. 2). Conclusions drawn from these tests were that relative permeability to oil (the wetting phase) when oil, gas, and water are present is a function of only the oil saturation. The relative permeability to water (a nonwetting phase) at a given water saturation when water, oil, and gas are present is significantly lower than that obtained when only oil and water are present. These permeability characteristics indicate that when a trapped-gas saturation is present and maintained, a smaller volume of injected water or natural water influx will be required to recover a given amount of oil as compared to waterflooding with no gas saturation present. Laboratory work by Schnieder shows continued injection of water after terminating gas injection resulted in increasing water saturations and increasing water relative permeabilities. The increasing water relative permeabilities indicate that a gas saturation must be maintained to gain benefit from the relative permeability characteristics. One purpose of injecting gas and water is to take advantage of the three-phase flow restriction and to interrupt the flow of the continuous phase. This interruption reduces the tendency for fingering or channeling to occur.

Craig (1971, p. 75) pointed out that because of capillary effects water will tend to be repelled and will not enter low permeability oil-wet strata. Gas being less viscous than water and slightly soluble with oil would tend to enter the low permeability strata more readily than water. The net result would be better vertical coverage in the injection wellbore and better displacement efficiency in the reservoir. Selective completion of a Little Buffalo Basin well has shown that 85 percent vertical coverage of the Tensleep reservoir can be attained when injecting natural gas.

The improved oil recovery by gas-water injection is therefore attributed to greater displacement efficiency because of the lower gas and water mobility, greater sweep efficiency because of the lower mobility ratio between relatively viscous oil and the displacing phase, establishment of a trapped-gas saturation in the reservoir pore space; and some reduction of oil viscosity which was due to gas going into solution with the undersaturated crude. The reduction in oil viscosity results in improved crude-flow characteristics.

To demonstrate partial benefits of gas-water injection, a Tensleep fractional flow curve was developed (Figure 24). The three-phase relative permeability data shown on Figure 21 were used to construct the fractional flow curve. Analysis of Figure 24 indicates that 54 percent of the original oil-in-place can theoretically be recovered by gas-water injection as a result of three-phase relative permeability characteristics.

Burcik (1957, p. 128) shows that, if an additional 20 cubic feet of gas per barrel of reservoir crude eventually goes into solution, the crude viscosity would be reduced from 14.2 to 12 centipoises. The viscosity reduction would result in a mobility ratio decrease from 1.25 to 1.03. By use of this lower mobility ratio and the 0.53-permeability variation, the 54-percent recovery by gas-water drive is reduced to 37.7 percent of the original oil-in-place. The difference between water-drive recovery and recovery by gas-water drive is then 8.4 percent.

This incremental recovery agrees with actual performance from the Little Buffalo Basin Field and Kyte (1956, p. 220), who shows a recovery improvement of 8 to 10 percent of pore volume from oil-wet cores and viscous oils. It is therefore concluded that an increase of 8 percent of the original oil-in-place or 10,100,000 STB is a reasonable estimate of recoverable oil from the Grass Creek Tensleep reservoir.

Three-phase relative permeability data are not available to calculate secondary recovery from the Phosphoria reservoir. An estimate was made by assuming that secondary recovery would be proportional to incremental recovery from the Tensleep and the permeability variation that exists in the Phosphoria. The estimated secondary oil recovery from the Phosphoria is 4 percent of the original oil-in-place or 3,700,000 STB.

Injection and Production Forecast

The continuous system modeling program discussed on page 19 and production performance from the Little Buffalo Basin Field were used to determine how much fluid should be injected and what performance could be expected.

Primary performance indicates the Grass Creek Field has a remaining primary life of 22 years. To increase the present worth of the primary and secondary oil, production should be accelerated.

Based on the operation of the Little Buffalo Basin Field, the best and most practical method of accelerating oil production is to drill additional wells. Oil production from Little Buffalo Basin has been doubled as a result of drilling additional wells during the past several years. It is reasonable that Grass Creek production can also be doubled by drilling 16 additional producing wells.

To make the necessary injection and production forecasts, it was estimated that Grass Creek total fluid withdrawals would be increased from 19,000 to 38,000 BFPD and held constant. Sufficient water would then be injected to maintain the current reservoir pressure at 600 psi. It was also estimated that gas injection would cause the field water-oil ratio to remain constant during the first six years as did gas injection at Little Buffalo Basin.

The modeling program shows that a maximum 5,300 BWPD will have to be injected to operate the reservoirs as specified above. This water requirement is low and not practical when one considers that 10 injection wells and a nine-spot pattern was selected to give good reservoir coverage. To be practical and to operate a gas-water injection project properly, the water injection facility should be capable of injecting 10,000 BWPD or 1,000 BWPD per injection well. The above calculations are based on water injection only and do not consider gas injection.

Natural gas requirements were based on injecting a 10-percent pore volume. The natural-gas fractional-flow curve shows that this is a reasonable amount of gas to inject and still control gas cycling (Figure 25). The total pore volume of the two reservoirs is 255.5 million reservoir barrels. Natural gas required for a 10-percent saturation would be 25.55 million barrels or 5.6 billion cubic feet at 600 psi.

Operating experience at Little Buffalo Basin indicates that 50-percent of the injected gas will have to be recycled during the next 10 years before injection of the total gas volume can be accomplished. A gas-injection facility capable of processing 3.0 million cubic feet of gas per day will be required for the Grass Creek project.

The production forecasts developed for primary and secondary recovery operations are shown on Figure 23. The primary oil producing rate and water-oil ratio agree with the previous 8.5 years of performance. The primary plus secondary oil producing rate forecast is based on doubling the current withdrawal rate and maintaining the water-oil ratio constant for six years, as previously discussed. Oil production then declines exponentially, and total fluid production remains constant at 38,000 BFPD until all reserves are recovered. The incremental difference between these two oil-rate forecasts represents 13.8 million STB of oil recoverable by drilling 16 additional producing wells and by conducting the proposed alternate gas-water injection project.

Water and Gas Supply

To initiate a secondary recovery project, a water source must be developed, and gas must be transported to the field.

Two sources of water exist. The Phosphoria and Tensleep reservoirs produce 15,500 BWPD. This produced water should be disposed of by reinjection. An alternate supply of water could be obtained from the Madison Formation. The Curtis reservoir is being waterflooded by using water which is produced from three Madison supply wells. Madison water is also being used to flood other Big Horn Basin reservoirs. The quantity and quality of available water is adequate to supply the amount needed.

Natural gas has been injected at the Little Buffalo Basin Field since 1961. The gas is transported from the Oregon Basin Field by Cody Gas Company through a 6- and 8-inch-diameter line. A 4-inch-diameter gas transportation line continues on to the Grass Creek Field. The above pipeline system has sufficient capacity to deliver the required 3,000 MCFD of gas to Grass Creek in addition to the volume of gas that will ever be used at Little Buffalo Basin.

Economics

The feasibility of drilling additional wells and using gas-water injection as a secondary recovery process is dependent upon favorable economics. To establish the economics, the undiscounted after-tax annual cash flows for primary operations and primary-plus-secondary recovery operations were calculated for years after January 1, 1972. All necessary investments and operating costs for each case were included. The difference between the two undiscounted cash flows is the undiscounted profit realized from drilling 16 producing wells, installing the necessary equipment, and operating the secondary recovery project.

The undiscounted cumulative cash flow is shown on Figure 26. The maximum negative cash flow is $1,486,000 if all investments are made during the year 1972. A payout of the project would occur in November, 1973. The ultimate profit would be $17,800,000 over 22 years. Present worth of this amount discounted at 10 percent is $9,381,000. A return on investment of 11.98 would be realized. Here, return on investment is defined as the ultimate profit divided by the maximum negative cash flow. The average annual rate of return on the investment would be 78.5 percent.

The initial investment for drilling 16 producing wells is $1,600,000, 40 percent of which is tangible. A tangible investment of $450,000 for the water-and-gas injection facility is required during 1972, and an additional $80,000 tangible investment for recycle gas equipment is required during 1973. The total investment is $2,130,000.

Data used to develop the above economics are as follows:

Working Interest	100%
Royalty	12.5%
Oil Price	$2.94/bbl.
Gas Price	$0.25/SMCF
Lifting Cost	$400,000/Year
Depreciation	14.28%/Year
State Tax Rate	7.4%
Federal Income Tax Rate	50%

CONCLUSIONS

This engineering study was made to determine the feasibility of using the alternate gas-water injection process to increase oil recovery from the Phosphoria and Tensleep reservoirs of the Grass Creek Field. Conclusions developed from this study are:

1. The alternate gas-water injection process is feasible.
2. Oil recovery by the natural water drive will be 56,930,000 STB.
3. Oil recovery by supplementing the natural water drive with alternate gas-water injection will be 70,730,000 STB.
4. The proposed $2,130,000 project will pay out in 1.95 years, and a return on investment of 11.98 will be realized. An undiscounted after-tax profit of $17,800,000 will be gained, which is equal to $9,381,000 when it is discounted at 10 percent. The average annual rate of return will be 78.5 percent.

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APPENDIX

Page

Figures

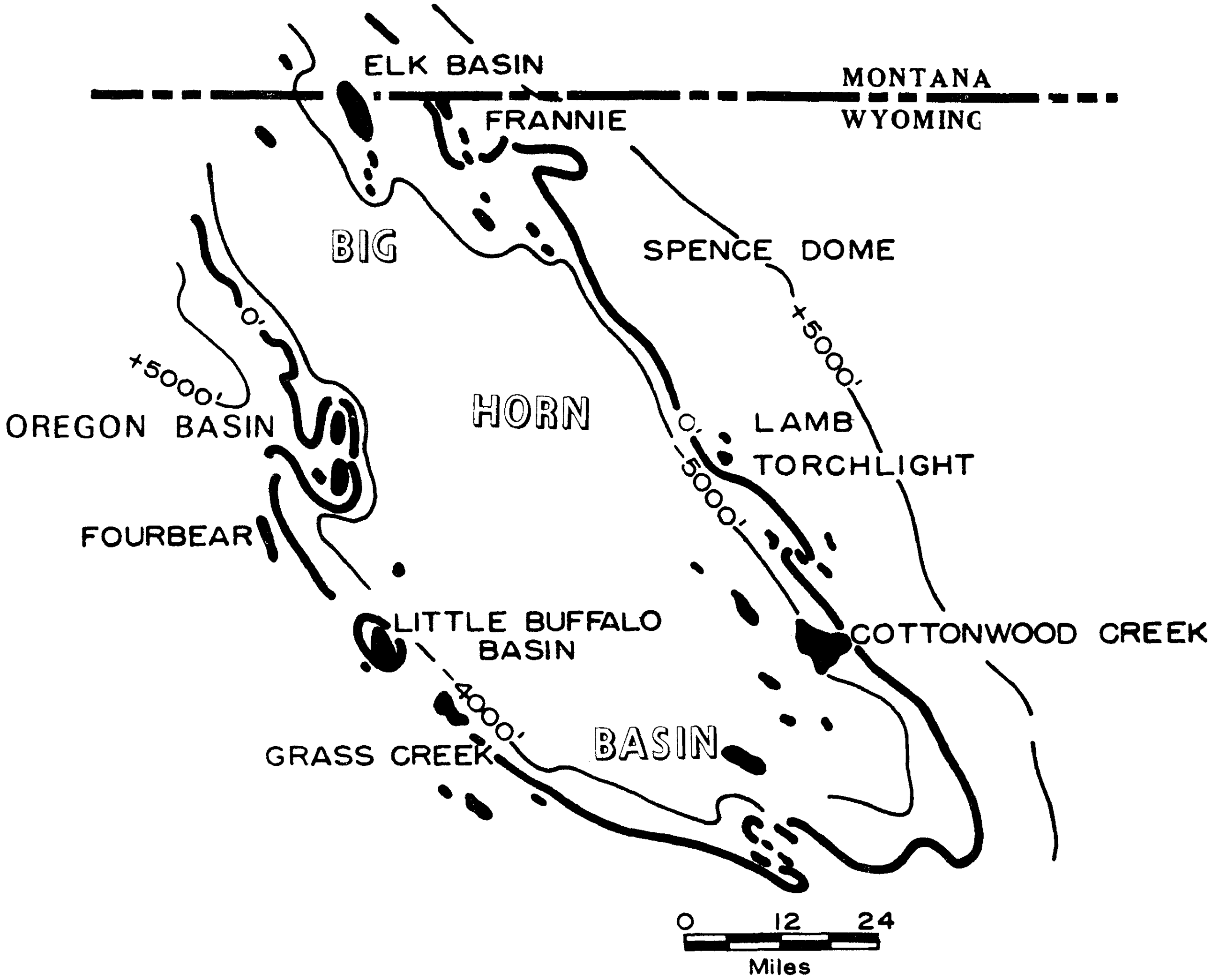


Figure 1: Location Map Of Grass Creek Field Contoured On The Tensleep Formation

(Modified From Emmett etal.)

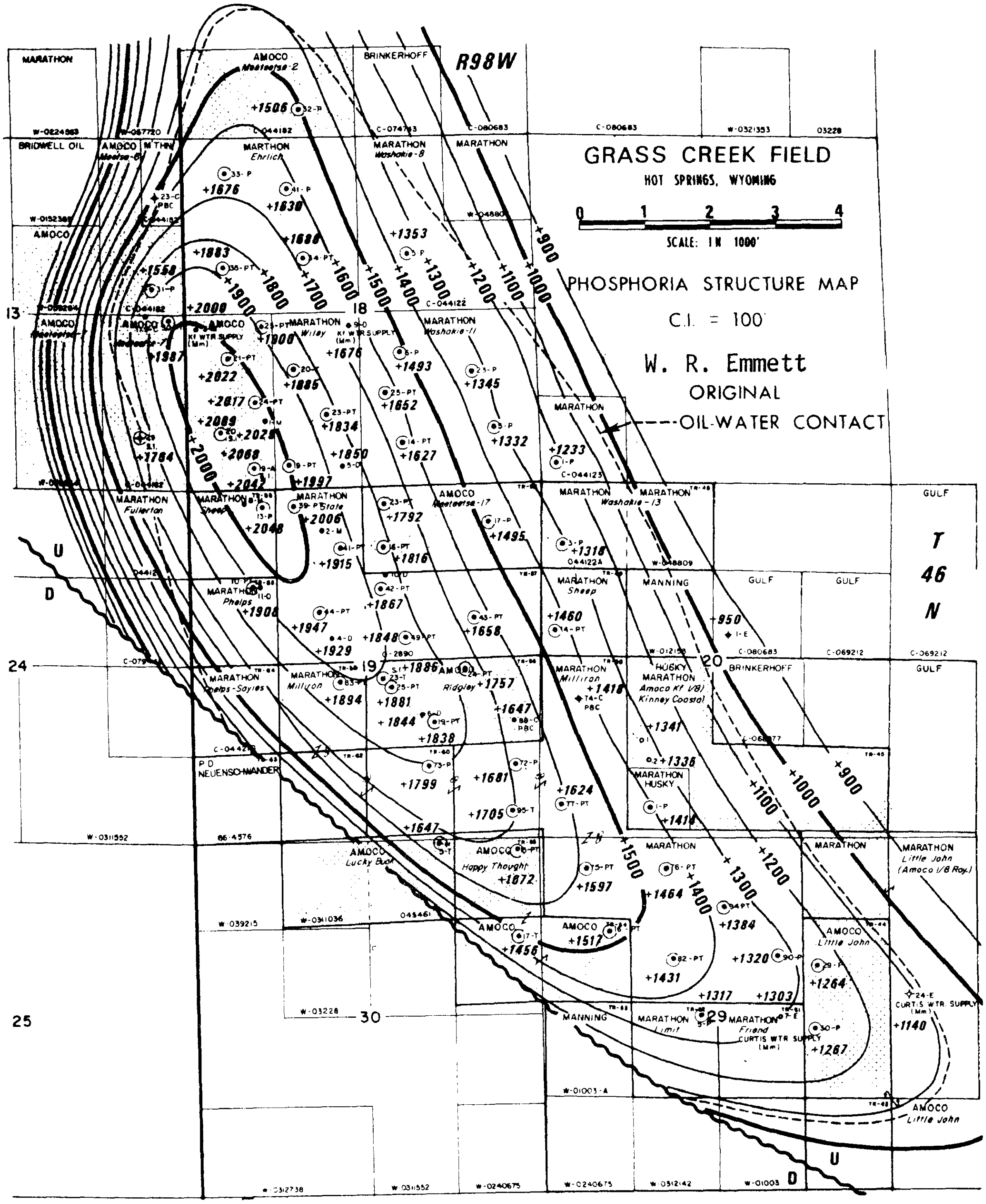


Figure 2: Grass Creek Structure Map Contoured On The Phosphoria Formation

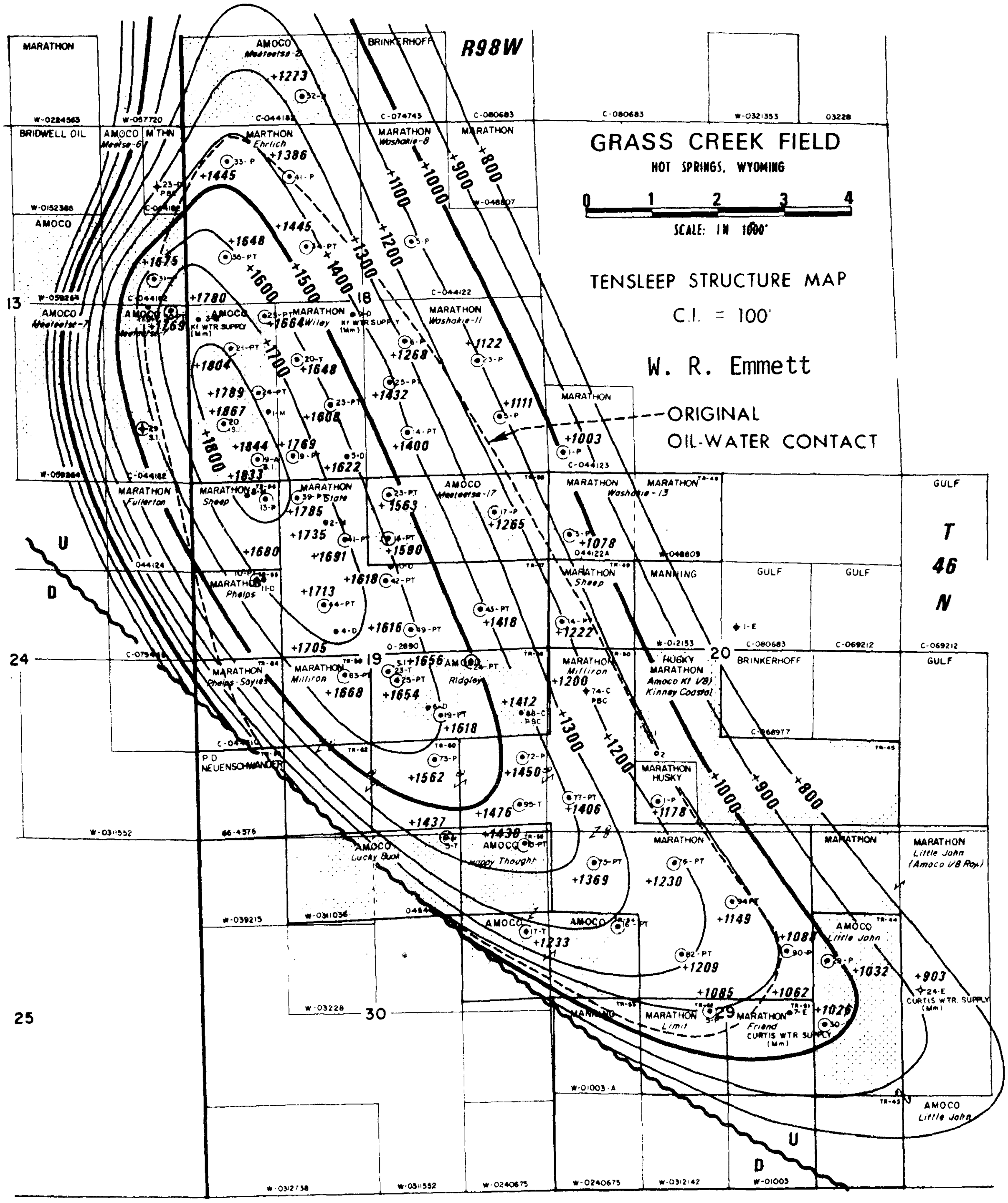
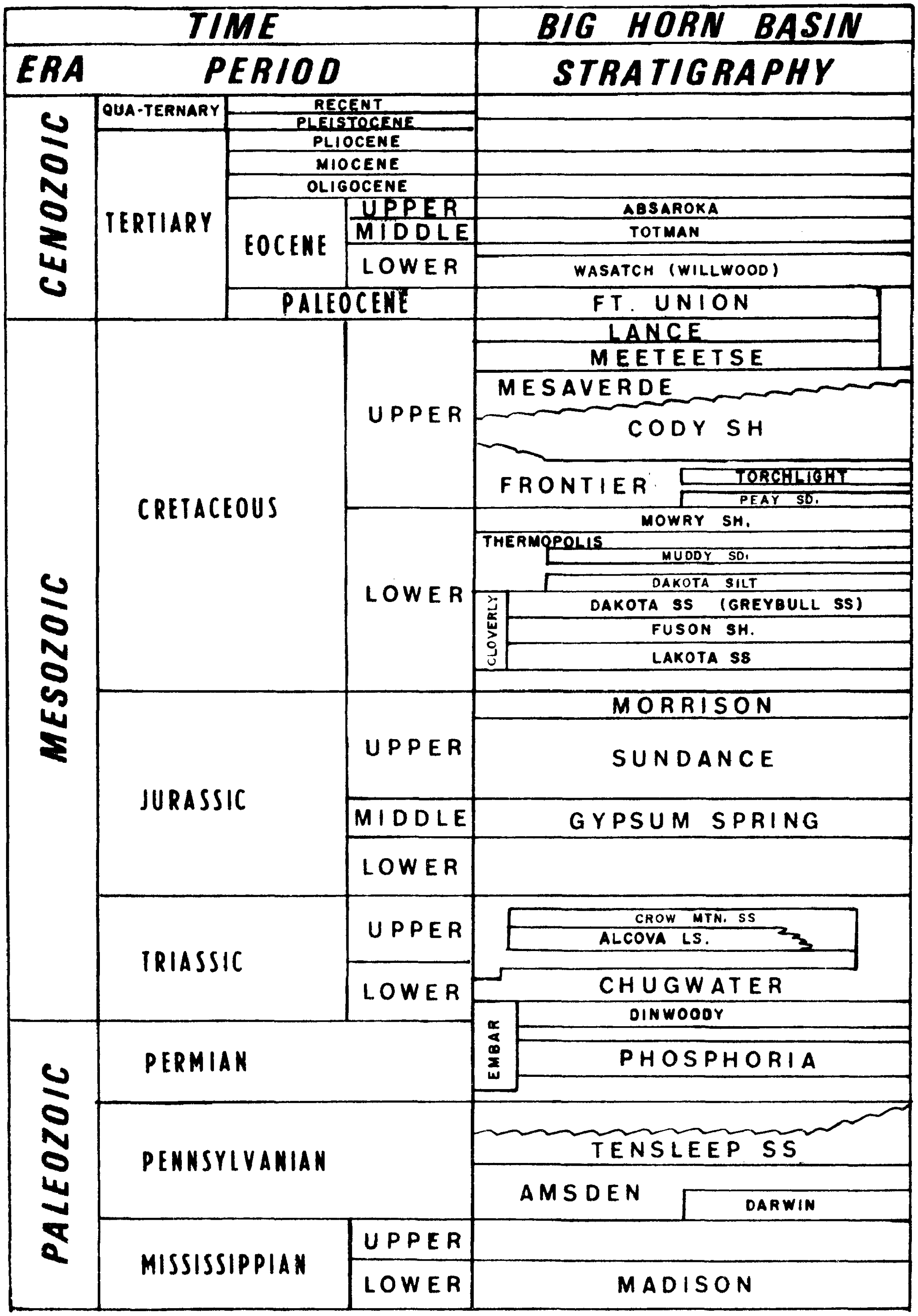


Figure 3: Grass Creek Structure Map Contoured On The Tensleep Formation



TIME				BIG HORN BASIN		
ERA	PERIOD			STRATIGRAPHY		
CENOZOIC	QUA-TERNARY	RECENT				
		PLEISTOCENE				
	TERTIARY	PLIOCENE				
		MIOCENE				
		OLIGOCENE				
		EOCENE	UPPER		ABSAROKA	
			MIDDLE		TOTMAN	
			LOWER		WASATCH (WILLWOOD)	
		PALEOCENE			FT. UNION	
MESOZOIC	CRETACEOUS		UPPER		LANCE	
					MEETEETSE	
					MESAVERDE	
					CODY SH	
					FRONTIER	TORCHLIGHT
						PEAY SD.
			LOWER		MOWRY SH.	
					THERMOPOLIS	MUDDY SD.
						DAKOTA SILT
				CLOVERLY	DAKOTA SS (GREYBULL SS)	
					FUSON SH.	
					LAKOTA SS	
	JURASSIC		UPPER		MORRISON	
					SUNDANCE	
			MIDDLE		GYPSUM SPRING	
			LOWER			
	TRIASSIC		UPPER		CHUGWATER	CROW MTN. SS
						ALCOVA LS.
			LOWER		CHUGWATER	
PALEOZOIC	PERMIAN			EMBAR	DINWOODY	
					PHOSPHORIA	
	PENNSYLVANIAN				TENSLEEP SS	
					AMSDEN	DARWIN
	MISSISSIPPIAN		UPPER			
			LOWER		MADISON	

Figure 4: Stratigraphic Section of The Big Horn Basin

(Modified From Amoco Production Company's Stratigraphic Correlation Chart.)

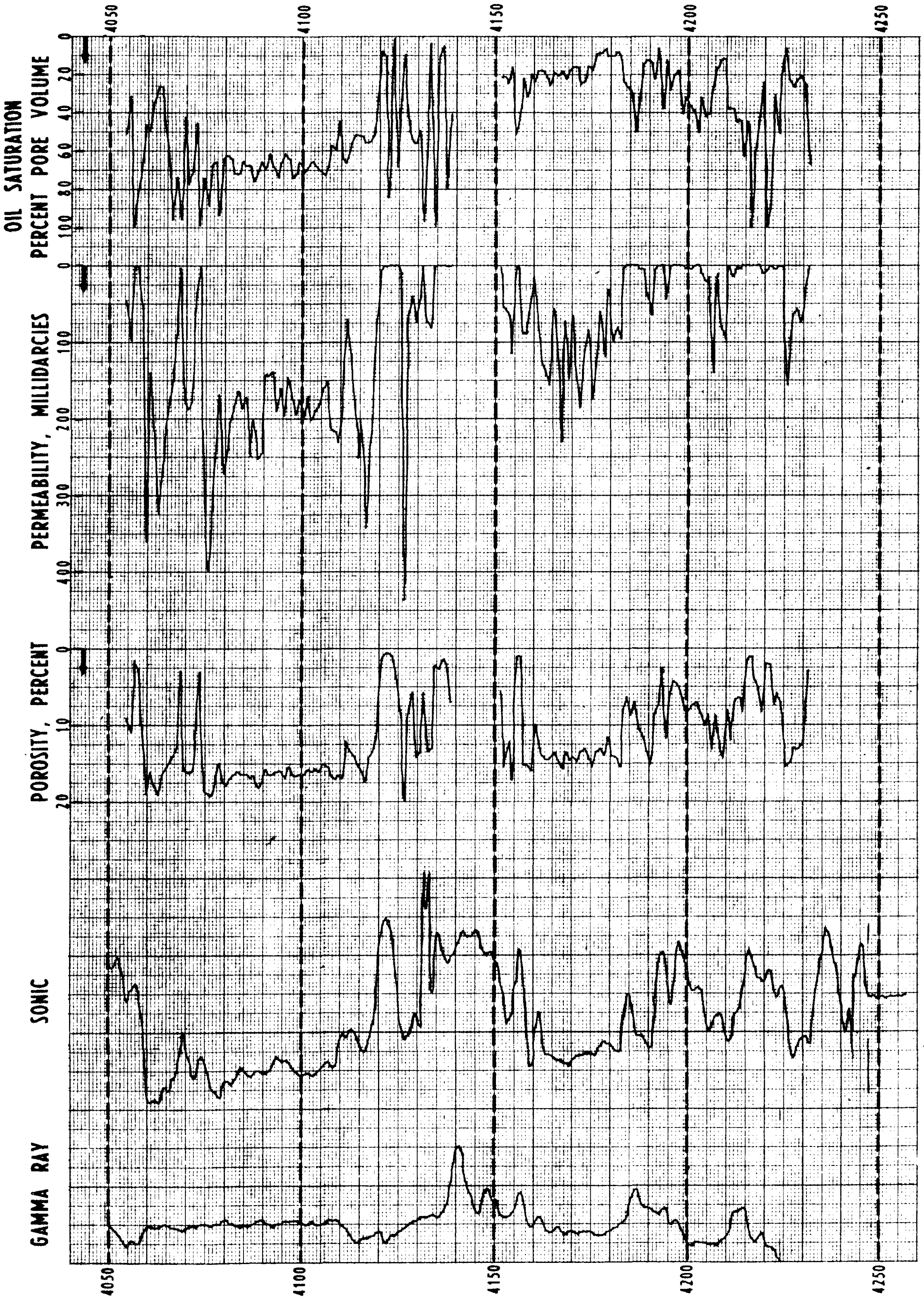


Figure 5 : Grass Creek Meeteetse 15 Lease—Well 25 Tensleep Core-Log Correlation

Figure 6: Grass Creek Core Sample of Lower Tensleep Showing Vertical Fractures

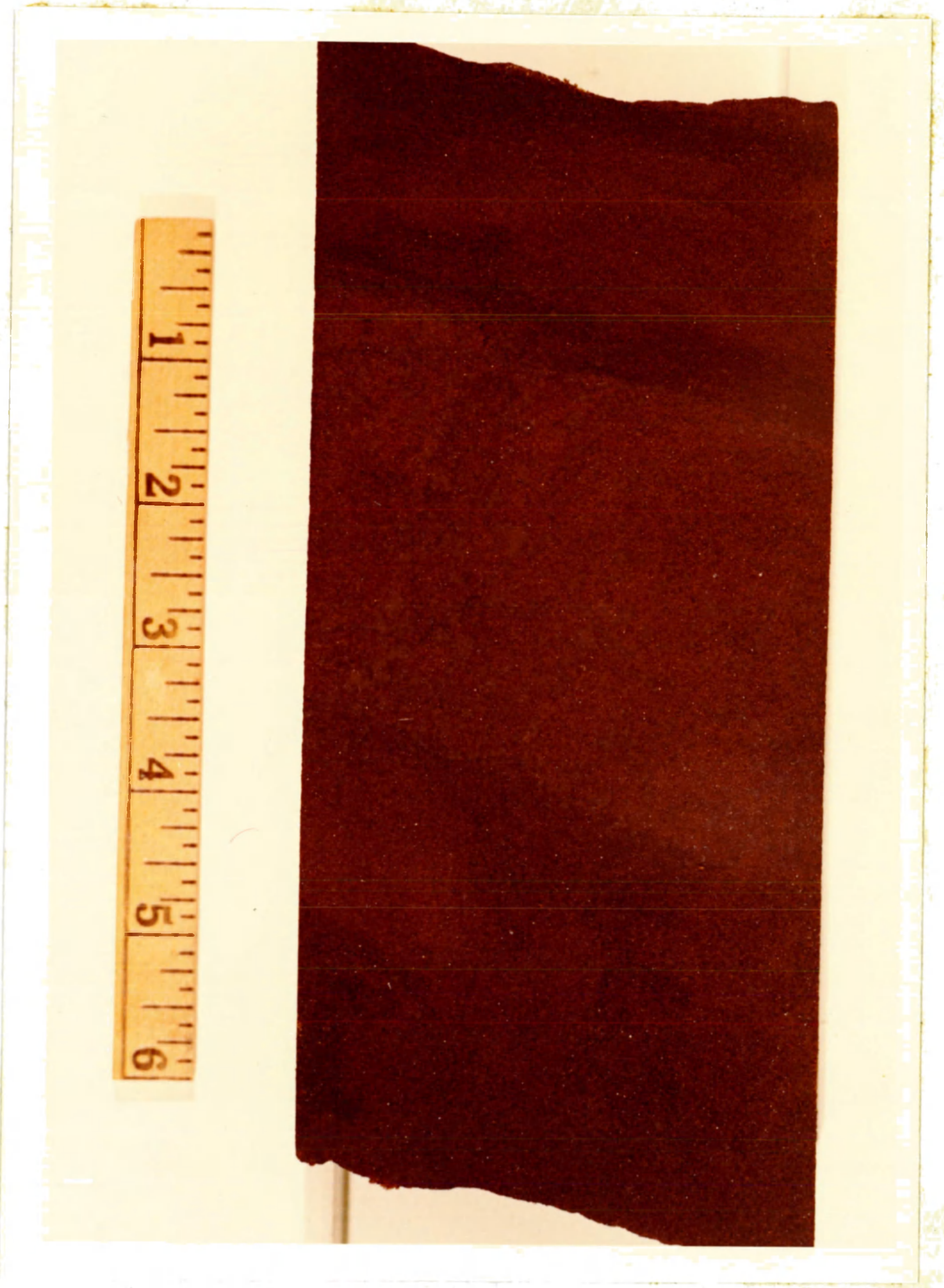


Figure 7: Grass Creek Core Sample Of Tensleep Intervals Of Homogeneous Sand

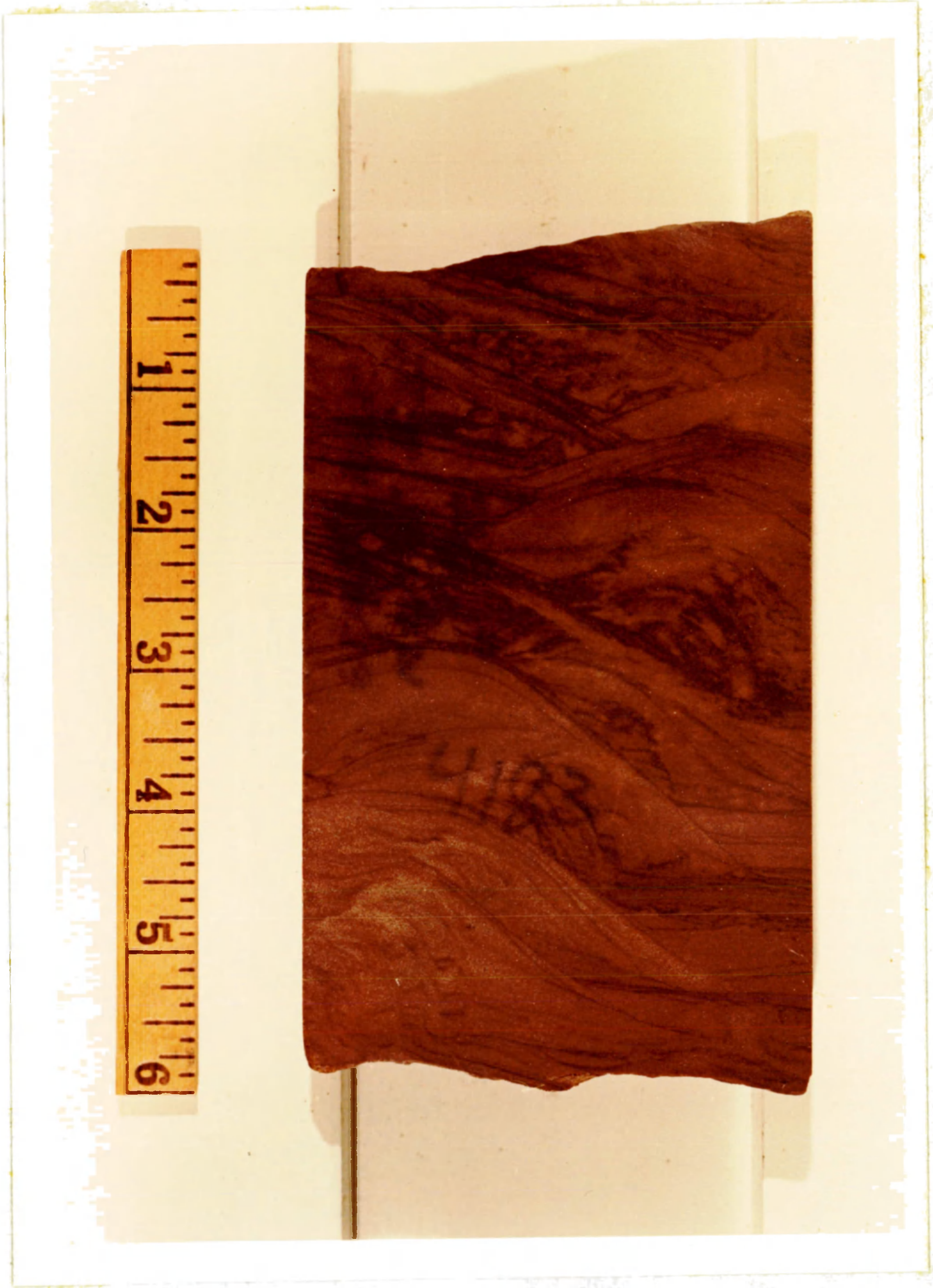
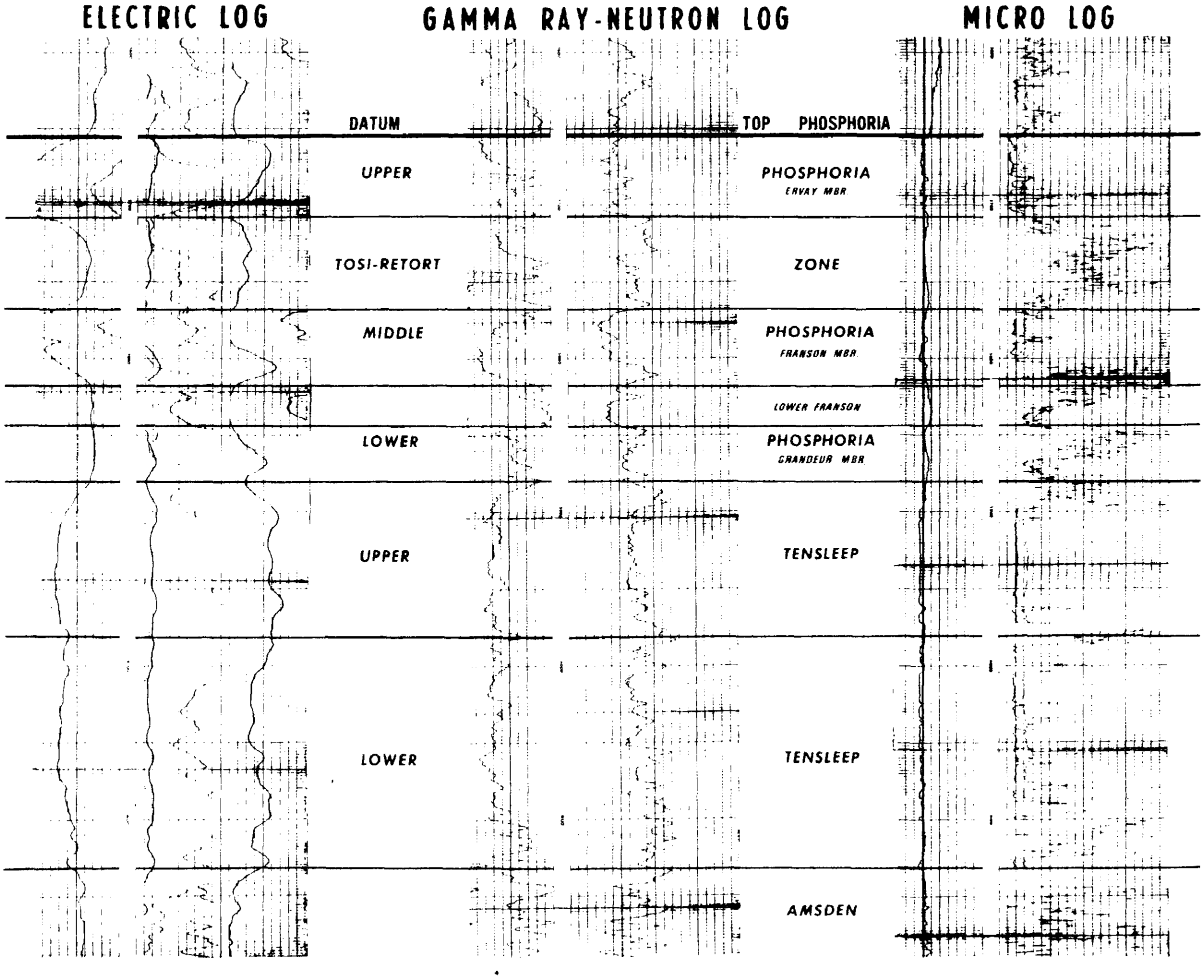


Figure 8: Highly Cross-Bedded Grass Creek Tensleep Sand

Figure 9: Grass Creek Tensleep Sand Showing Laminated Texture of The Cross-Bedded Zones.



NE SW SW SEC. 18 T46N-R98W

Figure 10: Typical Grass Creek Phosphoria-Tensleep Logs From Pre-Tensleep Unit No. 1

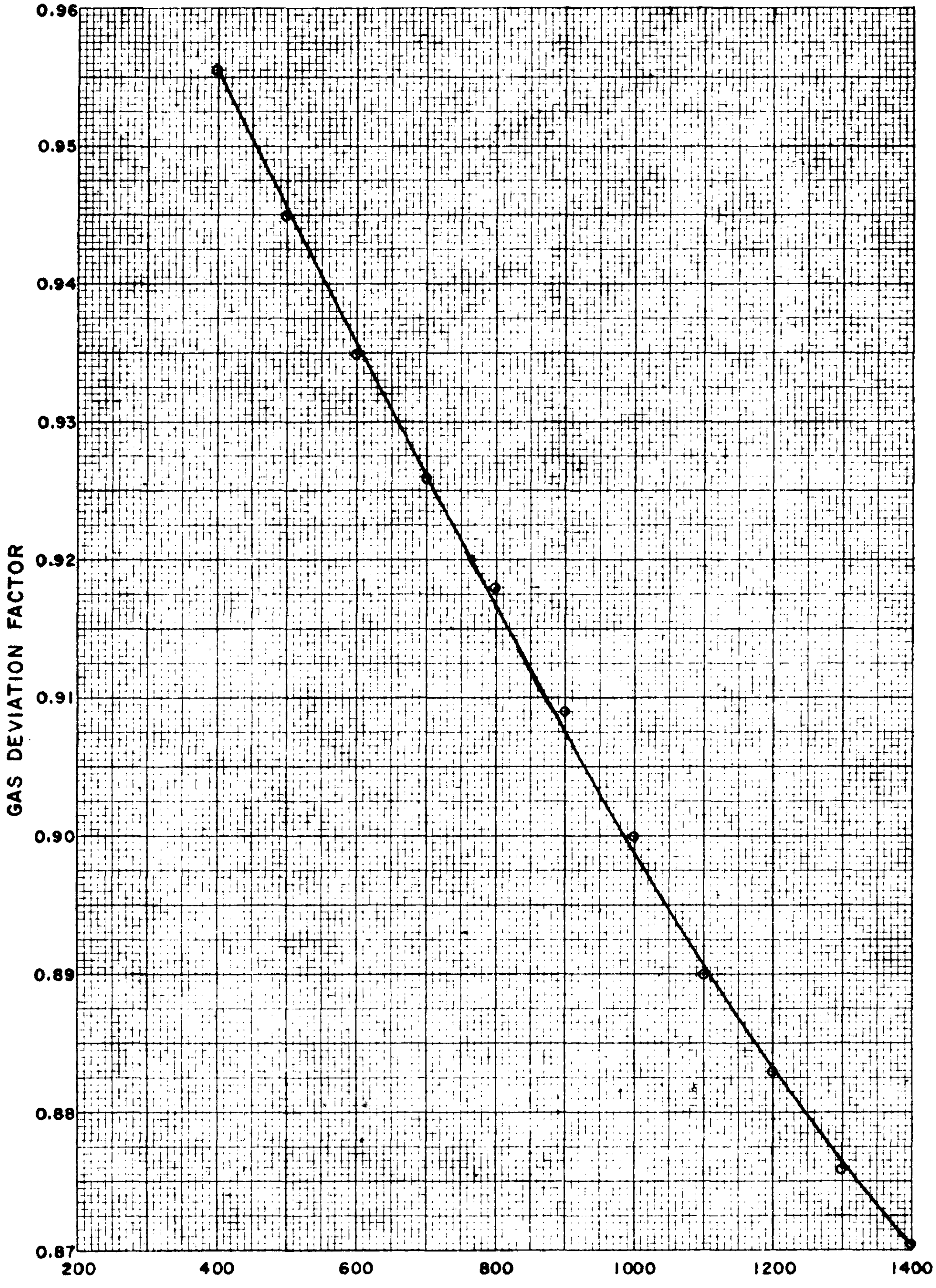


Figure 11: Oregon Basin Gas Deviation Factor

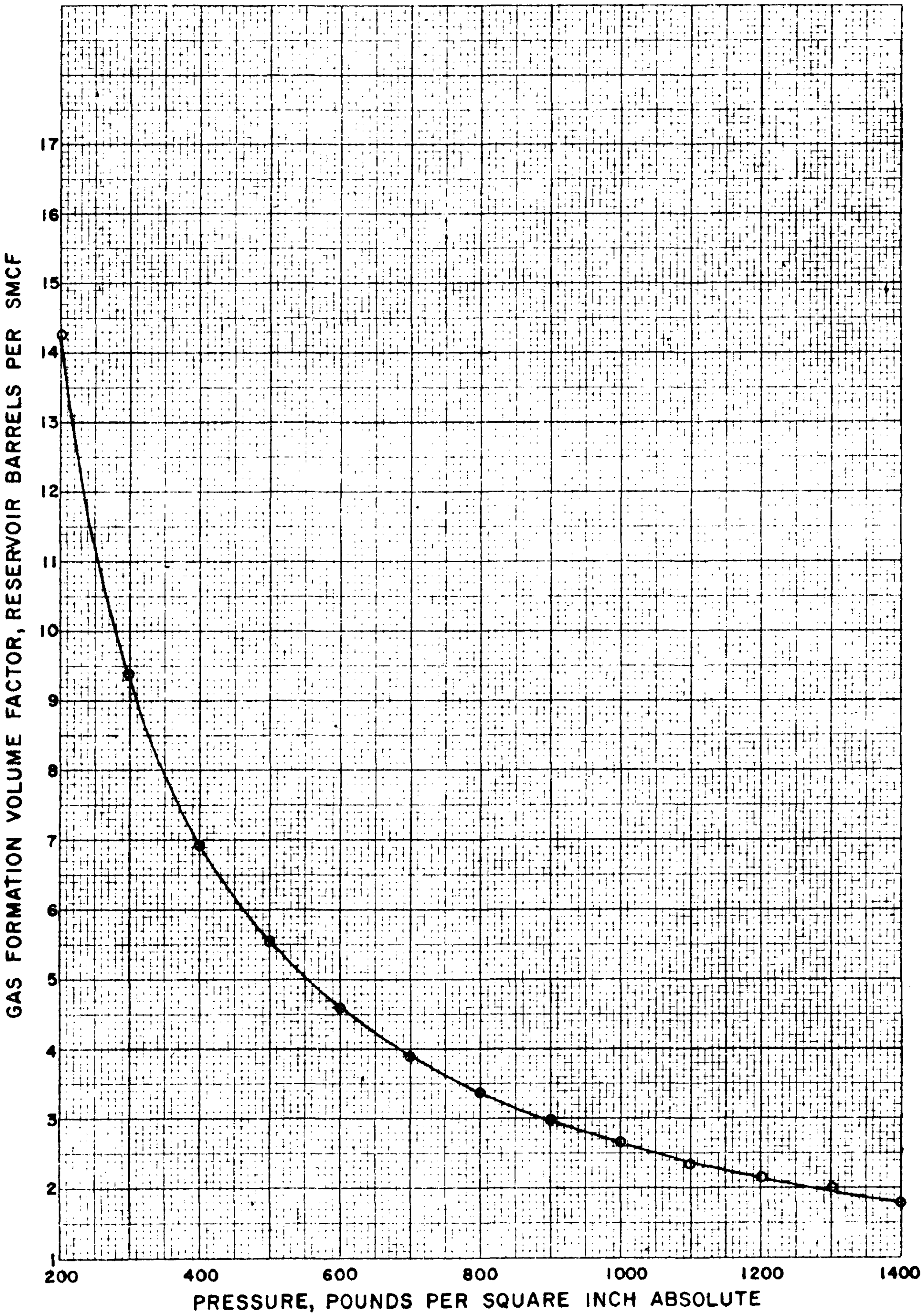


Figure 12: Oregon Basin Gas Pressure - Volume Relationship

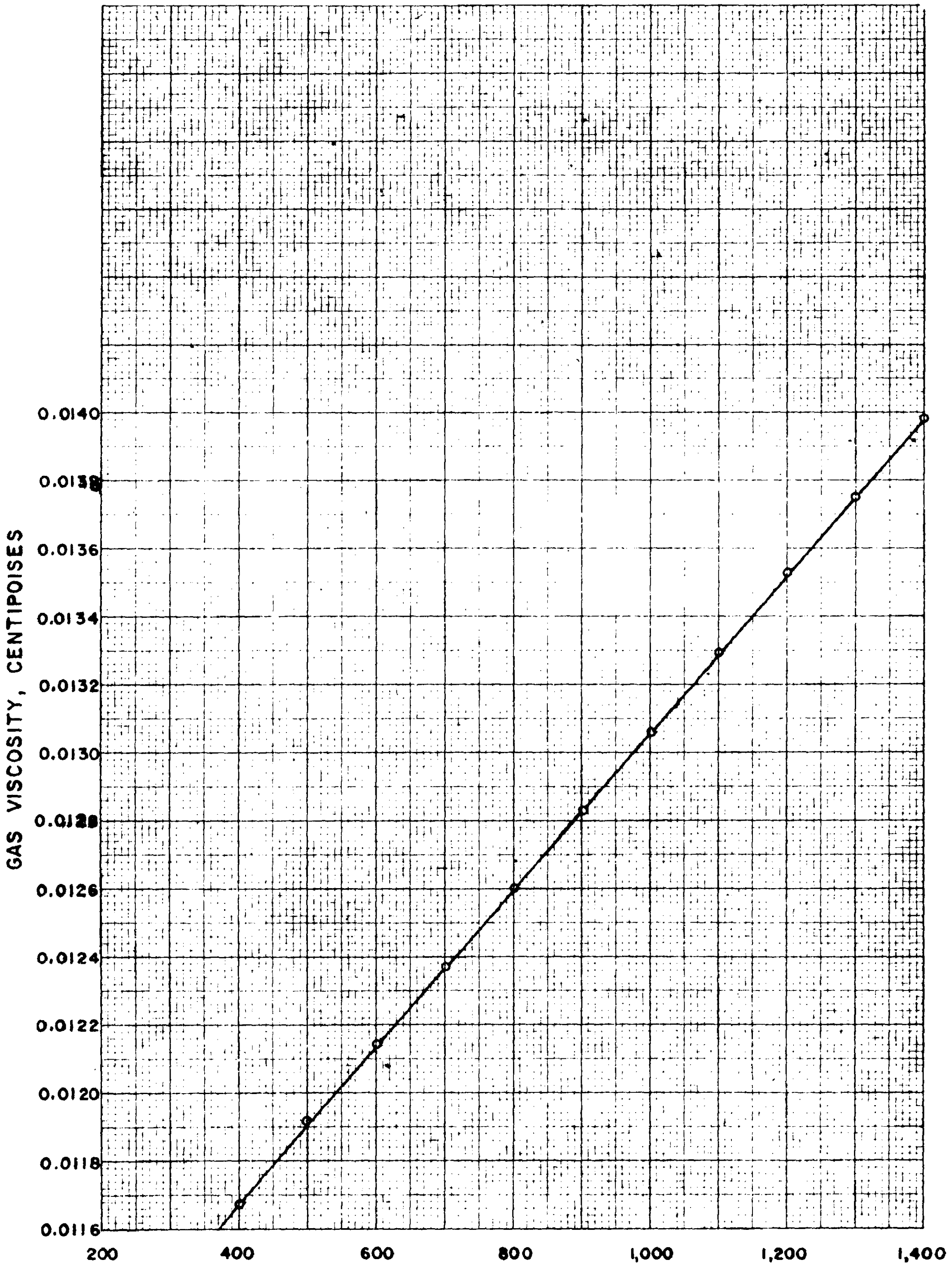


Figure 13: Oregon Basin Gas Pressure—Viscosity Relationship

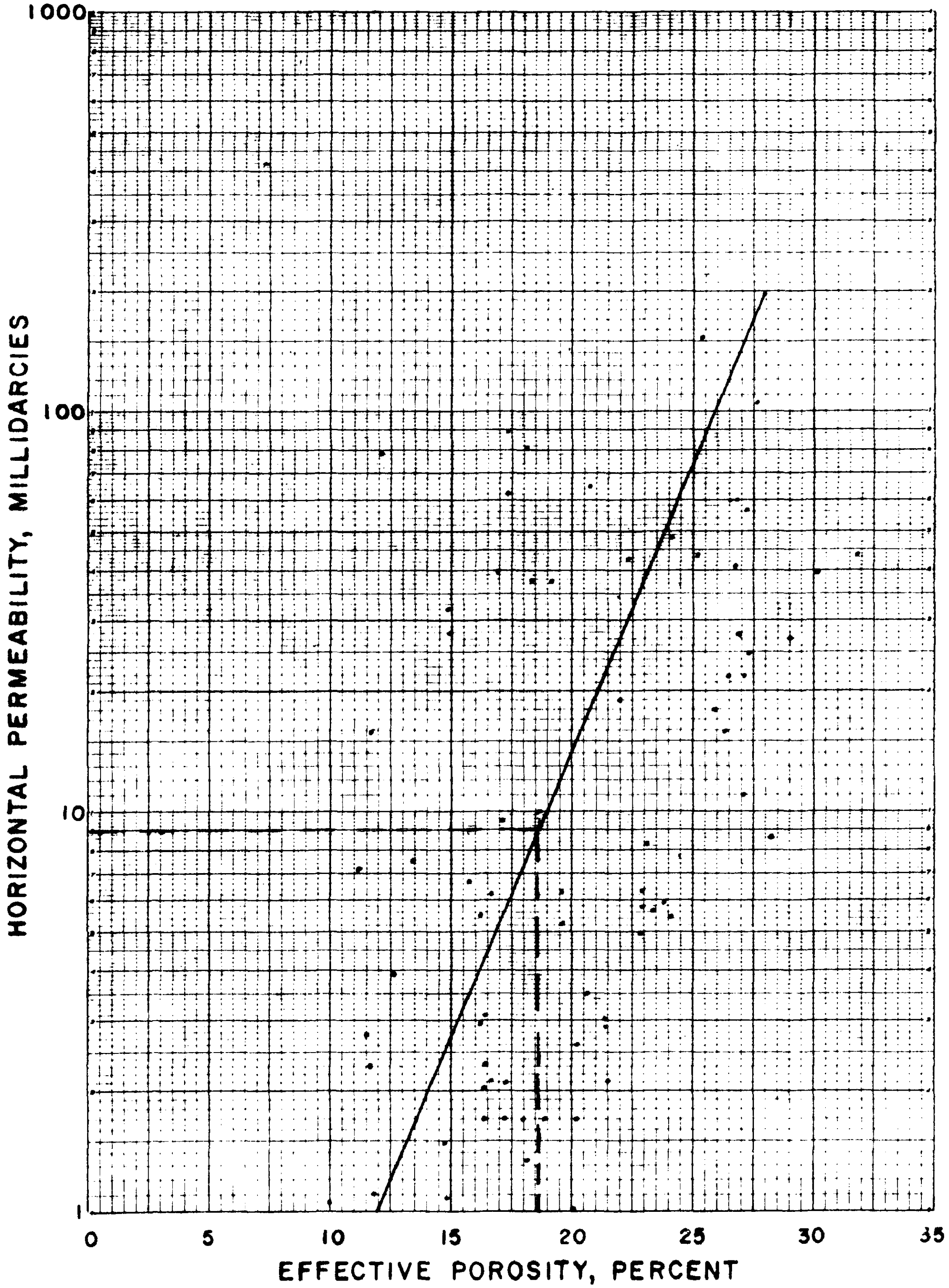


Figure 14: Grass Creek Phosphoria Horizontal Permeability — Porosity Correlation

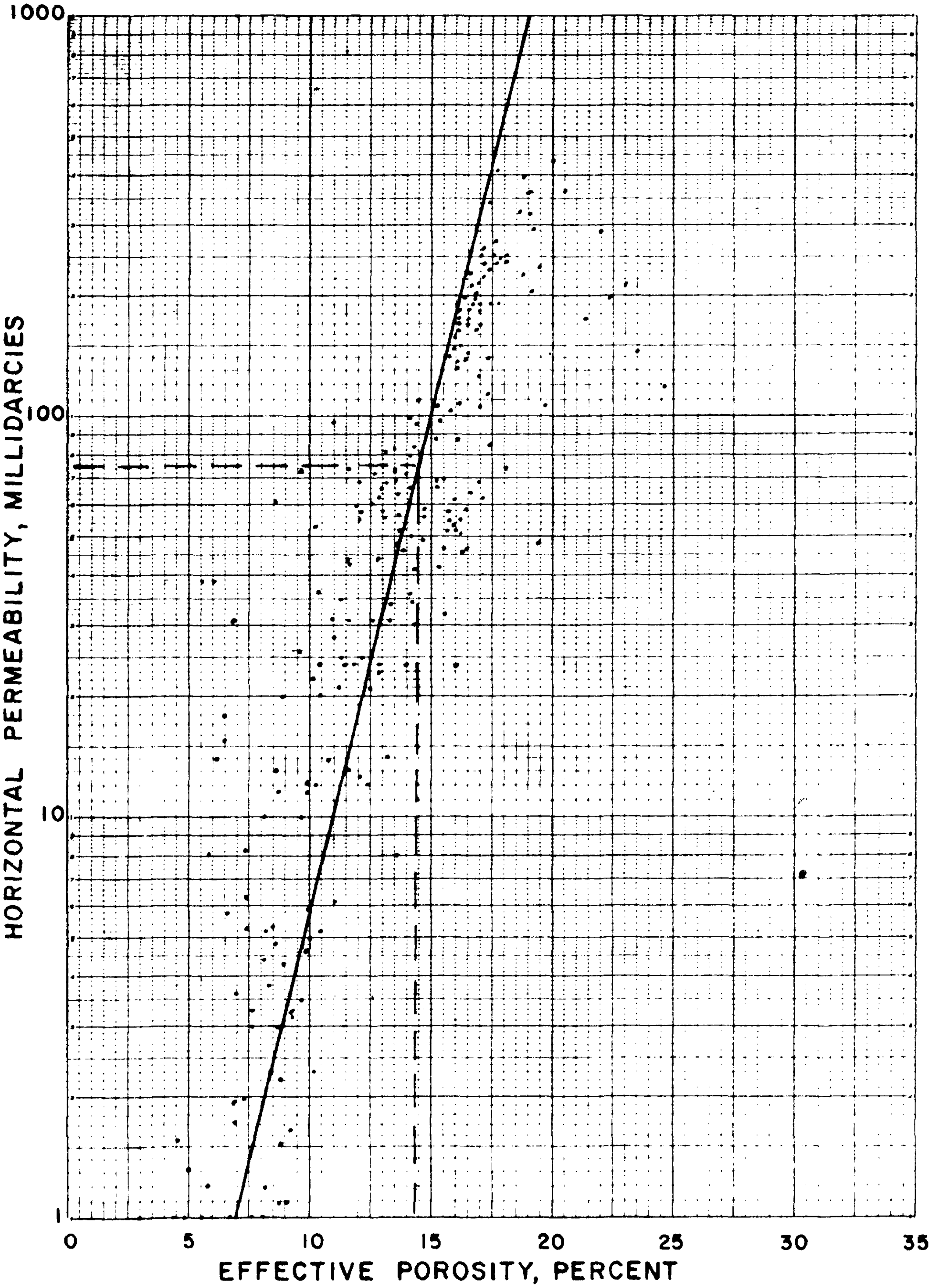


Figure 15: Grass Creek Tensleep Horizontal Permeability — Porosity Correlation

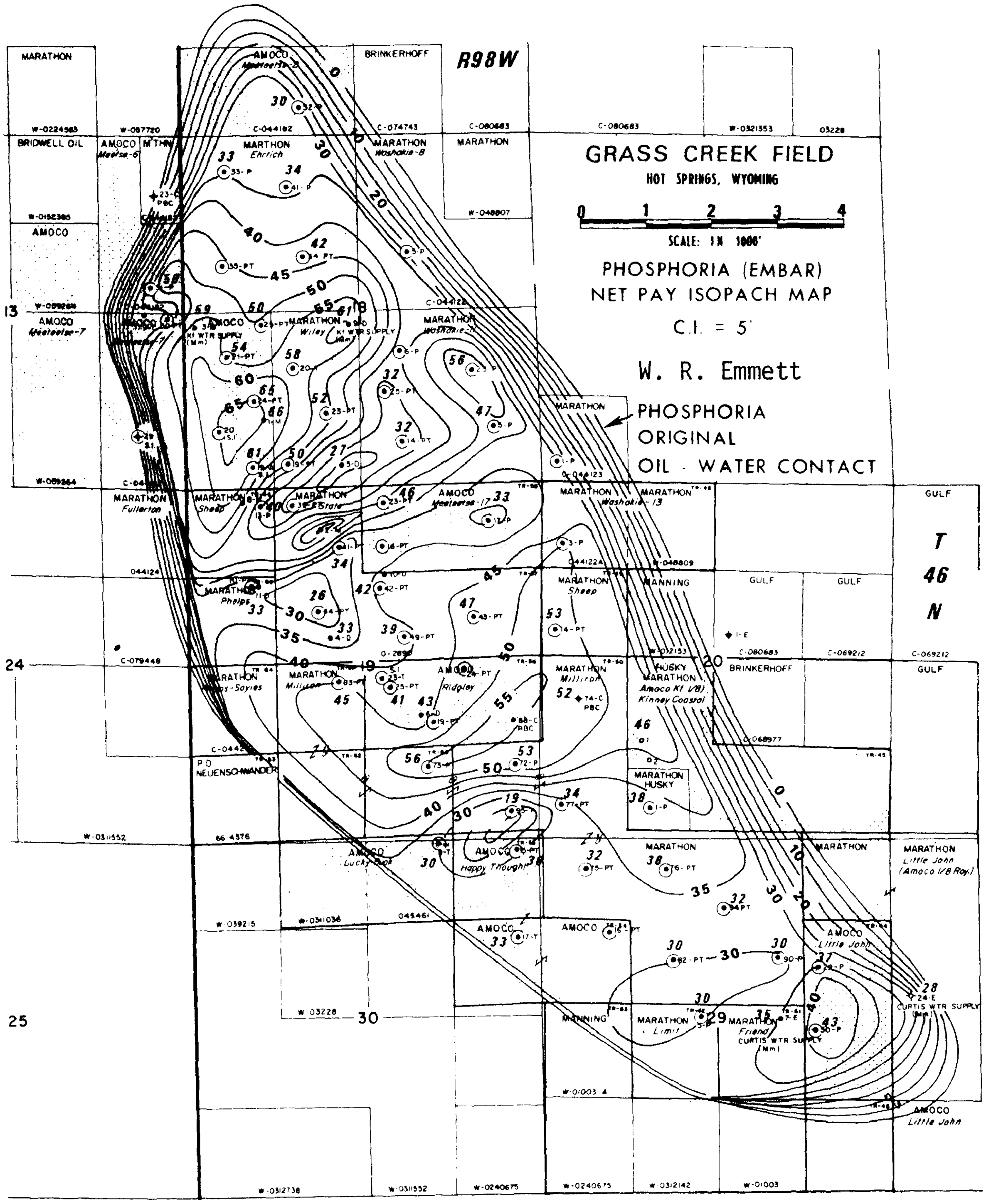


Figure 16: Grass Creek Phosphoria Effective Pay Isopach

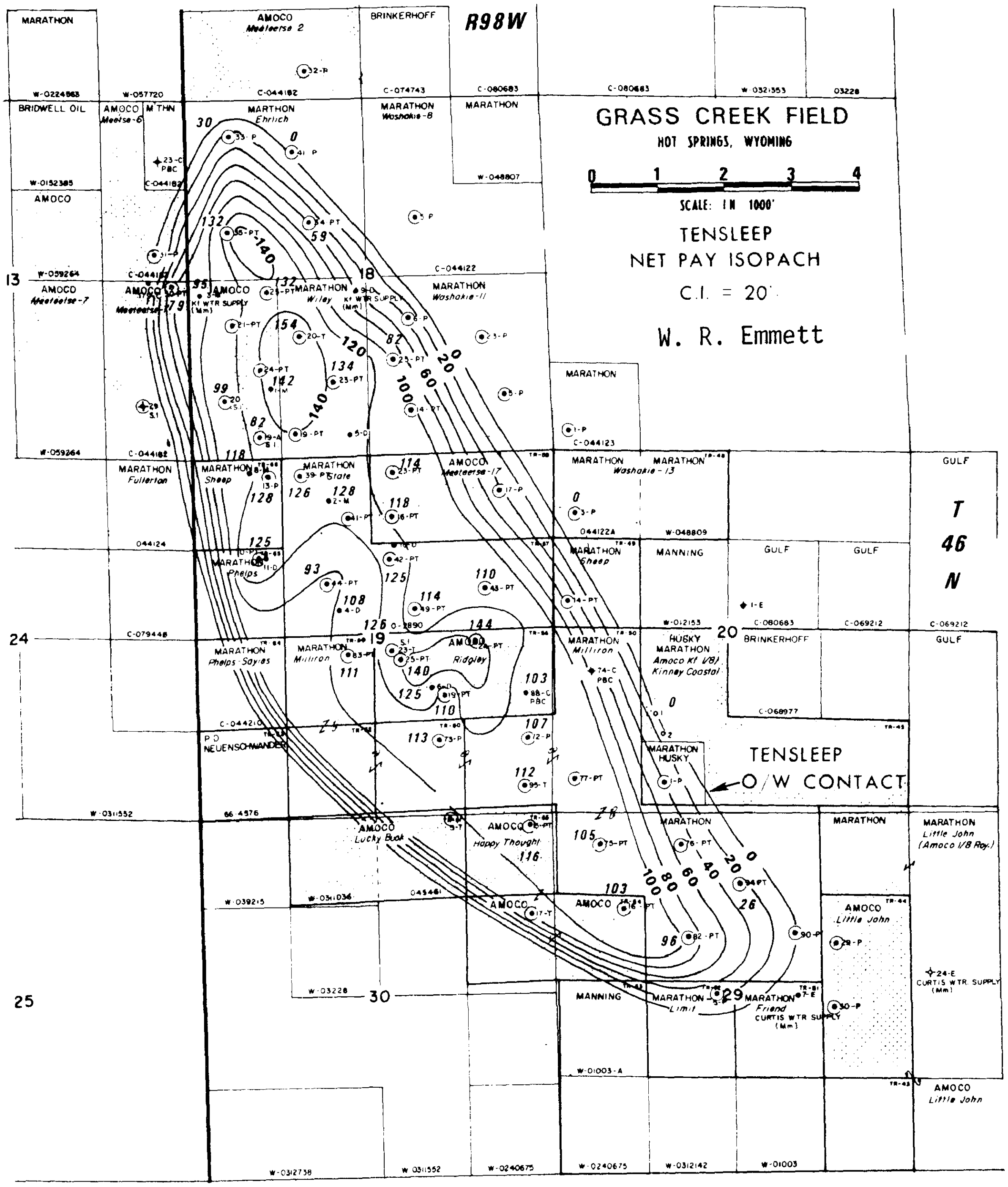


Figure 17: Grass Creek Tensleep Effective Pay Isopach

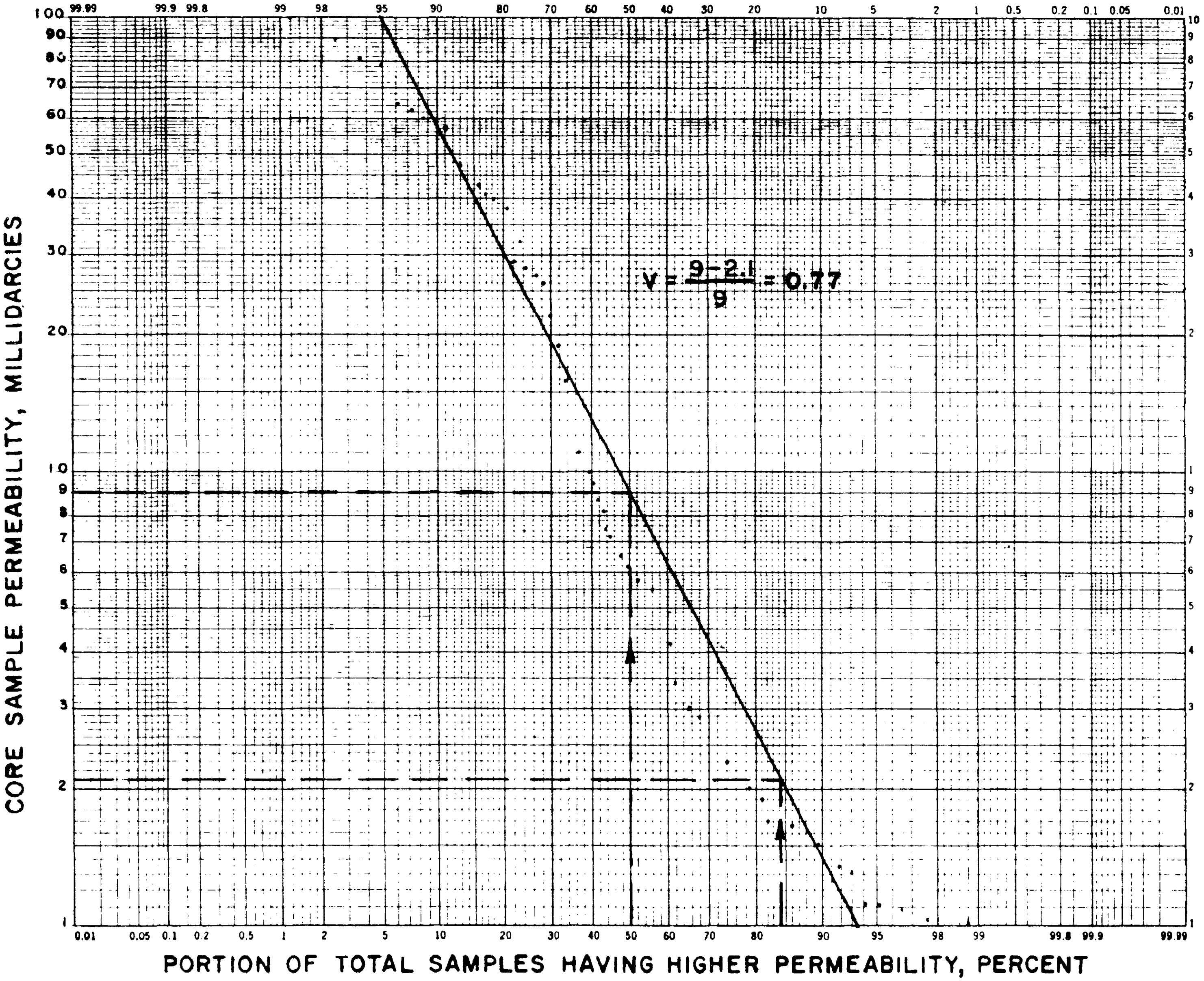


Figure 18: Grass Creek Phosphoria Permeability Variation

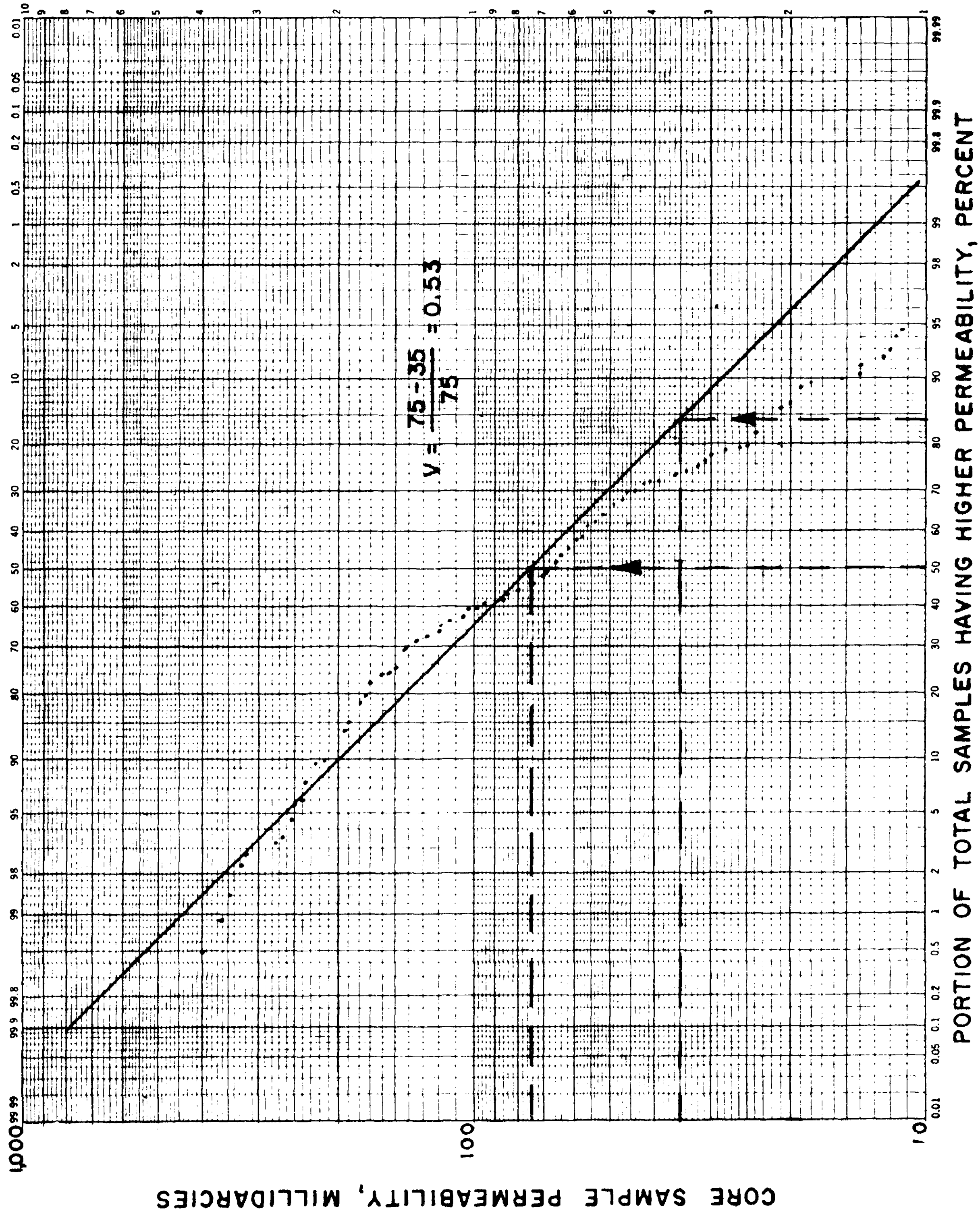


Figure 19: Grass Creek Tensleep Permeability Variation

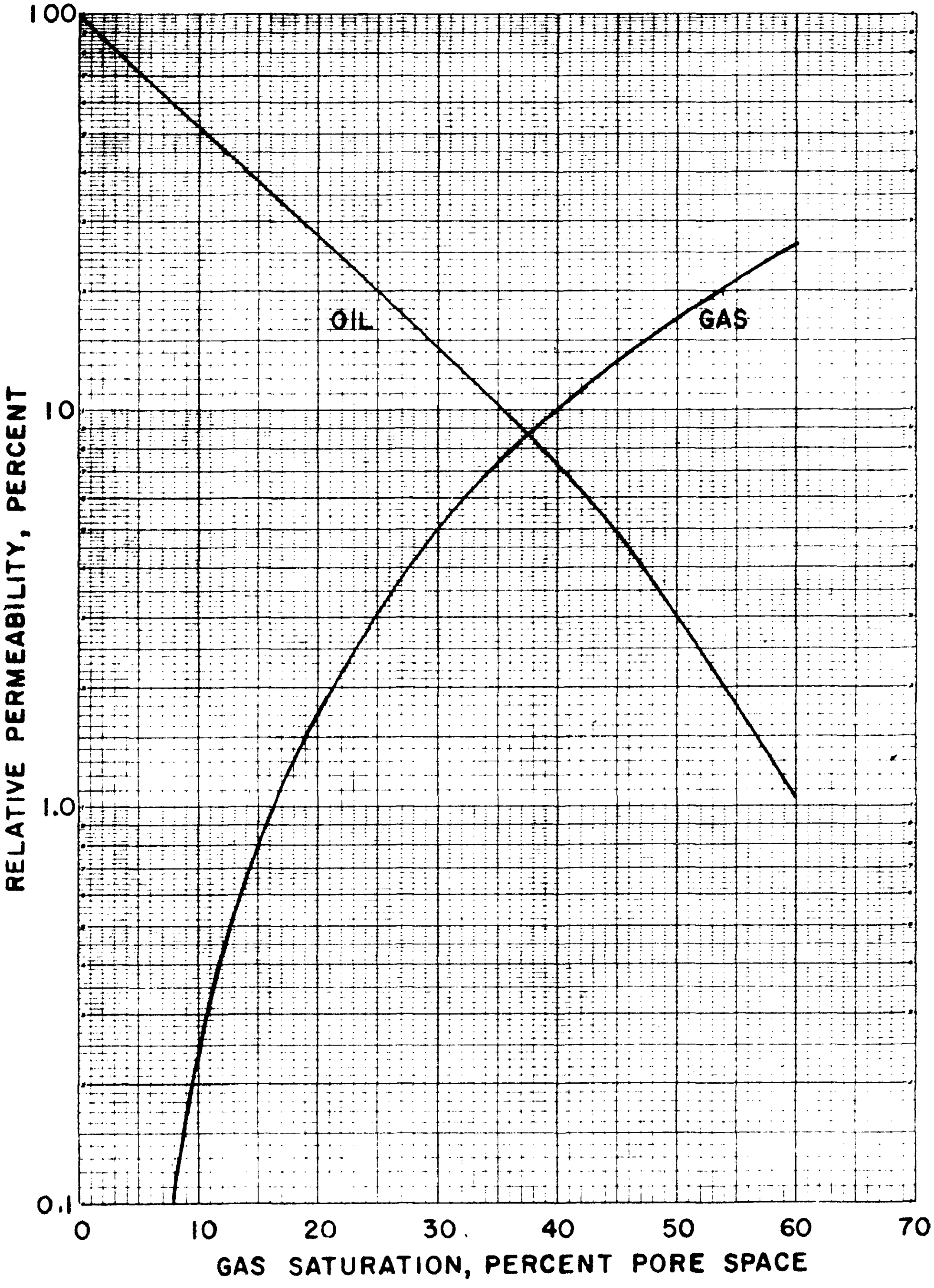


Figure 20: Grass Creek Tensleep Gas-Oil Relative Permeability

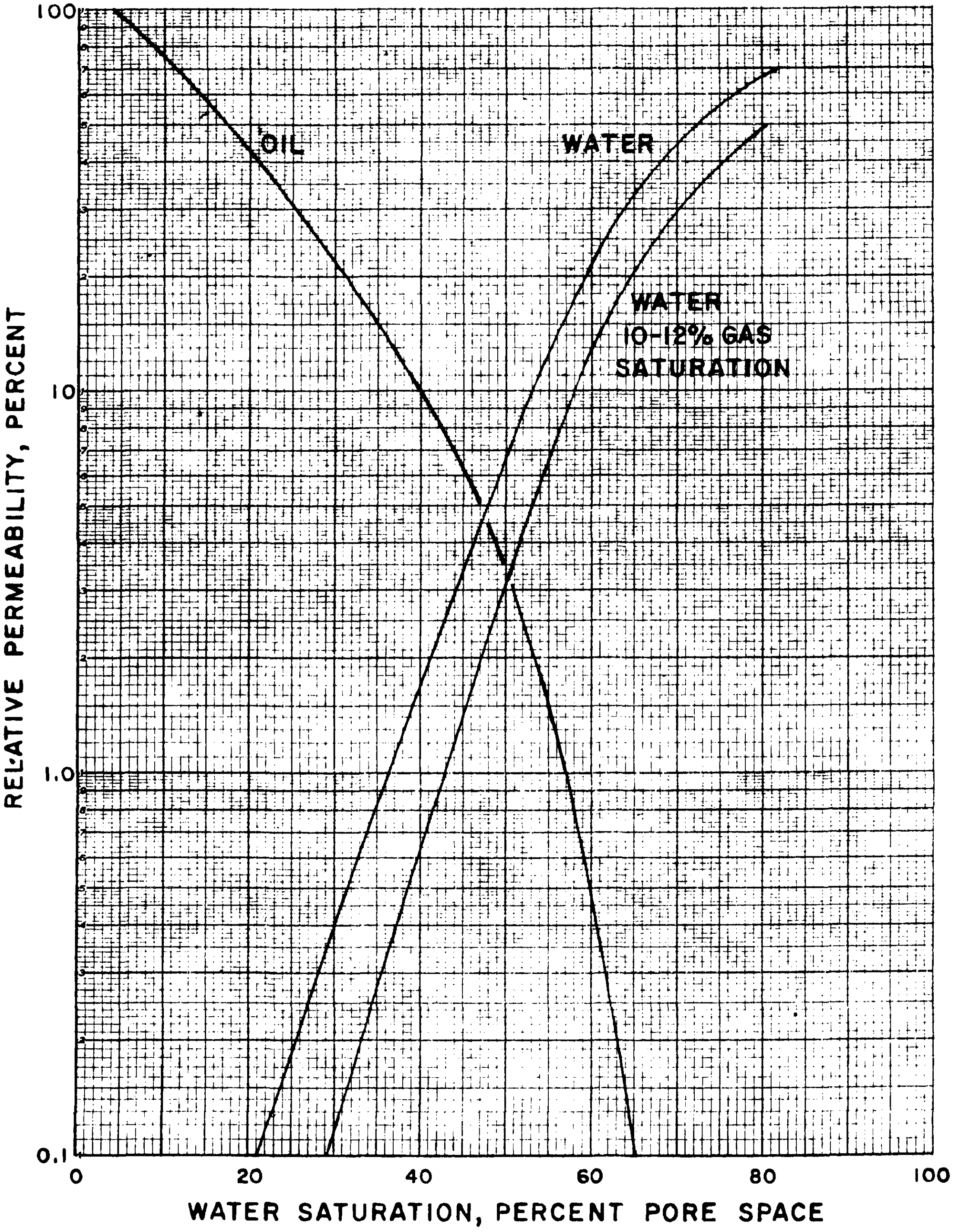


Figure 21: Grass Creek Tensleep Water-Oil Relative Permeability

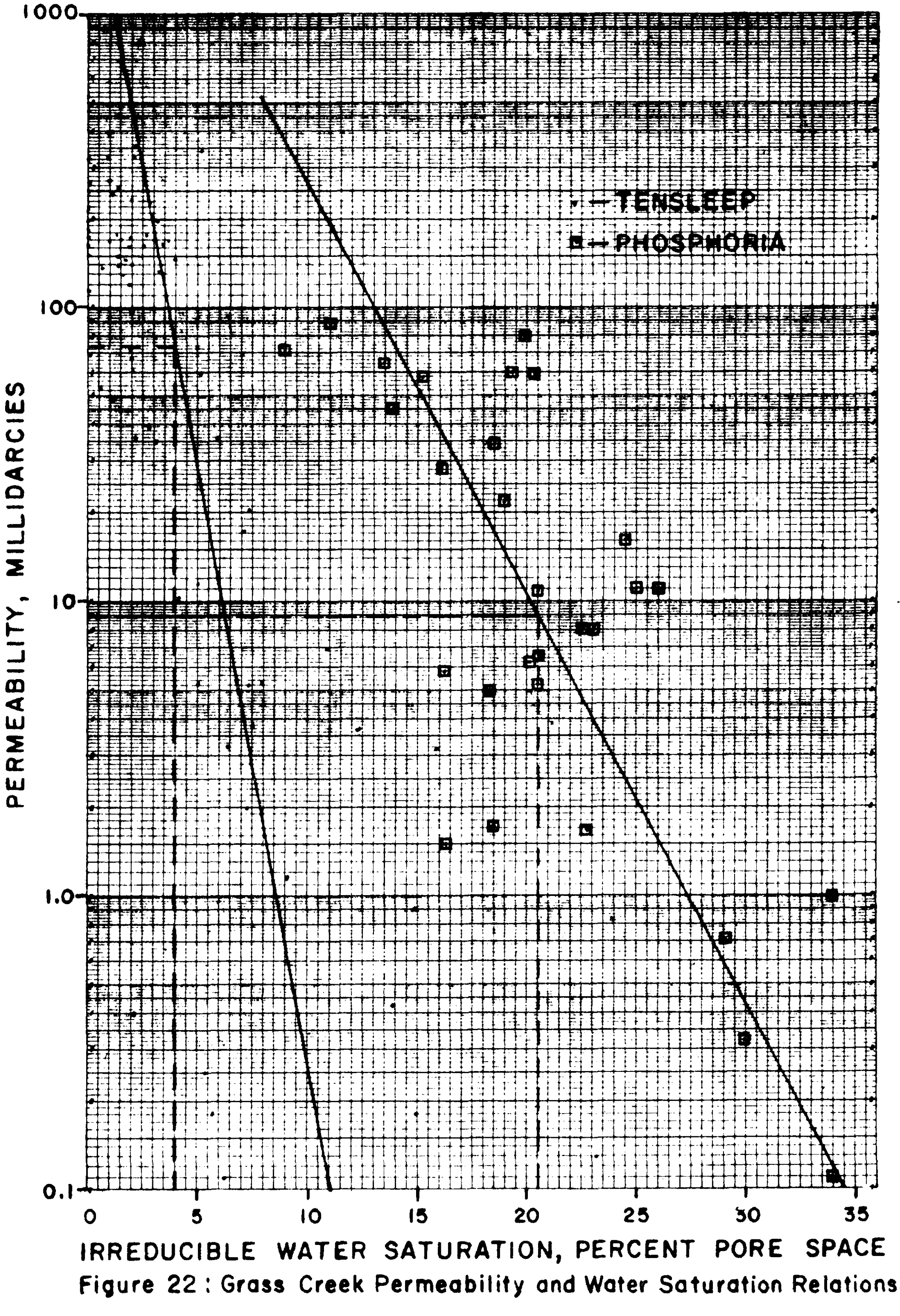


Figure 22 : Grass Creek Permeability and Water Saturation Relationship

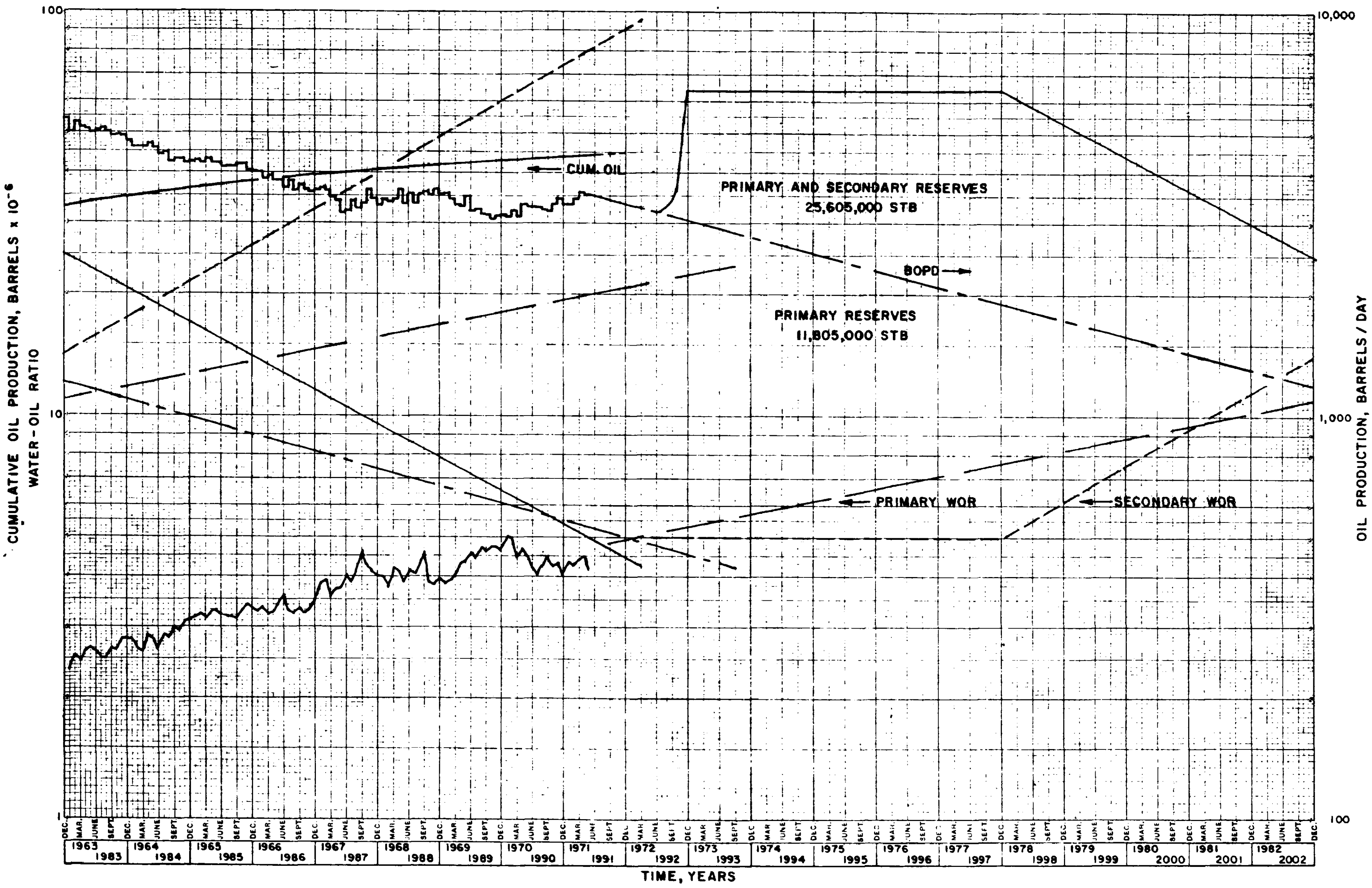


Figure 23: Grass Creek Phosphoria-Tensleep Production History And Forecast

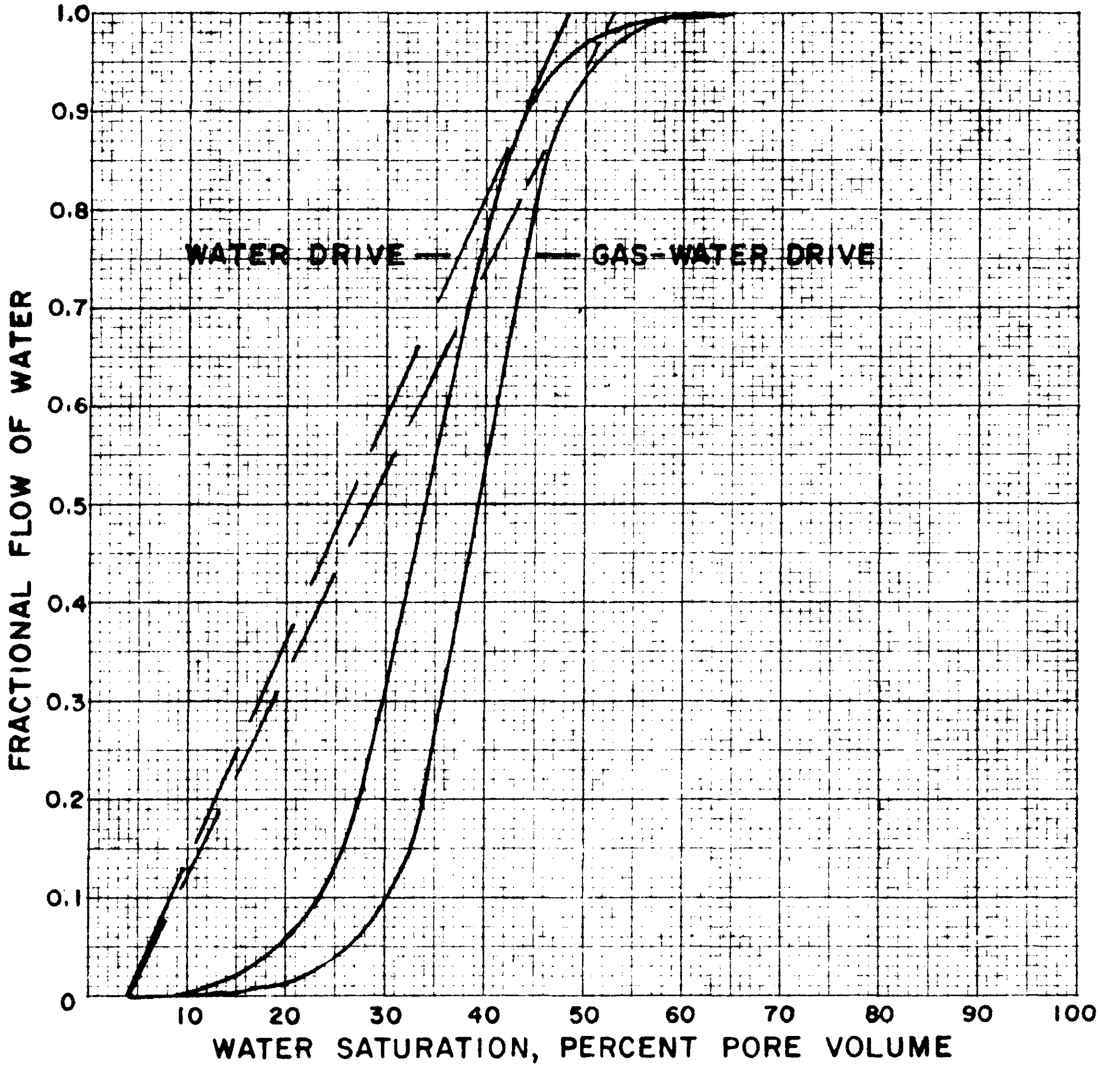


Figure 24: Grass Creek Tensleep Water Fractional Flow Relationship

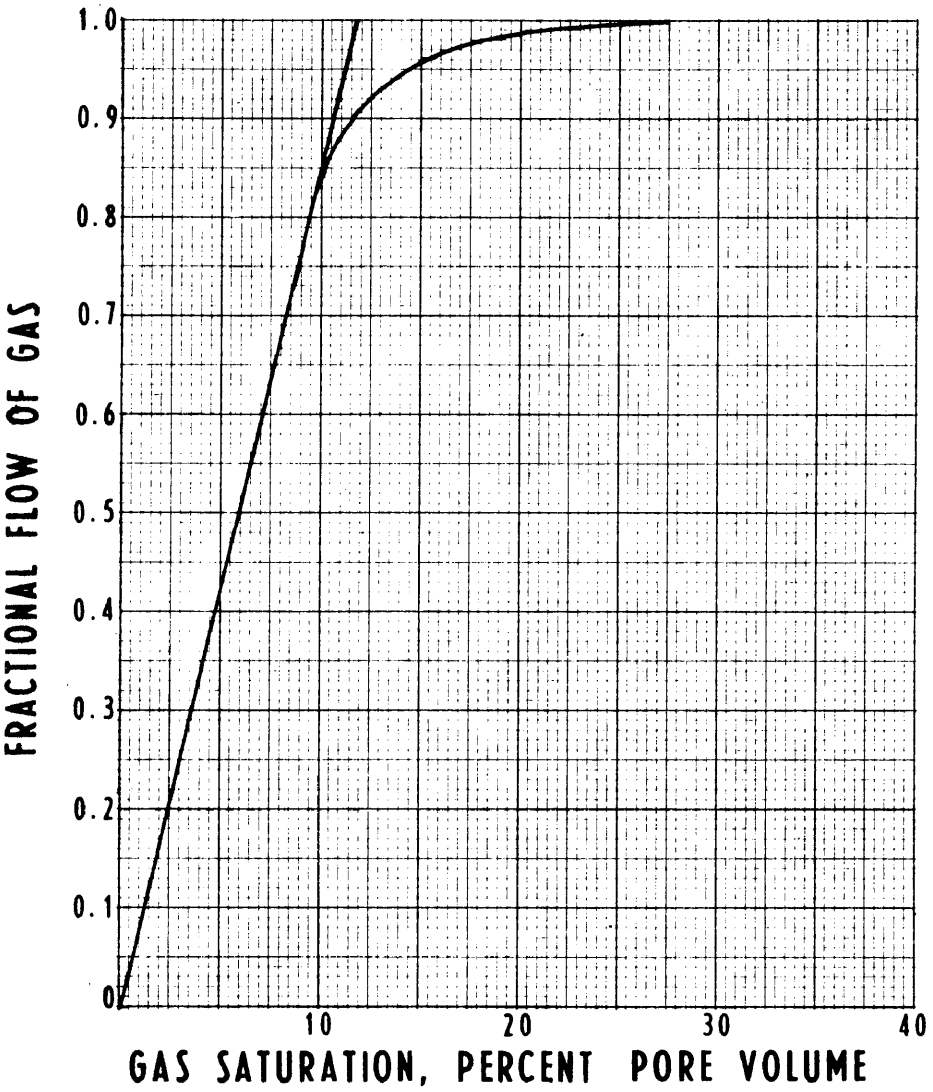


Figure 25: Grass Creek Tensleep Gas Fractional Flow Relationship

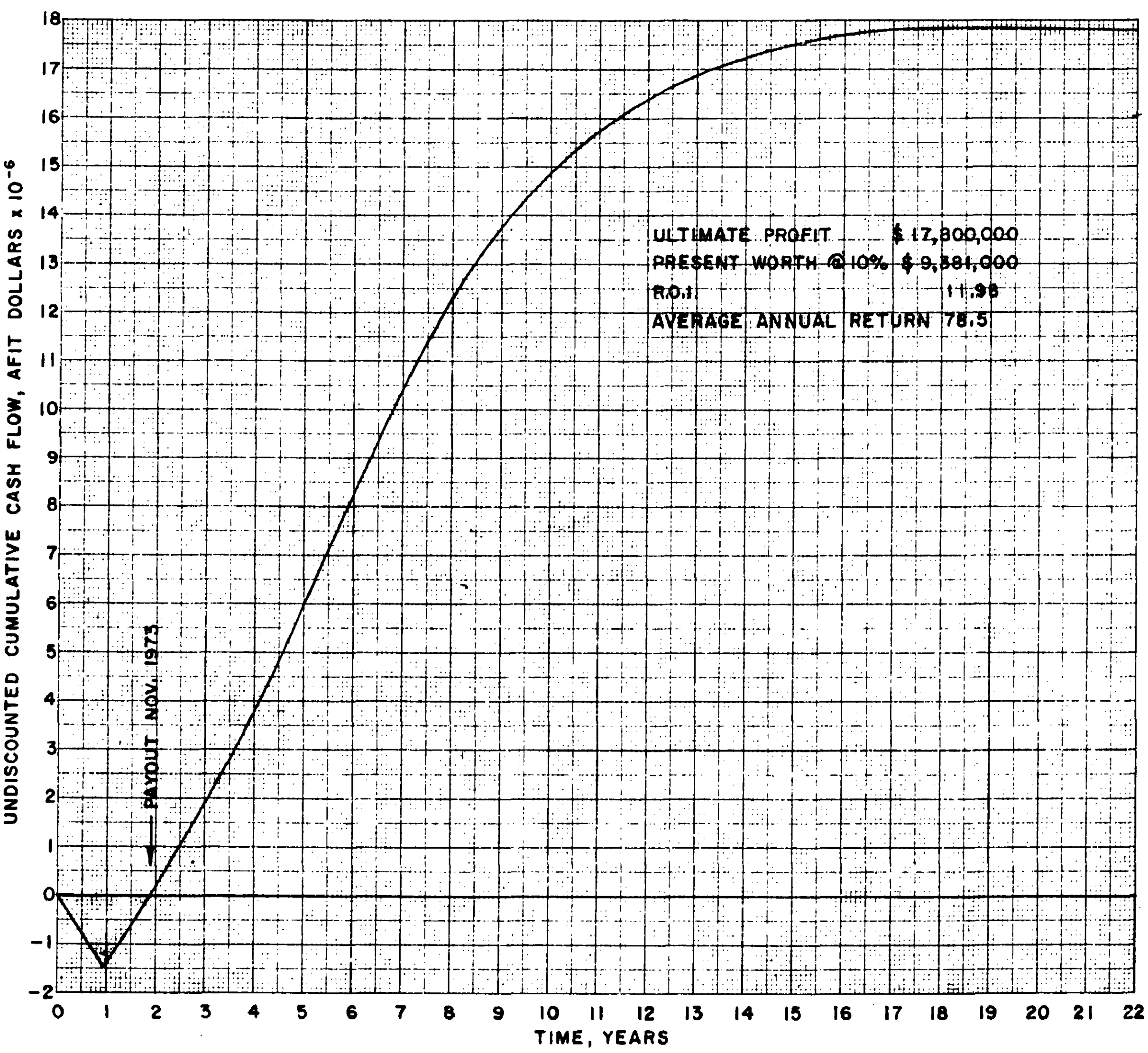


Figure 26: Incremental Cash Flow Of Secondary Recovery Operations