

SECONDARY RECOVERY  
OF OIL  
IN SOUTHEAST SUMATRA FIELD

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By

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A Thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science in Petroleum Engineering.


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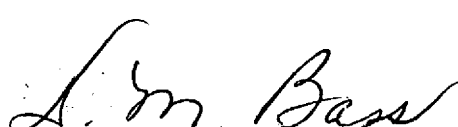
  
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ABSTRACT

A reservoir engineering study was made to determine the feasibility of waterflooding the Southeast Sumatra Field. A possibility of improving the waterflood by use of polymers in the injected water was also studied. The oil-in-place was calculated volumetrically and primary performance calculations were made from the field production data available. Calculations were made to determine additional oil recovery by waterflooding and polymerflooding.

Comparison of the waterflood and polymer-flood performance calculations indicated 802,000 STB of additional oil would be recovered by polymerflooding the reservoir. Although from the calculations it seems a waterflood will be economical, polymerflooding of the Southeast Sumatra Field is recommended.

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INTRODUCTION

A reservoir engineering study was made to determine the feasibility of waterflooding and polymerflooding the Tyler Sand pay in the Southeast Sumatra Field. Data used for this study were obtained from fluid analyses and special core analyses, well logs from each well, production information from the field, and data from surrounding fields producing from the Tyler Sand. No pressure history for the field was available except for an initial pressure.

Isopach maps for the Tyler N and P sands that are present in the Southeast Sumatra Field were prepared from the individual logs and the oil volume was calculated volumetrically from the reservoir volume and other reservoir parameters such as oil saturation and porosity. Primary recovery was obtained from production data as the field is practically depleted. Secondary oil recovery by waterflooding was obtained by multiplying a volumetric reservoir recovery efficiency by the oil

in place. The volumetric efficiency considered a vertical sweep efficiency and an areal sweep efficiency.

Oil recovery by polymerflooding was obtained by assuming that the vertical efficiency of the reservoir would be improved by polymers injection.

Cash flows were calculated for the waterflood and for the polymerflood performance. Undiscounted and discounted profit and payout were obtained by comparing the two cash flows and considering investments for the waterflood and the polymerflood.

## GEOLOGY AND HISTORY

The Southeast Sumatra Field is located in Township 11 North, Range 32 East, Rosebud County, Montana, some ten miles north of Melstone, Montana. The following is a discussion of the geology and history of the Southeast Sumatra Field:

### Geology of Field

The Southeast Sumatra Field is located within the Central Montana Uplift in Township 11 North, Range 32 East, Rosebud County, Montana. The structure is an asymmetrical anticlinal nose for secondary recovery purposes. The field has been divided into four units, namely: West Sumatra, Central Sumatra, Northeast Sumatra and Southeast Sumatra (Fig. 1). The Southeast Sumatra Unit comprises the eastern portion of the Sumatra Field. Its relation with the main part of the field is shown in Figure 1. The structure of the Tyler formation in and near the Unit is shown in Figure 2.

A typical stratigraphic column is shown in Figure 3. The Sumatra Field reservoir consists of seven sand lenses which are designated m, n, o, p, r, s, and t. These sands are shown in Figure 4. Oil production has been found in the Piper Limestone, Upper Tyler Sand, and Amsden Dolomite. However, this report is confined to the Lower Tyler Sands. The sands are described as being fine- to medium-grained, well-sorted, rounded to subangular quartz sandstone. The lenticular Lower Tyler Sands that produce in the Southeast Sumatra Unit are the N sand and the P sand. Isopach maps for these sands are shown in Figures 5 and 6. The P sand extends the length of the Unit, whereas the N sand is confined to the Northwestern part of the unit. Both sands continue beyond the Unit boundary. The P sand lens in Section 24 overlaps the N sand but is not connected with it. Figure 7 is a cross section showing the continuity of these two sand lenses. It is believed that these sands are of Lower Pennsylvanian Age and were deposited in stream channels cut into the underlying Heath (Mississippian) formation.

#### Development History of the Field

The discovery well for the Sumatra Field was Horgan No. 1 in Section 13, Township 11 North, Range 32 East. This well was completed in September, 1951, pumping 76 barrels oil per day. Grebe No. 2 was drilled in July, 1952, and this well kicked off active development until April, 1955. The first well drilled in Southeast Sumatra was the Grebe No. 1 in Section 24, on September 30, 1957, and had an initial production

of 146 BOPD. Development of the field was continued between that time and late 1961. Twenty-nine wells were drilled during this period of time. Five wells were found to be dry (no pay).

The rest of the wells are producing or have produced at one time from the Tyler Sand except the O'Neill Ottman No. 7 (Section 23), which is a temporarily abandoned well that produced from the Heath formation at one time. Location of all oil and gas wells, dry holes, and the names of owners of interest in the oil and gas within Southeast Sumatra are shown in Figure 8.

The best well as far as initial production is concerned was Harris No. 5, in Section 24. This well was completed in February, 1958, and had an initial production of 355 BOPD. The poorest producer was Grebe No. 6, in Section 24, completed in June, 1961, with an initial production of 30 BOPD. At the time of the highest well density in the field, the peak field production was 40,000 barrels oil per month in October, 1962, and the lowest was 3,689 barrels oil per month in July, 1969, six months before water injection started in the field. (Despite the fact that water injection started January 1, 1970, no waterflood feasibility study has been made so far.) Water production has been insignificant; therefore, it has not been recorded except when there was a trace. Three wells were drilled for injection purposes in the Northern edge of the field in September, 1969, i.e., WIW No. 1, WIW No. 2, and WIW No. 3, all of them located in Section 24, on April 16, 1969. Three ex-producing wells, Cardinal No. 3, in Section 36;

Ottman No. 2, in Section 24; and Harris No. 7, in Section 24, were converted into injection on February 12, 1970. Currently in the field there are 18 producing wells, 6 injection wells, and 1 water-supply well.

RESERVOIR PARAMETERS

The following is a discussion of the determination of effective pay thickness, porosity, permeability and water saturation for Southeast Sumatra Field:

Effective Pay Thickness

Net pay sand was determined by microlog separation in conjunction with electric logs, drill-stem tests, cores, and production data. The field average net-pay thickness was found to be 21.1 feet. The maximum pay section encountered in any well was 70 feet. The top and the bottom of the pay were obtained by using the SP and laterolog as shown in Figure 7.

Net pay in each well was plotted and an isopach map for the N sand and another for the P sand were drawn (as shown in Figures 5 and 6). The total productive acreage for the Southeast Sumatra Field was found to be 1,360 acres. Reservoir acre-feet were determined by the use of a planimeter and checked by the reading of a 2½ acre grid system. The

reservoir volume calculated from the isopach maps were 5,393 acre-feet and 23,274 acre-feet for the N and the P sands, respectively, giving a total volume of 28,667 acre-feet for the whole field.

### Porosity

Because there was core data from only two wells in the Southeast Sumatra Field, it was thought at first it would be better to obtain the porosity from a statistical analysis of the core samples available from cored wells, in Southeast Sumatra and Central Sumatra Fields, producing from the N sand or the P sand. Results of this statistical analysis were not found to be representative for our unit; therefore, the porosity of the main pay was obtained from a statistical analysis of core samples from wells Harris No. 2 and No. 4, in Section 24 of Southeast Sumatra. Results are as follows:

Arithmetic average porosity	12.3
Arithmetic mean porosity	12.4
Median porosity	11.5
Standard deviation	2.7

Arithmetic mean porosity was used in this study. Electric logs were used to verify the porosity obtained from cores.

### Permeability

The horizontal permeability of the main pay was also determined by statistical analysis of all the core samples from wells Harris No. 2 and No. 4. Results of this statistical analysis were found to be as follows:

Arithmetic average horizontal permeability	26.4 md.
Geometric mean horizontal permeability	15.8 md.
Vertical permeability variation	0.73

Geometric mean permeability was used in this study.

#### Water Saturation

A plot of permeability versus connate water was drawn (Figure 9) from selected core samples from various parts of the reservoir. These determinations were made in connection with water flood susceptibility tests which were run for the Sumatra Field. A connate water saturation value of 36 taken from Figure 9 at the geometric mean permeability of 15.8 was used in this study. Water saturation calculations from logs were found to be unrealistic.

RESERVOIR FLUID STUDIES

Two bottom hole fluid samples have been analyzed for PVT data; Grebe No. 5, Section 11, was sampled May 27, 1954. The results of these analyses are presented in Table 1. Figure 10, which is a composite of both samples, shows the data used in this study. These data were used in this study because no fluid samples from wells in Southeast Sumatra were available; however, it is known that the initial reservoir pressure in Southeast Sumatra was about 50 Psi above bubble-point pressure (790). The differences in PVT data as shown in Table 1 are believed to be due to the fact that the sample from Montana State No. 5 was taken at a later date and lower reservoir pressure than the sample from Grebe No. 5. Some water was present in the State No. 5 sample. For these reasons in constructing the composite curve, the Grebe No. 5 sample was favored by a ratio of 75:25. In referring to Figure 10, it is noted that the saturation pressure is 790 Psia; therefore, the crude existed in an undersaturated condition at the original field reservoir pressure of 1880 Psia. Presented in Table 2 is a

partial crude oil analysis showing the oil viscosity at various temperatures. A complete gas analysis has not been obtained, but the specific gravity has been measured as 0.950 at 165°F, reservoir temperature.

Gas viscosity at various pressures was obtained for a 0.950 gravity gas. The gas compressibility factor was calculated for various pressures by the pseudo-critical temperature and pressure method. A list of reservoir fluid characteristics adjusted for the conditions at the start of the development in Southeast Sumatra is given in Table 3.

DETERMINATION OF OIL-IN-PLACE

The oil-in-place was calculated volumetrically with the known reservoir parameters. The formula used for the calculation was the following:

$$N = 7758 \phi A h (1 - S_{wi}) / B_o$$

where:

- $\phi$  = average arithmetic mean porosity, fractional
- A = surface area, acres
- h = effective pay thickness, feet
- $S_{wi}$  = average initial water saturation, fractional
- $B_o$  = oil formation volume factor, res bbl/STB

Based on the reservoir volume of 28,667 acre-feet the oil in place was found to be 15,215,500 STB or 530.8 STB per acre-feet. Original gas in place was 3,021 MMCF. This figure was found by multiplying the original oil in place by the initial gas solubility (198.5 CF/Bbl). Material balance could not be used for the calculation of oil in place because of the absence of pressure history in Southeast Sumatra.

PRIMARY PERFORMANCE

The Sumatra Field was initially an undersaturated reservoir with solution gas as the primary recovery energy below the bubble-point pressure. Fluid and rock expansion was the primary reservoir mechanism above the bubble point.

As mentioned earlier, the southeast portion of the Sumatra field was the last to be developed. Initial pressure in this section was about the bubble-point pressure (790 psi); therefore, it is believed that no oil recovery due to fluid and rock expansion alone occurred in Southeast Sumatra as the reservoir was initially saturated. Production since the beginning of the development of the field (1957) up to January 1, 1970, has been due to solution gas drive.

The field was practically primarily depleted when water injection started (January, 1970) as the reservoir pressure was about 50 psia and 2,650,000 STB out of a primary recovery estimate of 2,670,000 (at economic limit of 3,800 barrels of oil per month) had been produced.

For the confirmation of the estimated primary recovery, a field decline curve of the oil production rate of the field was plotted against time on semilog paper (Figure 11). Extrapolation of this decline curve indicates primary production to be 2,670,000 STBO at the field economic limit. Individual well-decline curves were not drawn as the production is measured by leases because of commingled production.

No water influx was assumed as wells in the unit do not produce water and the field production decline curve is a typical solution gas drive curve. No pressures are available for material balances to confirm the assumption of no water influx.

## SECONDARY PERFORMANCE

Because of the low primary recovery and relatively good results of secondary projects in the other sections of the Sumatra Field and neighboring areas, a secondary recovery project was thought to be worthwhile in Southeast Sumatra. Gas flooding and miscible flooding were discarded as secondary recovery methods because there is not a cheap supply of either gas or LPG nearby. Water injection is the only applicable method of secondary recovery in this field. The following is a discussion of how the secondary recovery performance calculations were made.

### Laboratory Waterflood Tests

Water susceptibility tests for the Sumatra Field were run on six samples by Core Laboratories, Incorporated. Results indicated early water breakthrough with a relatively high water cut throughout the flood. Although a green clay material was observed in two samples, which caused high water saturations, no swelling or detrimental effect

was evident from water flooding. Based on the laboratory's analysis of eight samples, the average residual oil saturation applicable for the entire Sumatra Field was determined as 22.2 per cent of the pore space.

### Sweep Efficiency

The oil recovery by waterflooding the Southeast Sumatra Field was determined by obtaining the product of applicable sweep efficiencies and the oil-in-place. The sweep efficiencies were obtained as follows:

1. The vertical sweep efficiency was obtained with the use of the Dykstra-Parson's (1950, p. 160-175) method for reservoirs with permeability variation.
2. The areal sweep efficiency was obtained by using a correlation between line drive flood pattern and areal sweep efficiency given by Muskat (1934, p. 62). This value was corrected for the Southeast Sumatra Field with areal sweep efficiencies obtained from neighboring fields. The displacement efficiency could not be calculated because of the absence of water-oil relative permeability data. For practical purposes a displacement efficiency of 1 was assumed in this report.

Oil recovery from waterflooding was obtained with the use of the sweep efficiencies in the following equation:

$$N_s = N E_v E_a$$

where:

- N = oil-in-place, barrels  
E<sub>v</sub> = vertical sweep efficiency, fractional  
E<sub>a</sub> = areal sweep efficiency, fractional

A producing water-oil ratio of 25:1 was used as the limiting WOR for determining the sweep efficiencies, because it is believed on the basis of experience in this formation that very little oil is produced at a higher water-oil ratio than the one considered in this study.

### Vertical Sweep Efficiency

Because all the reservoir is not contacted by the injected water, the flood efficiency is reduced by a vertical sweep efficiency which considers permeability variations in the reservoir rock (the more adverse permeability variation, the poorer the flood). For the determination of the vertical sweep efficiency, the horizontal permeability variation, the mobility ratio between the displacing and displaced fluids, and the limiting water oil ratio must be known. Fifty-eight feet of core data from the wells Harris No. 2 and Harris No. 4, in Section 24 of Southeast Sumatra were used to calculate the vertical permeability variation. Core data from wells located in neighboring units were not used as permeability values in those wells looked extremely high and differed too much from those in Southeast Sumatra. The equation used to calculate the mobility ratio is as follows:

$$M = \frac{K_{rw} \mu_o}{K_{ro} \mu_w}$$

where:

- $K_{rw}$  = relative permeability to water behind the flood front
- $K_{ro}$  = relative permeability to oil at the initial water saturation
- $\mu_w$  = viscosity of water, centipoises
- $\mu_o$  = viscosity of oil, centipoises

Values of the relative permeabilities were obtained from results of waterflood susceptibilities tests.

With the above equation, the mobility of the displacing and the displaced fluids was calculated to be 7.1. From the published curves of Dykstra Parson's paper (1950, p. 160-173) the vertical sweep efficiency indicates 63 per cent of the reservoir rock would be contacted vertically by the water.

#### Areal Sweep Efficiency

Areal or horizontal sweep efficiency is referred to as that fraction of the total area of a two-dimensional reservoir model contacted by the displaced phase at the time of displacing phase breakthrough.

The areal sweep efficiency is primarily dependent on the flood pattern to use. In Southeast Sumatra there is not a well-defined pattern, but with the present injection wells and with the production wells that will be converted into injectors a pattern close to a line drive will be formed.

For practical purposes in this study it was assumed that line drive is the flood pattern in Southeast Sumatra. The areal sweep efficiency for our field was obtained by using a correlation proposed by Muskat. The flood coverages of the line drive in this correlation vary from zero to infinity, depending on the spacing of wells within the line compared with spacing of lines. For our field the ratio of both spacings is one to one and a value of 58 per cent was obtained

for the areal sweep efficiency. As this value was corrected with information of areal sweep efficiencies from fields surrounding our unit, a value of 56 per cent for areal sweep efficiency is used for the Southeast Sumatra field in this report.

The product of the vertical sweep efficiency times the horizontal (areal) sweep efficiency and the secondary oil in place indicates that an additional volume of 2,292,000 STB of oil will be recovered by waterflooding.

#### Injection and Production Rates

It is necessary to know the anticipated injection rate to design the water-injection facilities, and the anticipated production rate must be known to calculate the economics of the secondary recovery project. The following is a discussion of the estimated injection and production rates.

Injection Rate: The water injection rate ( $i$ ) was calculated with the use of Deppe's equation for a mobility ratio other than unity. The equation assumes radial flow. This assumption is valid as most of the pressure drop occurs immediately around the well bore where the flow is radial. The equation is as follows:

$$i = \frac{7.07 k (P_{wi} - P_{wp})}{\mu_w \left( \frac{1}{M} \ln \frac{d}{r_w} + \frac{1}{M} \ln \frac{d}{r_f} + \ln \frac{r_f}{r_w} \right)}$$

where:

$i$  = water injection rate, bbls per day  
 $k$  = absolute permeability, darcies  
 $P_{wi}$  = bottom-hole injection pressure  
 $P_{wp}$  = bottom-hole producing pressure  
 $\mu_w$  = water viscosity, centipoises  
 $M$  = water-oil mobility ratio  
 $d$  = distance between wells, feet  
 $r_w$  = well-bore radius, feet  
 $r_f$  = radius of the flood front, feet

The radius of the flood front is approximated as:

$$r_f = d \sqrt{\frac{2(1-E_s)}{\pi}}$$

where:

$E_s$  = areal sweep efficiency, fractional

It could be determined from the above equation that water can be injected at 48 BPD (bbls per day) per foot of effective pay at a pressure drawdown ( $P_{wi} - P_{wp}$ ) of 1500 psia. A total rate of about 8700 BWPI (bbls water per day) can be injected into the 6 water-injection wells. The injection pressure should not exceed 2500 psia, which is the breakdown pressure on fracturing treatments. The water injection recommended for the waterflood is 5000 barrels per day. Since water injection wells No. 2 and No. 3 found a smaller pay than expected (Map 1), it is recommended to change the well Grebe No. 2 into injection as soon as possible and change those wells that water out into injection wells also.

Production Rate: The Dykstra Parson's method was used to estimate the waterflood performance ( Tables 4 and 5 and Fig. 13), as this method is better suited to our reservoir characteristics.

Calculations were made for water injection rates of 3000 BWPD (barrels of water per day), 5000 BWPD and 7000 BWPD. 5000 BWPD was used in this study, as it seems the most suitable from the economic and technical points of view..

Calculations indicate response from the waterflood will be seen in about two years, which is the time necessary to inject 0.148 pore volumes of water (free gas saturation at start of waterflood). The oil pushed into the area not contacted by water was not taken into consideration in the recovery calculations.

The production rate will increase to about 2500 BOPD after the free gas saturation is displaced. The field is expected to reach an economic limit of 3800 BOPM (barrels of oil per month) in approximately 16 years (Figure 12).

WATER SOURCE

In the Sumatra Field the Madison formation (massive dolomitic limestone) at 6500 feet is the best source of an adequate supply of water for waterflood. Two neighboring units currently have water supply wells producing from the Madison. Therefore, this formation was selected to furnish water for the flood in Southeast Sumatra. A water-supply well was drilled in C SE $\frac{1}{4}$  NE $\frac{1}{4}$  Section 24, Township 11 North, Range 32 East in December, 1969, and produced 5000 BWPD (from the 6153-6833 interval) in 24 hours, after being acidized with 15,000 gal. of 28 per cent HCL.

From the calculations it is believed about 15 million barrels will be required over the life of the flood. Of this 15 million required, about 7 million barrels will be produced water. The water supply well No. 1 seems to be capable of producing much more water than what it is required.

Because the quality of the water is good (the water contains only 5 ppm total dissolved salts and contains a very small amount of dissolved gases) no water treatment will be required except for the addition of a small amount of corrosion inhibitors and scale-preventer chemicals.

POLYMER FLOOD

Because of a relatively adverse mobility ratio (7) and a poor permeability variation (0.73) in the Southeast Sumatra Field, it was thought to be worthwhile to improve the waterflood by polymer injection. A literature survey was made on polymer flooding (see appendix).

Water soluble polymers of high molecular weight have the ability to improve the vertical efficiency of the formation which is obtained by increasing the viscosity of the injected water and/or decreasing the relative permeability to water of the reservoir rock.

Because of the lack of core studies, field cases of polymer floods in reservoirs with characteristics similar to those of Southeast Sumatra and published literature on this topic were used for estimating the amount of polymer to be used. An additional recovery of 802,000 barrels of oil was estimated with the use of a polymer slug size of 0.6 displaced pore volume (6,023,000 bbl of water with 301,200 lb dissolved in it). The recovery estimate was obtained by improving the flood

vertical efficiency from 0.63 (the actual value) to 0.85, which was obtained by Dykstra Parson's method by decreasing the mobility ratio from 7.1 to 1. This decrease of ratio was assumed as an overall flood improvement with the use of polymers. The additional recovery by polymers and the slug size were adjusted for values obtained from charts in the study on this topic published by G. Wang and B. Caudle.

Figure 12 shows an estimated production curve for the polymerflood as compared with that of the waterflood. The curve was built with information obtained from Dykstra Parson's method (Calculations - Table 6)

Stiles' method calculations for Polymerflood (waterflood with  $M = 1$ ) were also made and are recorded in the Appendix (Tables 7, 8, 9, and 10 and Fig. 14).

ECONOMICS OF WATERFLOOD AND POLYMERFLOOD

The following is a discussion of the economic evaluation of the Southeast Sumatra waterflood and polymerflood.

The waterflood and polymerflood economics (Tables 11, 12, and 13) were calculated as follows:

1. Cash flows for the waterflood production were calculated (discounted at a 10% rate and undiscounted).
2. Cash flows for the polymerflood production were calculated (discounted at a 10% rate and undiscounted).
3. Difference between the discounted polymerflood cash flow and the discounted waterflood cash flow is the incremental income from the polymerflood.
4. The payout times of the waterflood and polymerflood were calculated.

Calculations indicate the waterflood has a total discounted profit of \$1,334,694, and the polymerflood has a total discounted profit of \$2,383,957.

This is based on an undiscounted waterflood cash flow (net income) of \$2,505,902 and a discounted cash flow (net income) of \$1,607,424. The undiscounted polymerflood cash flow is \$4,613,146, and the discounted cash flow is \$3,064,522.

The total undiscounted investment for the waterflood is \$300,000 (the discounted investment is \$272,730). The total undiscounted investment for the polymerflood is \$792,000 (the discounted investment is \$680,565).

The waterflood would pay out in 2.9 years, and the polymerflood would pay out in 2.11 years.

CONCLUSIONS

The purpose of this engineering study was to determine the feasibility of waterflooding the Southeast Sumatra Field, and a way to improve it by use of polymers dissolved in the injection water.

Conclusions from the study indicate a waterflood at the Southeast Sumatra Field would be feasible, although improvement of the waterflood by use of polymers would give a greater profit.

Specific conclusions from the study are as follows:

1. Oil recovery by waterflooding (excluding primary production during 1970 and 1971) would be 2,292,000 STB.
2. Oil recovery by polymer flooding (excluding primary production during 1970 and 1971) would be 3,094,000 STB.
3. The waterflood project would pay out in 2.9 years, and the polymerflood would pay out in 2.11 years.
4. A discounted profit of \$1,334,694 would be realized by the waterflood, and a discounted profit of \$2,383,957 would be realized by the polymerflood.
5. It is recommended to polymer-flood the Southeast Sumatra Field.

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PRINCIPLES OF POLYMERFLOOD

Polymers for secondary oil recovery were introduced to the petroleum industry in 1964, after several years of laboratory and field research. Since that time they have been applied with relative success in many producing areas in the United States and several foreign countries.

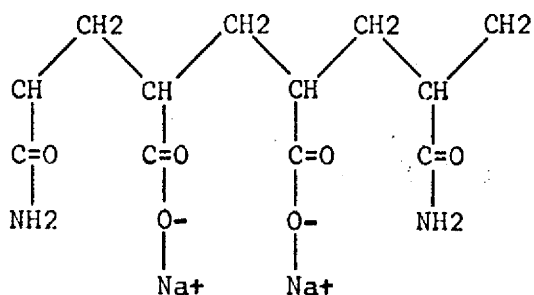
Dilute solutions of partially hydrolyzed polyacrylamides (polymers) have the ability to control water/oil mobility and increase the effectiveness of a waterflood. Mobility control appears to be due not only to an increase in viscosity brought about by the polymer but also to the effective permeability of the displacing phase being reduced because polymer molecules are adsorbed or otherwise retained in the pore channels.

Polymers are applied in calculated quantities over a predetermined portion of the flood life, rather than continuously over the entire duration of the flood. Efficient application of polymers

depends on the design of the flood project and the polymer system, based on detailed analysis of reservoir characteristics.

### Polymers Used in Waterflooding

Two basic types of polymers are being marketed and field-tested with promising results. One is an ionic polymer (polyacrylamide) and the other is a nonionic polymer (polyethelyene oxide). Between the polyacrylamide polymers and the polyethelyene oxide polymers, the polyacrylamides show the greatest mobility reduction and reduce the permeability to water of the cores following the injection of a polymer slug. Therefore, polymers used for reducing the mobility of water in secondary recovery operations are partially hydrolyzed acrylic polymers whose structure is:



These macromolecules consist of long hydrocarbon chains with acid and amide groups randomly attached to alternate carbon atoms along the chain. Molecules with molecular weights as high as  $10^7$  can be prepared with acid to amide ratios varying between 0 and 1.

The presence of ionizable COONa groups along the chain has a profound influence on molecular size when these polymers are dissolved

in water. The electrical repulsion of like charges along the polymer chain causes expansion of the molecule in alkaline solution. Since the ionization is repressed by the presence of electrolytes which screen the electrostatic repulsion, the polymer size is also greatly influenced by the ionic strength of the polymer solution. Consequently, the polymer size which in turn influences the viscosity and other physical properties of these solutions to a marked extent is dependent on the following:

1. Molecular weight
2. Acid - amide ratio
3. Ionic strength of the solution
4. pH of solution

#### Mobility Control

The efficiency of conventional waterflooding is strongly influenced by the viscosities of the reservoir fluids and the uniformity of the reservoir rock. These factors are commonly expressed in terms of the mobility ratio between water and oil, and the permeability distribution in the reservoir. The mobility of a fluid is a measure of its ability to flow. In short, the mobility of a fluid in a porous medium varies directly with the permeability  $K$  of the medium to that fluid and inversely with the viscosity  $\mu$  of the fluid, or

$$\lambda = \frac{K}{\mu}$$

The "mobility ratio" of two different fluids (e.g., water and oil) in the same porous medium is then:

$$\frac{\lambda_w}{\lambda_o}$$

The mobility ratio of water to oil  $M_{w, o}$  is:

$$\frac{\lambda_w}{\lambda_o} = \frac{\frac{K_w}{\mu_w}}{\frac{K_o}{\mu_o}} = \frac{K_w \mu_o}{K_o \mu_w}$$

A low-viscosity fluid, such as water, has a high mobility compared with that of a viscous oil. As a result, plain water or brine injected into an oil reservoir will tend to "finger through" and by-pass the oil. This tendency will be greater at high mobility ratios. The effect of an adverse mobility ratio on flood efficiency is magnified in non-uniform reservoirs, because the high mobility of water causes it to break through rapidly to producing wells via the more permeable zones.

Once water starts moving through these zones, their water saturation and effective permeability to water are increased. Progressively larger volumes of water are diverted from the tighter zones, and producing watercuts rise rapidly to the point of economic limit, leaving much of the recoverable oil still in place.

#### Effect of Polymers on Oil Recovery

Reducing the mobility of the injected fluid improves (1) the volumetric sweep efficiency or conformance and (2) the displacement efficiency in the swept zone.

In medium to high gravity oil reservoirs, where mobility ratios are only moderately adverse, non-uniform permeability distribution is commonly recognized as the major source of waterflood inefficiency.

This reservoir heterogeneity is usually thought of as being vertically distributed and is treated as such in the more widely used prediction methods. Areal sweep efficiency, the other source of conformance inefficiency, is to a large degree dependent on flood pattern and is not often a major factor in low viscosity oil reservoirs.

In floods where permeability heterogeneity is the dominant factor influencing efficiency, reduction of water mobility can yield improvements in recovery even in cases where mobility ratios are near unity. Solutions of polymers compensate for permeability distribution by reducing the rate at which the injection fluid moves through high permeability zones.

When a dilute solution of polymers is pumped into an injection well, it will preferentially enter the section where the permeability to water is greatest. This may be a section of high matrix permeability or a zone where low oil saturation results in higher than normal permeability to water. As the solution moves out from the well bore in this section, the total resistance to the entry of additional fluid will increase as a result of low fluid mobility. The tendency of this section to take an increasing proportion of the total injected fluid is reduced, and a more uniform flood front is obtained. The result is improved oil recovery due to reduced water cut and increased economic life for the flood.

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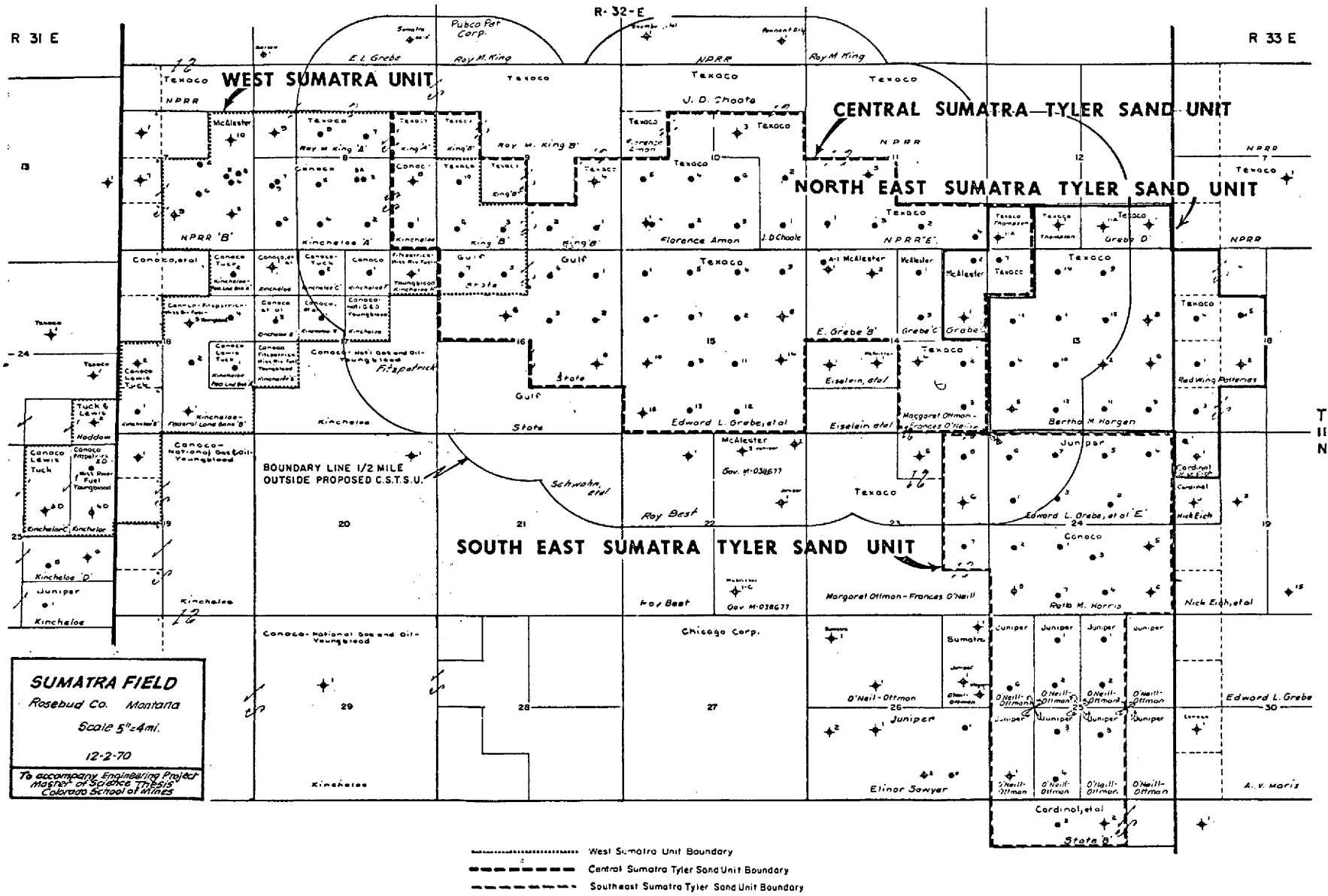
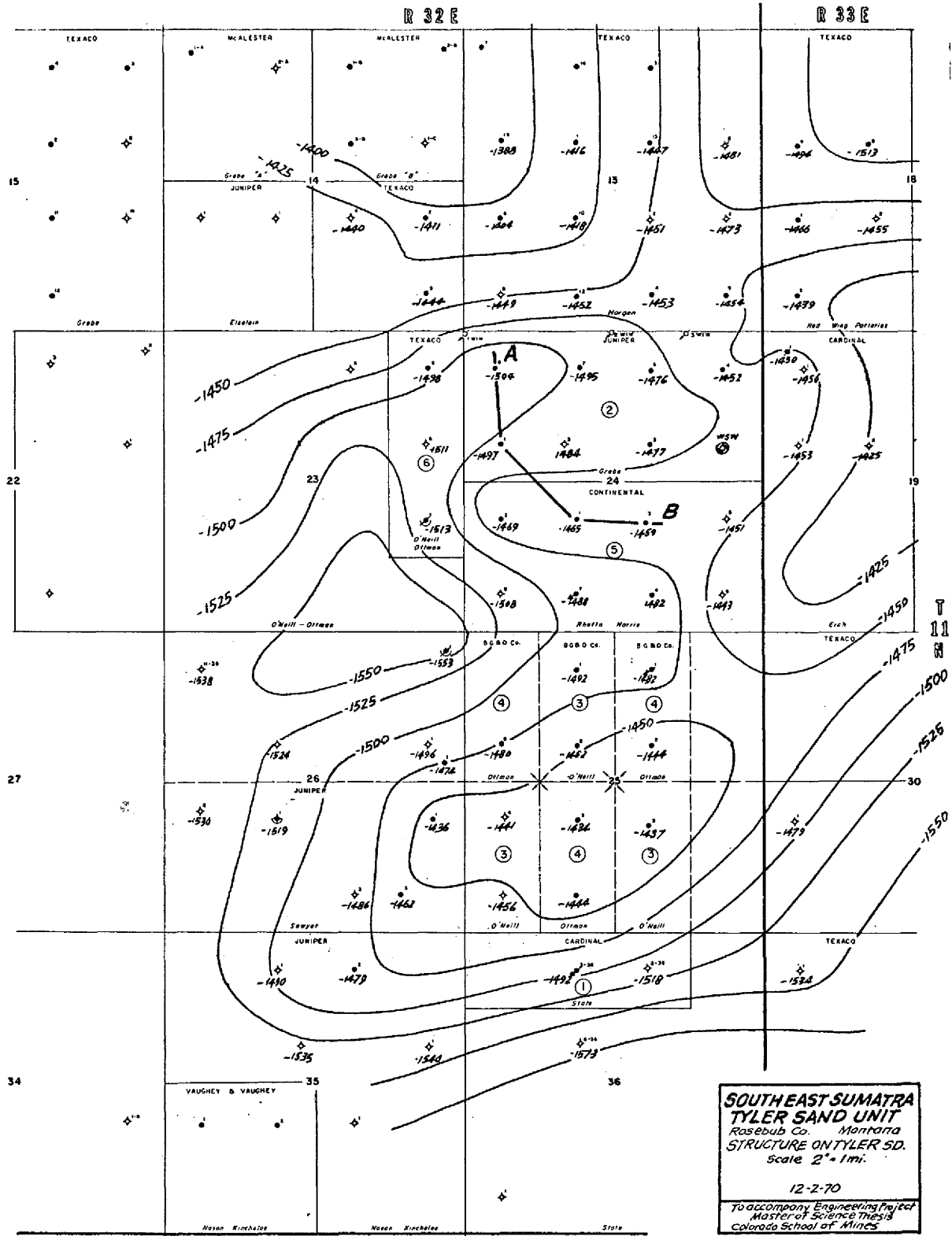


Figure 1: Units in Sumatra Field  
(Buttes Gas and Oil Co.)



- Proposed Unit Boundary
- ③ Tract Number
- Tyler Sd Producing Well, with Tyler Subsea Datum
- Oil Well Producing from Fm. other than Tyler
- Temporarily Abandoned Producer
- Abandoned Oil Well
- Tyler Well to be converted to injection
- Water Injection Well to be drilled
- Water Supply Well to be drilled
- ◇ Dry Hole

Figure 2: Southeast Sumatra Field Structure Map (Buttes Gas and Oil Co.)

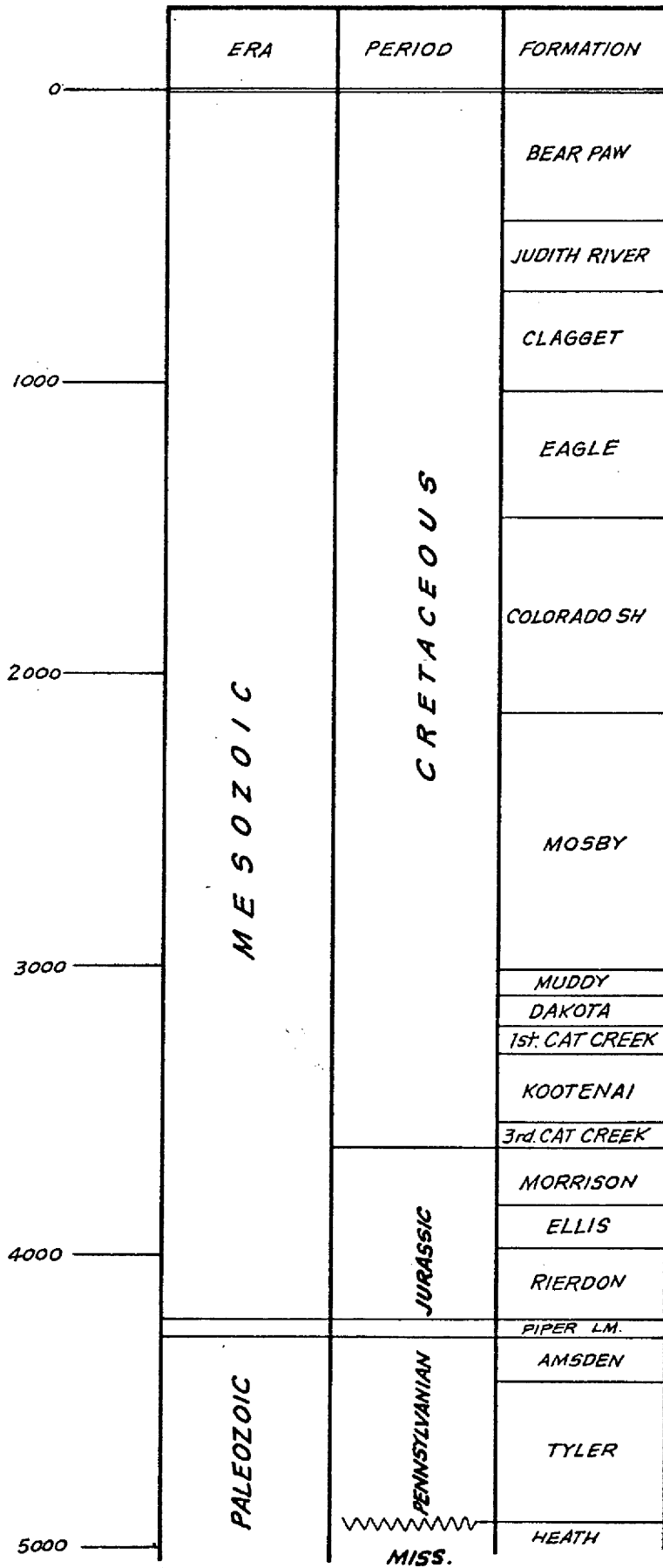
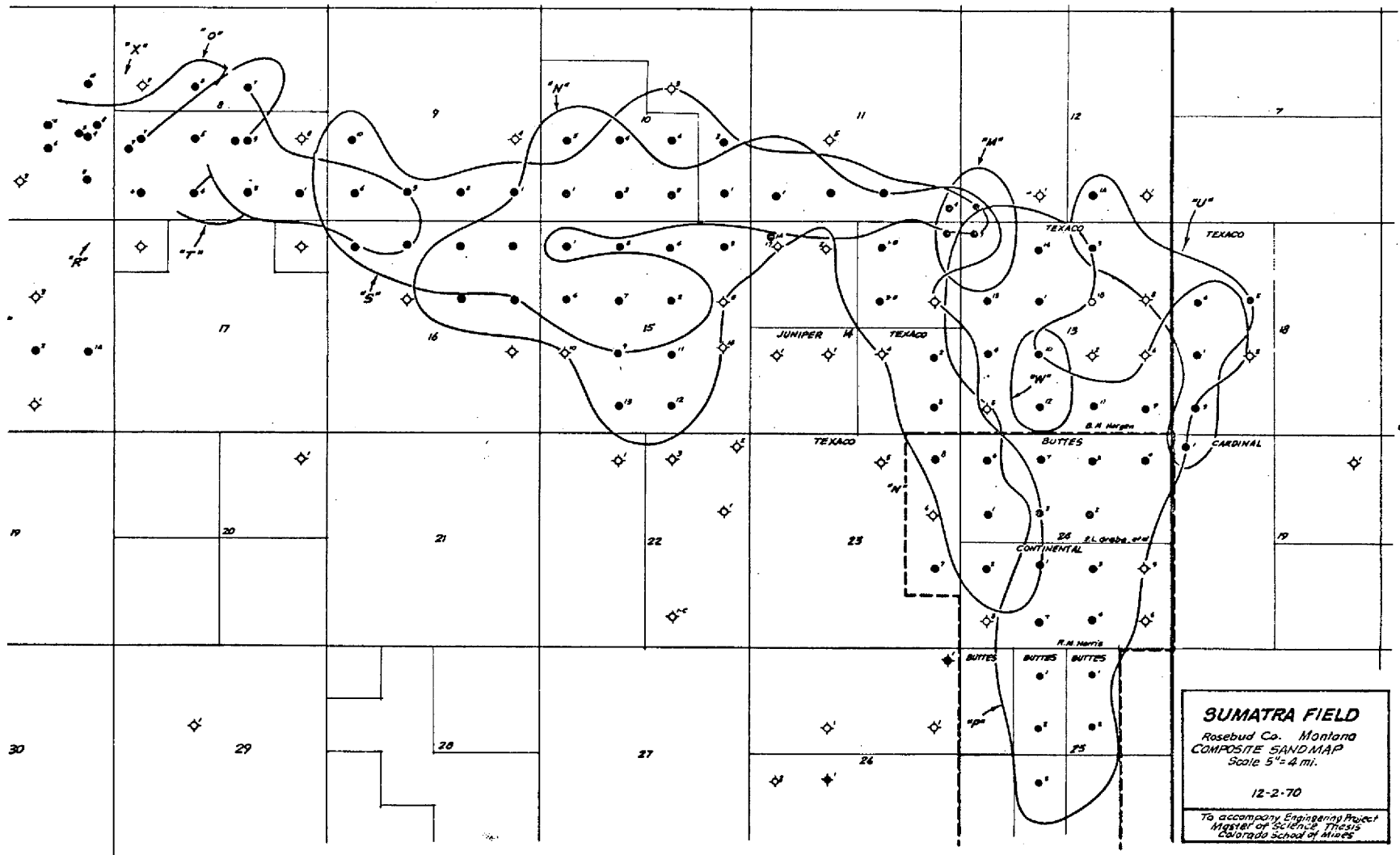


Figure 3: Geologic Stratigraphic Section of Southeast Sumatra Field (Buttes Gas and Oil Co.)

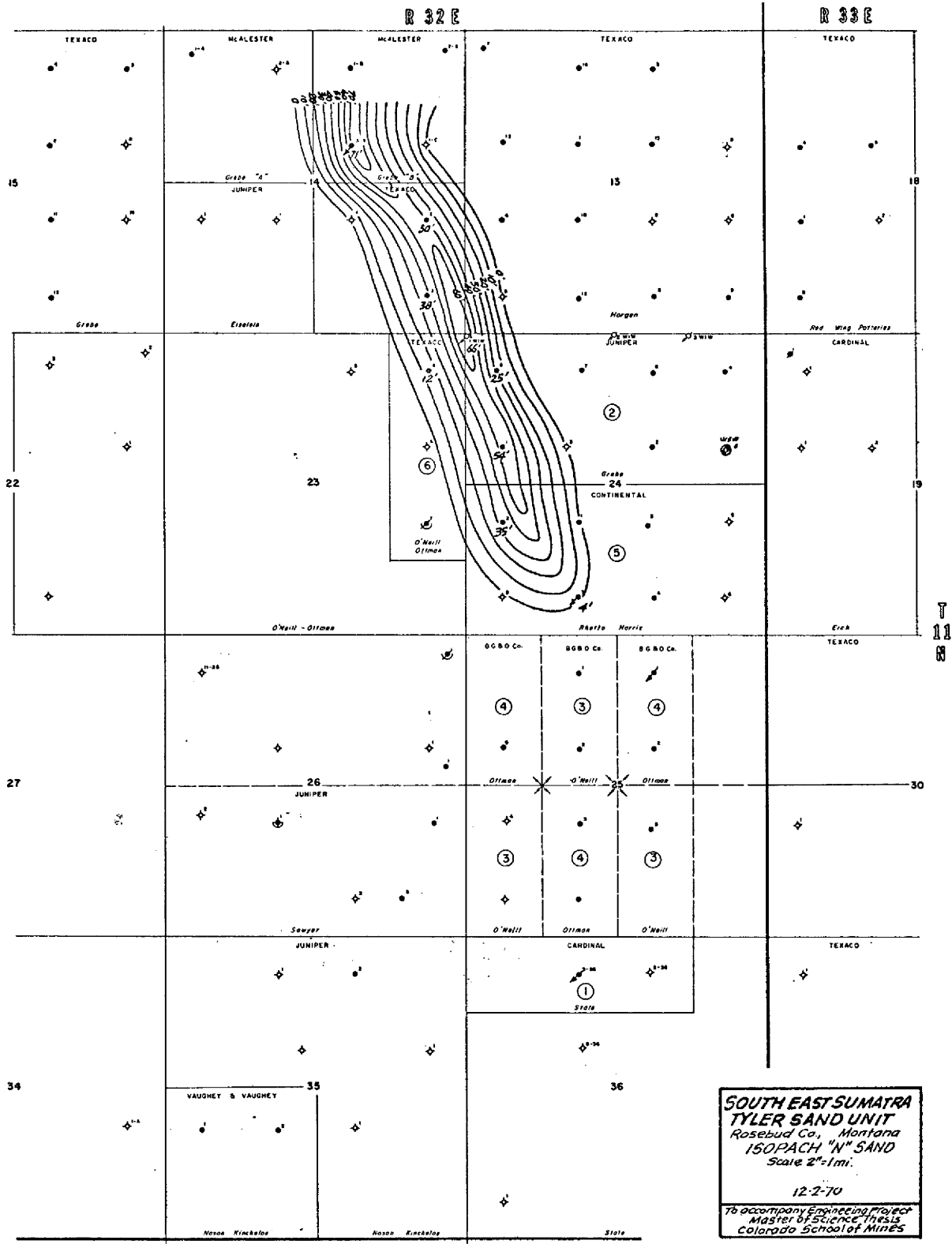
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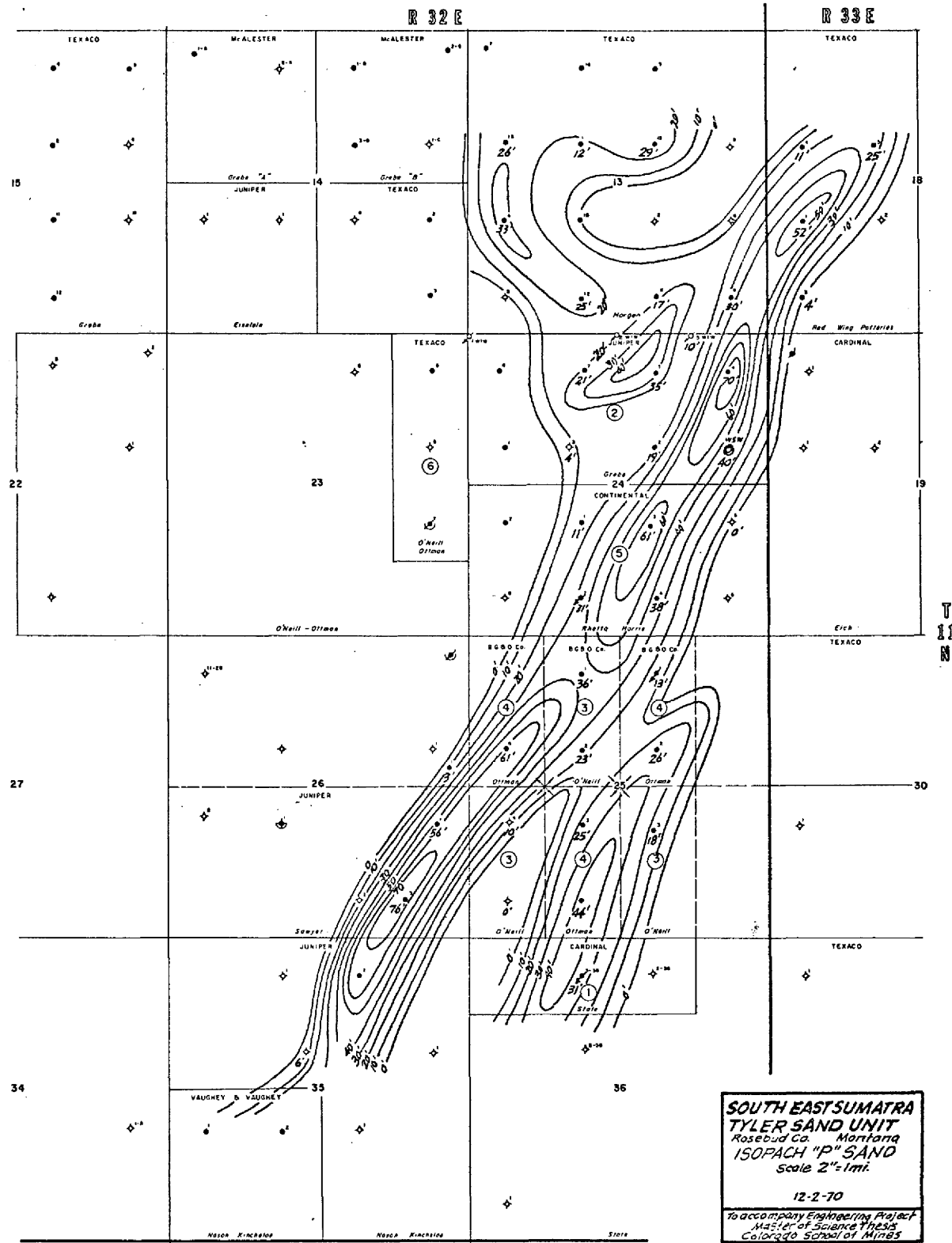
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Figure 4: Composite Sand Map of Sumatra Field (Buttes Gas and Oil Co.)



- ① Proposed Unit Boundary
- ① Tract Number
- Tyler Sd Producing Well, with Tyler Subsea Datum
- Oil Well Producing from Fm. other than Tyler
- Temporarily Abandoned Producer
- ◆ Abandoned Oil Well
- ◆ Tyler Well to be converted to injection
- ◆ Water Injection Well to be drilled
- ◆ Water Supply Well to be drilled
- ◆ Dry Hole

Figure 5: Southeast Sumatra  
Isopach Map  
"N" Sand  
(Buttes Gas and Oil Co.)



- ① Proposed Unit Boundary
- ② Tract Number
- Tyler Sd Producing Well, with Tyler Subsea Datum
- ⊙ Oil Well Producing from Fm. other than Tyler
- ⊕ Temporarily Abandoned Producer
- ⊖ Abandoned Oil Well
- ⊗ Tyler Well to be converted to injection
- ⊘ Water Injection Well to be drilled
- ⊙ Water Supply Well to be drilled
- ◇ Dry Hole

Figure 6: Southeast Sumatra  
Isopach Map  
"P" Sand  
(Buttes Gas and Oil Co.)

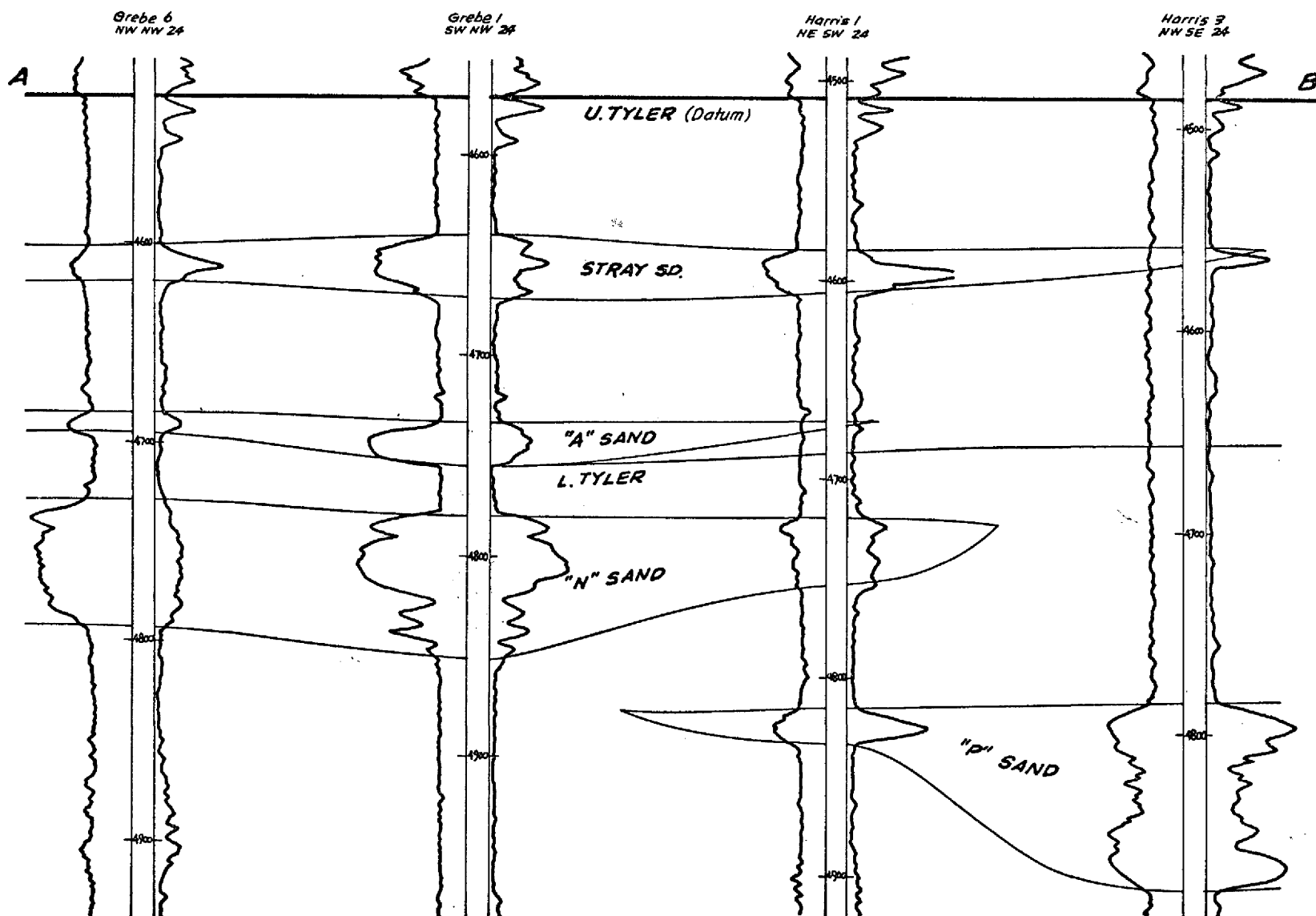
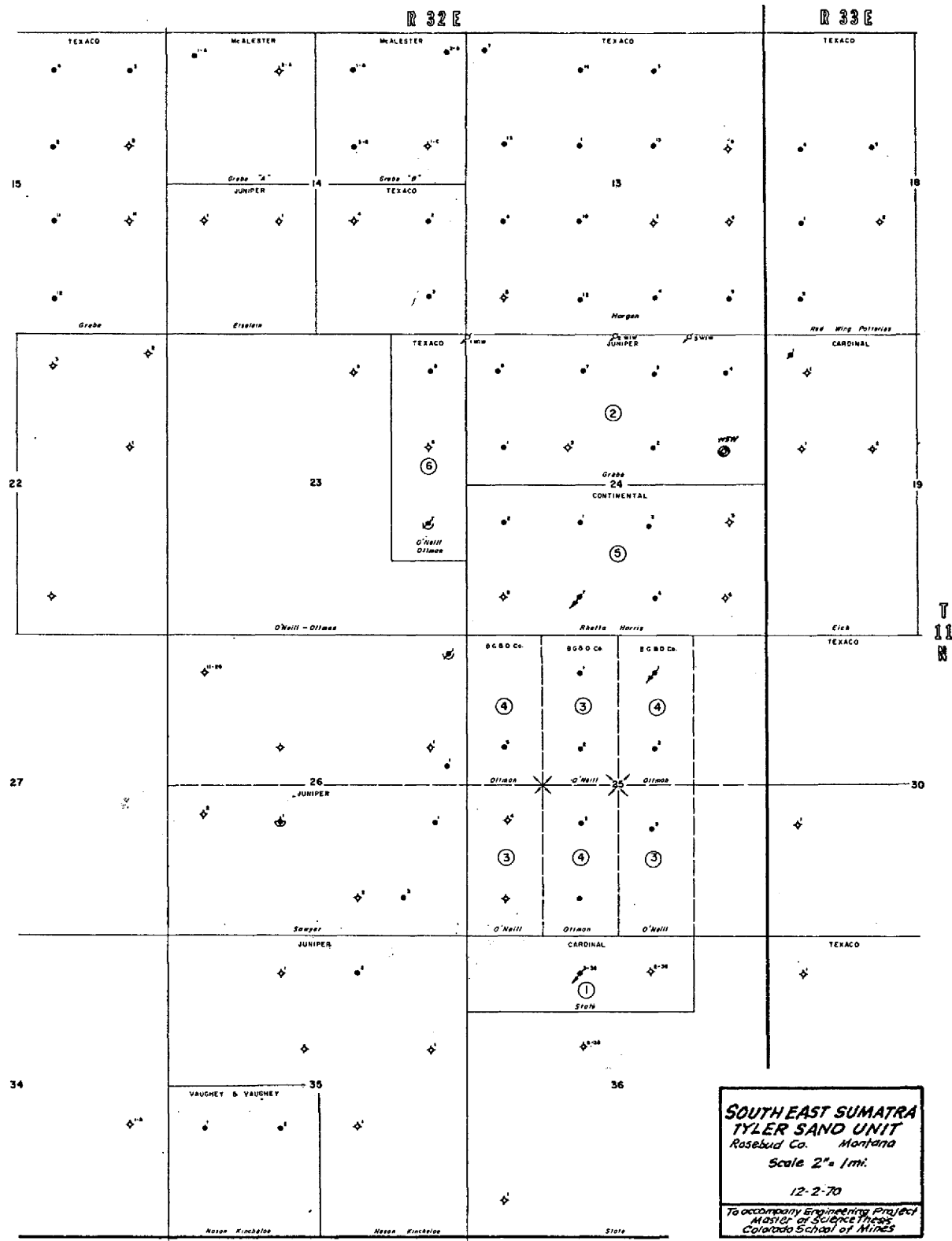


Figure 7: Southeast Sumatra  
 Typical Cross Section  
 (Buttes Gas and Oil Co.)



- Proposed Unit Boundary
- ③ Tract Number
- Tyler Sd Producing Well, with Tyler Subsea Datum
- Oil Well Producing from Fm. other than Tyler
- Temporarily Abandoned Producer
- Abandoned Oil Well
- Tyler Well to be converted to injection
- Water Injection Well to be drilled
- Water Supply Well to be drilled
- ◇ Dry Hole

Figure 8: Southeast Sumatra Field  
Location of Wells  
(Buttes Gas and Oil Co.)

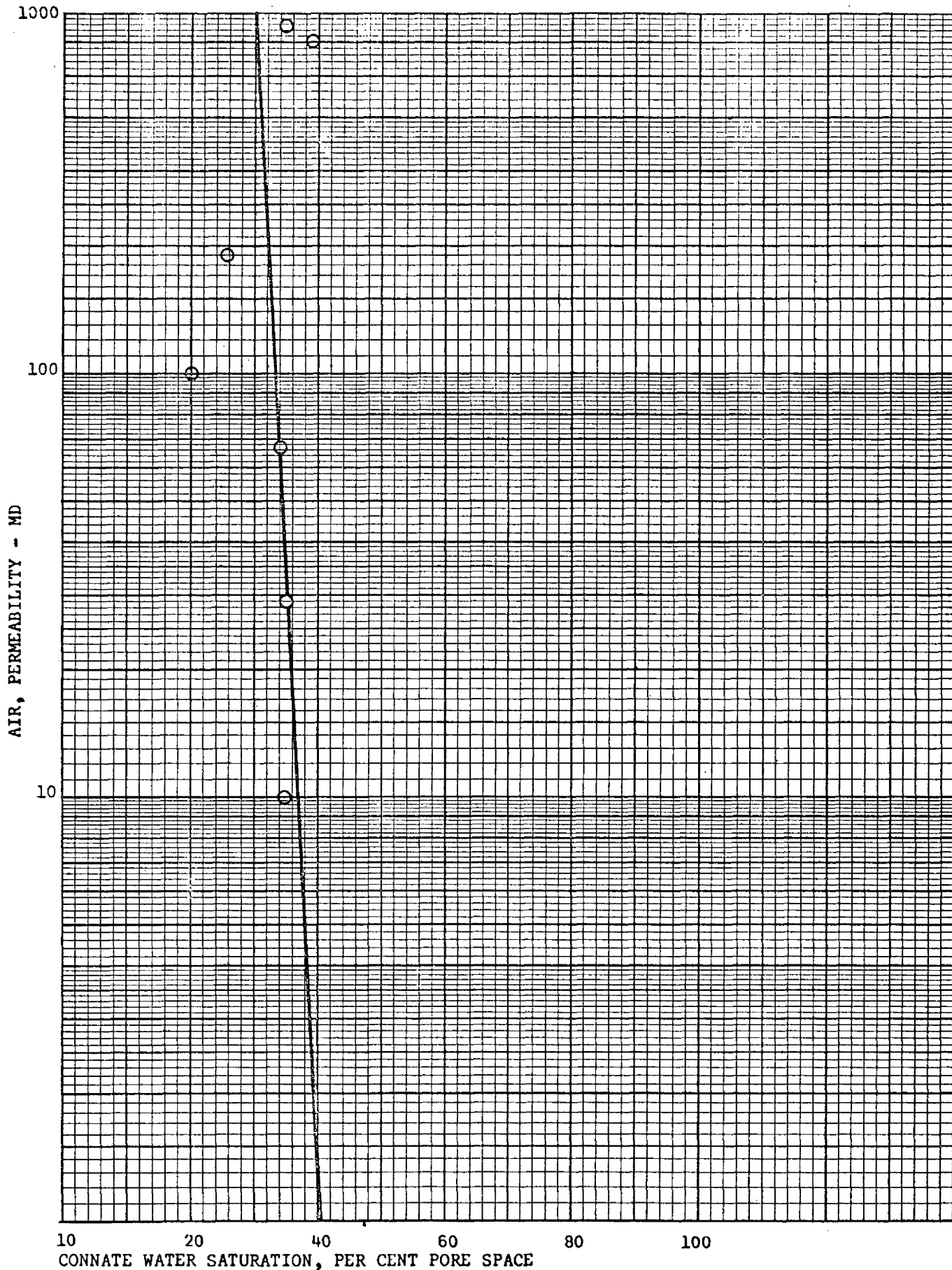


Figure 9: Sumatra Field  
Permeability vs Connate Water Saturation  
(Buttes Gas and Oil Co.)

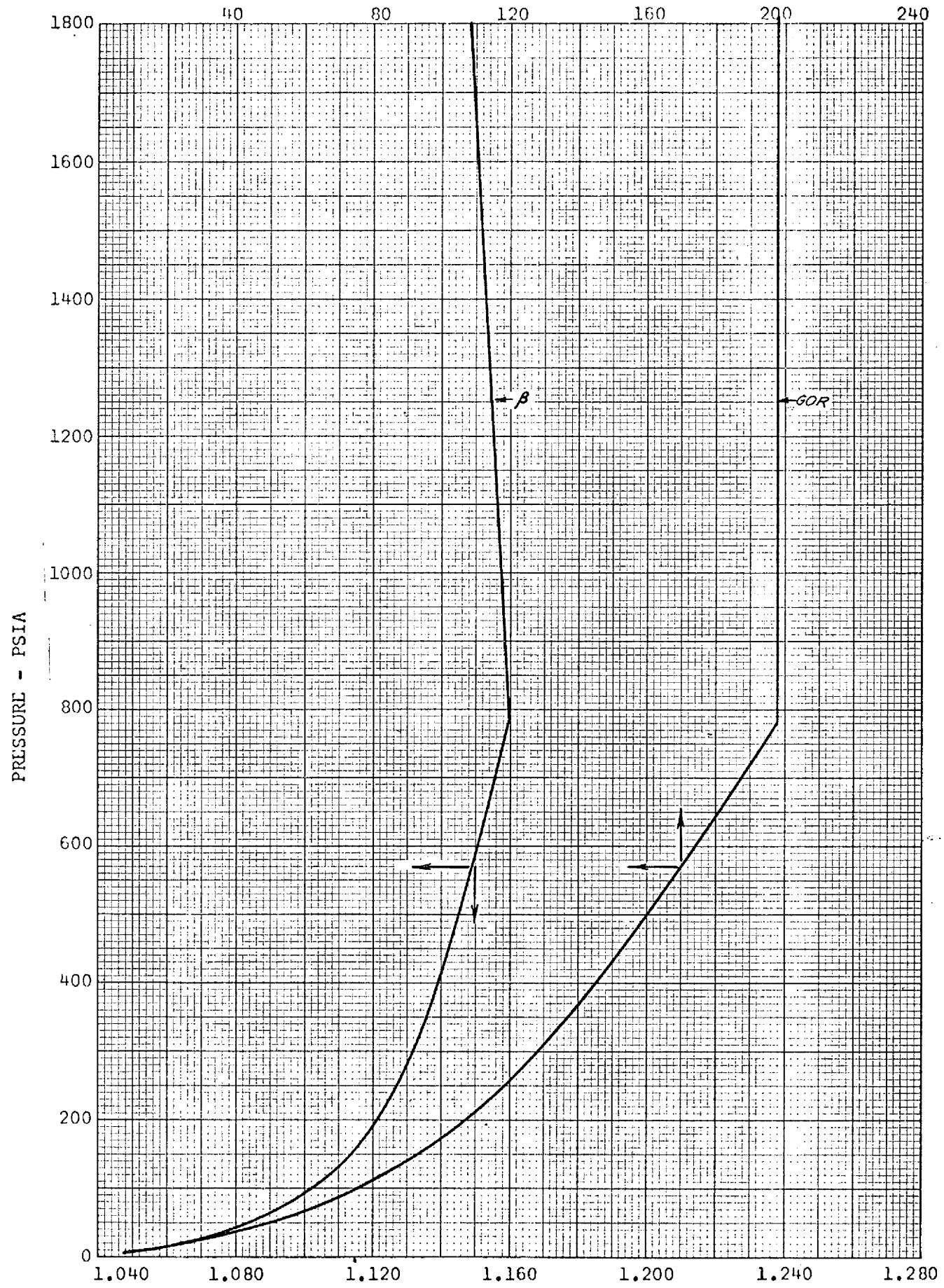
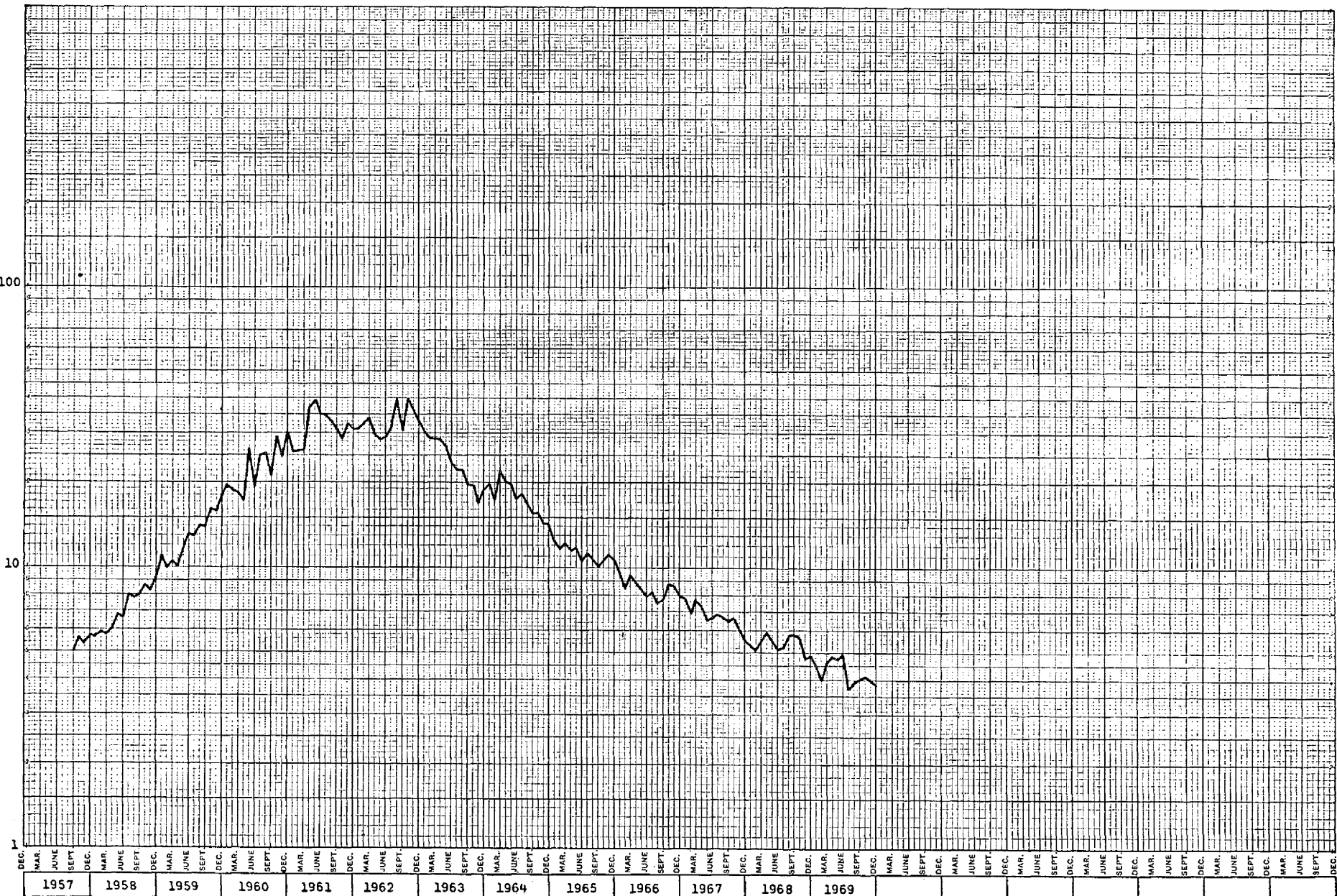


Figure 10: Formation Volume Factor and Solution GOR vs Reservoir Pressure (Buttes Gas and Oil Co.)

FORMATION VOLUME FACTOR,  $\beta$ .

OIL PRODUCTION, BOPM x 10<sup>-3</sup>



OIL PRODUCTION, BOPM  $\times 10^{-3}$

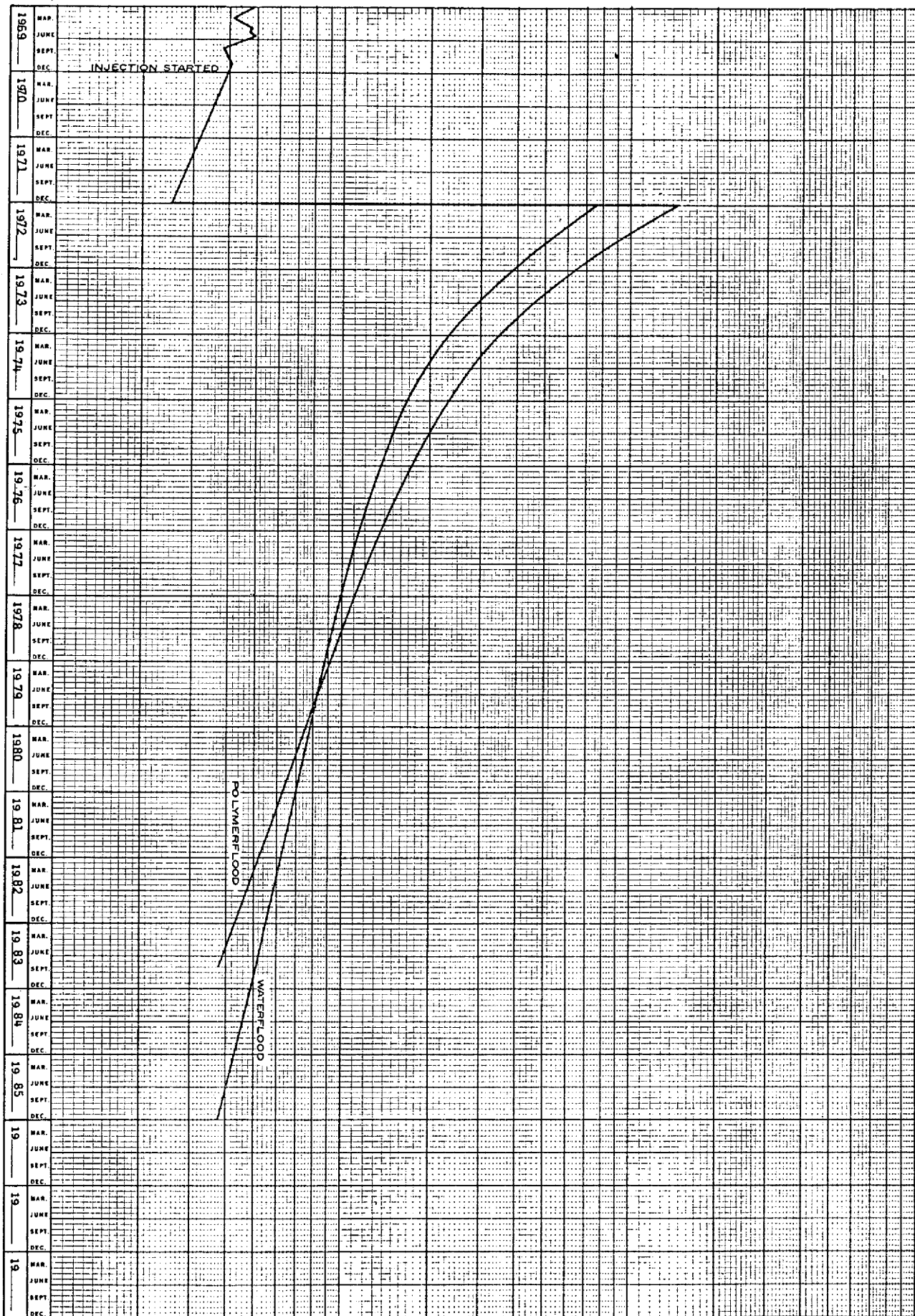
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1000

100

10

1



TIME YEARS

50

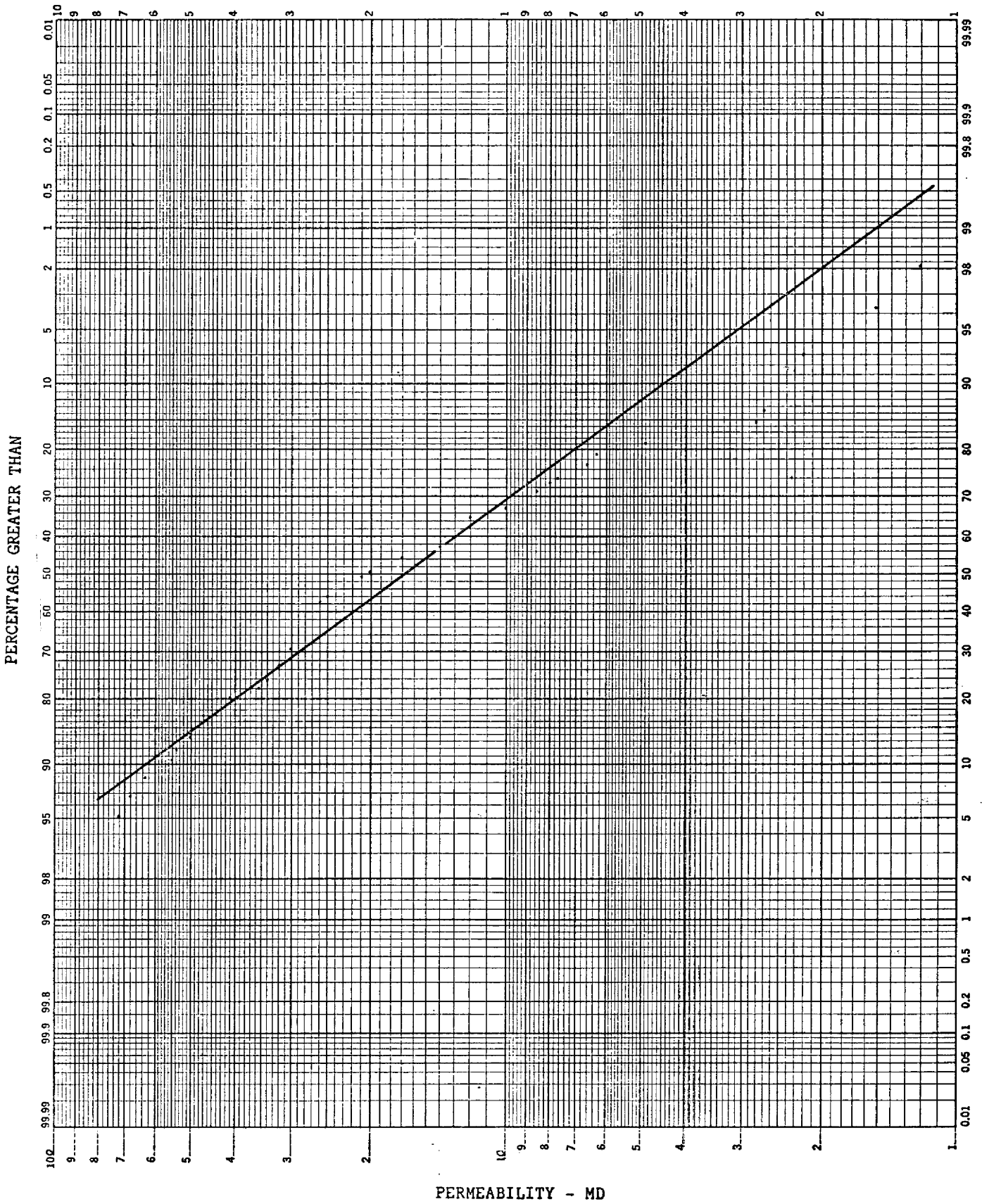
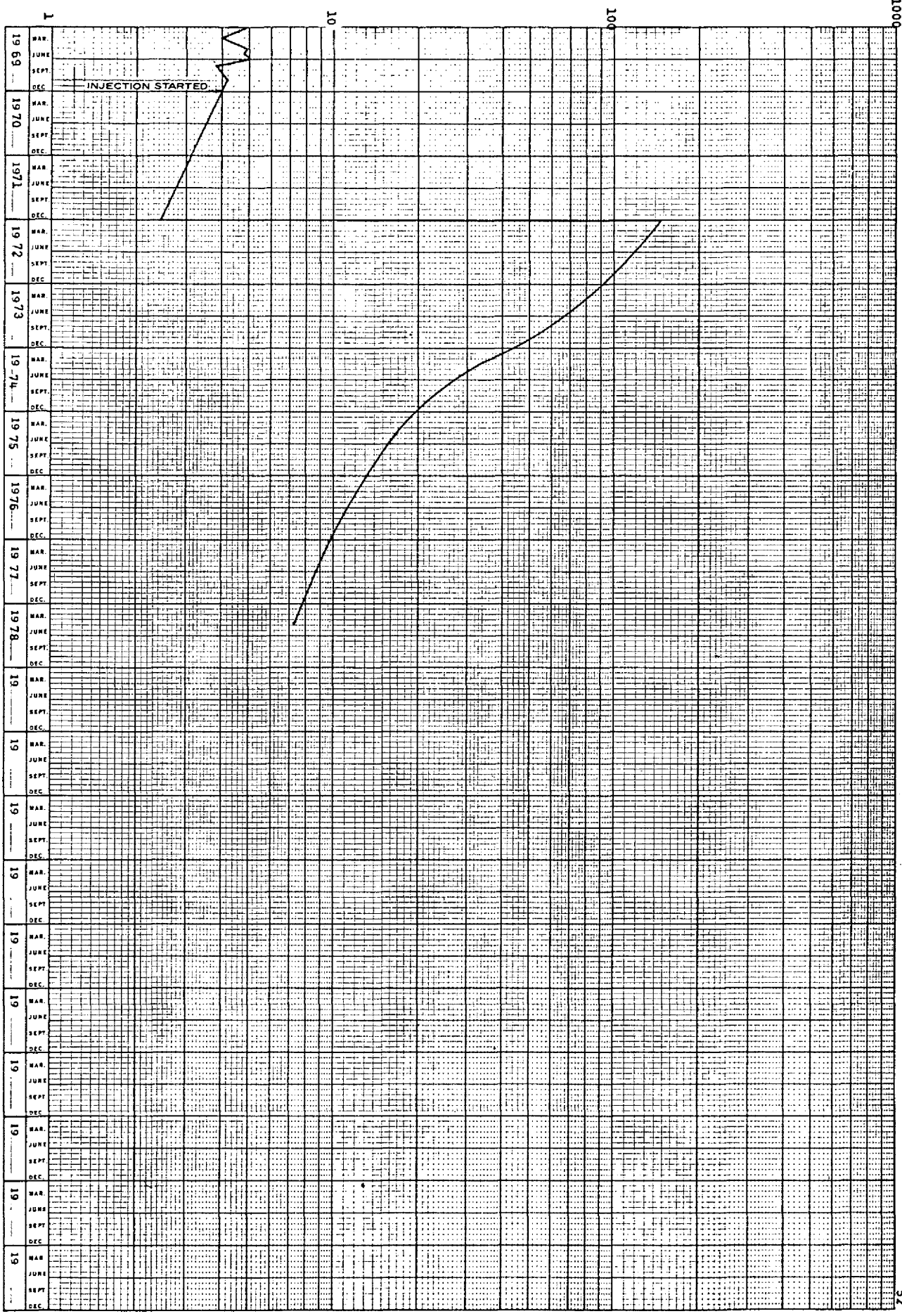


Figure 13: Permeability Variation Curve

OIL PRODUCTION, BOPM x 10<sup>-3</sup>

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52



TIME YEARS

Elkton II - Waterflood Production - Oil Field - West

	Montana State #5	Grebe #5
Date Sampled	5-27-54	11-5-53
Static Reservoir Pressure	1172 psig @ 4870'	1394 psig @ 4585'
Reservoir Temperature	168 F.	162 F.
Sand Lens	"s"	"n"
Saturation Pressure	775 psig @ 168 F.	800 psig @ 165 F.
Solution GOR	165	206
Formation Volume Factor	1.1406	1.1665
Viscosity - cps.	1.99	1.324

HYDROCARBON ANALYSIS

	<u>Reservoir Fluid</u>		<u>Reservoir Fluid</u>	
	<u>Mol %</u>	<u>STO</u>	<u>Mol %</u>	<u>STO</u>
CO <sub>2</sub>	0.49	0.12	- - -	- - -
C <sub>1</sub>	10.77	2.67	12.23	0.11
C <sub>2</sub>	3.84	1.42	4.92	0.10
C <sub>3</sub>	6.10	2.45	7.79	0.76
i C <sub>4</sub>	1.13	0.54	1.15	0.31
n C <sub>4</sub>	4.75	2.19	5.70	1.50
i C <sub>5</sub>	1.79	0.96	2.17	.80
n C <sub>5</sub>	2.45	1.30	2.82	4.19
C <sub>6</sub>	68.67	88.35	63.22	92.23
Density, g/cc		0.8696		- - -
Degrees API @ 60 F.		31.1		- - -
Molecular Weight		242		172

TABLE 1: Sumatra Field,  
Reservoir Fluid  
Analysis,  
Subsurface Samples

Grebe Well "A" No. 2.  
C SW NE Section 15 - 11-N-32-E  
Producing Interval: 4723-4763; 4800-4840  
Sampled October 22, 1952

Specific Gravity @ 60/60 F.	0.858
API Gravity @ 60 F.	33.4
Pour Point, Degrees Fahrenheit	45
Kinematic Viscosity, Centipoises @ 70 F.	18.6
Kinematic Viscosity, Centipoises @ 100 F.	13.8
Kinematic Viscosity, Centipoises @ 140 F.	4.8

TABLE 2: Sumatra Field  
Partial Crude Analysis

Acre Feet of Oil Sand	28,667 Acre feet
Primary Oil Recovery	2,650,000 Barrels
Primary Recovery Factor	92.4 B/AF
Porosity	12.4 Percent
Permeability	15.8 Percent
Connate Water Saturation	36 Percent
Discovery Pressure	850 Psi
Bubble Point Pressure	790 Psi
Initial Formation Oil Volume Factor	1.16
Formation Oil Volume Factor @ Beginning of Flood	1.08
Solution Gas-Oil Ratio	198.5 C.F./Bbl
Crude Gravity	32 API
Initial Oil Viscosity	1.98 cp @ 189 F.
Oil Viscosity @ 50 Psi	2.525 cp
Specific Gravity of Gas	2.950 @ 169 F.

TABLE 3: Southeast Sumatra  
Field, General Data

(1) Interval Equal Thickness	(2) K Descending Order	(3) Fract. Greater Than	(4) % Greater Than
1	142	1/59	1.69
2	124	2/59	3.38
3	71	3/59	5.07
4	68	4/59	6.76
5	63	5/59	8.45
6	55	6/59	10.14
7	54	7/59	11.83
8	50	8/59	13.52
9	48	9/59	15.21
10	47	10/59	16.90
11	41	11/59	18.59
12	41	12/59	20.28
13	35	13/59	21.97
14	34	14/59	23.66
15	33	15/59	25.35
16	32	16/59	27.04
17	32	17/59	28.73
18	31	18/59	30.42
19	30	19/59	32.11
20	30	20/59	33.80
21	28	21/59	35.49
22	27	22/59	37.18
23	26	23/59	38.87
24	26	24/59	40.56
25	26	25/59	42.25
26	25	26/59	43.94
27	25	27/59	45.63
28	22	28/59	47.32
29	21	29/59	49.01
30	20	30/59	50.70
31	20	31/59	52.39
32	17	32/59	54.08
33	17	33/59	55.77
34	14	34/59	57.46
35	14	35/59	59.15
36	14	36/59	60.84
37	13	37/59	62.53
38	12	38/59	64.22
39	11	39/59	65.91
40	10	40/59	67.60
41	9.8	41/59	69.29
42	8.5	42/59	70.98
43	8.0	43/59	72.67
44	7.7	44/59	74.36
45	7.7	45/59	76.05
46	6.7	46/59	77.14
47	6.3	47/59	79.43
48	4.9	48/59	81.82
49	3.5	49/59	82.81
50	2.8	50/59	84.50

TABLE 4: Southeast Sumatra Field  
Permeability Variation Data

(1) Interval Equal Thickness	(2) K Descending Order	(3) Fract. Greater Than	(4) % Greater Than
51	2.7	51/59	86.19
52	2.7	52/59	87.88
53	2.3	53/59	89.57
54	2.3	54/59	91.26
55	2.2	55/59	92.95
56	2.2	56/59	94.64
57	1.5	57/59	96.33
58	1.2	58/59	98.30

TABLE 4: Continued

(1)	(2)	(3)	(4)	(5)
WOR bbl/STB	Producing WOR (WOR x $\beta_0$ )	Coverage $\bar{C}$	$\frac{N}{P}$ Recov. Without Correlation (T.R.O. x $\bar{C}$ ) STB	$\Delta \frac{N}{P}$ STB
0.1	0.108	0.015	54600	54600
0.2	0.216	0.030	109200	54600
0.5	0.540	0.060	218400	109200
1.0	1.080	0.095	345800	127400
2.0	2.160	0.160	582000	236200
5.0	5.400	0.290	1056000	474000
10.0	10.800	0.430	1565000	509000
25.0	27.000	0.630	2292000	727000
50.0	54.000	0.740	2694000	402000
100.0	108.000	0.830	3021000	327000

Oil in place after primary = 6,500,000 STB  
T.R.O. = Total recoverable oil = oil in place after primary x areal sweep efficiency  
\*T.R.O. = 6,500,000 x 0.56 = 3,640,000 STB  
 $q_w$  = water injection rate = 5,000 BWPD

TABLE 5: Southeast Sumatra Field  
Waterflood Performance (M = 7.1)  
Standard Dykstra Parsons Method

(6) $(WOR)(\Delta N_p)$ STB	(7) $W_p = \Sigma(WOR)(\Delta N_p)$ STB	(8) $W_i = W_p + \beta_o N_p$ STB	(9) $t = W_i/q_w$ Time to produce $N_p$ days	(10) Prod. Rate BOPD
5900	5900	64900	14	3900
11800	17700	135700	15	3640
59000	76700	312570	35	3120
137600	214300	587800	55	2317
510000	724300	1352900	114	2071
2560000	3284300	4424900	615	700
5497000	8781300	10471500	1210	421
19656000	28437300	30913700	4090	178
21654000	50091300	53000900	4378	92
35316000	85407300	88669900	7173	46

TABLE 5: Continued

(1)	(2)	(3)	(4)	(5)
WOR bbl/STB	Producing WOR (WOR x $\beta_o$ )	Coverage $\bar{C}$	$N_p$ Recov. Without Correlation (T.R.O.* x $\bar{C}$ ) STB	$\Delta N_p$ STB
0.1	0.108	0.09	327600	327600
0.2	0.216	0.14	182000	182000
0.5	0.540	0.23	837200	327600
1.0	1.080	0.34	1237600	400400
2.0	2.160	0.47	1710800	473200
5.0	5.400	0.64	2330000	619200
10.0	10.800	0.74	2694000	364000
25.0	27.000	0.85	3094000	400000
50.0	54.000	0.91	3312000	218000
100.0	108.000	0.94	3422000	110000

TABLE 6: Southeast Sumatra Field  
 Polymerflood Performance (M =1)  
 Standard Dykstra Parsons Method

(6) (WOR)( $\Delta N_p$ ) STB	(7) $W_p = \Sigma(\text{WOR})(\Delta N_p)$ STB	(8) $W_i = W_p + \beta_o N_p$ STB	(9) $t = W_i/q_w$ Time to produce $\Delta N_p$ days	(10) Prod. Rate BOPD
35380	35380	389180	78	4200
39300	74680	625080	47	3830
176900	251580	1155780	106	3090
432400	683980	2020580	173	2314
1022100	1706080	3553680	307	1541
3343700	5049780	7566180	802	772
3931200	8980980	11890380	865	420
10800000	19780980	23222380	2246	178
11772000	31552980	35129980	2400	91
11880000	43432980	47128740	2399	45

TABLE 6: Continued

(1) Cum. Thickness Feet	(2) h Fract. of Cum. Thickness	(3) K Permeability Milidarcies	(4)* Kh <sub>o</sub> Permeability Capacity	(5) ΔC Increment of Total Capacity	(6) C Cum. Capacity Fraction
1	0.01724	142	142	0.0927	0.0927
2	0.03448	124	124	0.0809	0.1736
3	0.05172	71	71	0.0463	0.2199
4	0.06896	68	68	0.0444	0.2643
5	0.08620	63	63	0.0411	0.3054
6	0.10344	55	55	0.0359	0.3413
7	0.12068	54	54	0.0352	0.3765
8	0.13792	50	50	0.0326	0.4091
9	0.15516	48	48	0.0313	0.4404
10	0.17240	47	47	0.0307	0.4711
11	0.18964	41	41	0.0268	0.4979
12	0.20688	41	41	0.0268	0.5247
13	0.22412	35	35	0.0228	0.5475
14	0.24136	34	34	0.0222	0.5697
15	0.25860	33	33	0.0215	0.5912
16	0.27204	32	32	0.0209	0.6121
17	0.28928	32	32	0.0209	0.6330
18	0.30652	31	31	0.0202	0.6532
19	0.32376	30	30	0.0196	0.6728
20	0.34180	30	30	0.0190	0.6924
21	0.35904	28	28	0.0183	0.7107
22	0.37628	27	27	0.0176	0.7283
23	0.39352	26	26	0.0170	0.7453
24	0.41076	26	26	0.0170	0.7623
25	0.42800	26	26	0.0170	0.7793
26	0.44524	25	25	0.0168	0.7956
27	0.46248	25	25	0.0168	0.8119
28	0.47972	22	22	0.0144	0.8263
29	0.49696	21	21	0.0137	0.8400
30	0.51920	20	20	0.0130	0.8530
31	0.53644	20	20	0.0130	0.8660
32	0.55368	17	17	0.0111	0.8771
33	0.57092	17	17	0.0111	0.8882

TABLE 7: Southeast Sumatra Field  
Calculation of Capacity Distribution  
Stiles' Method

(1) Cum. Thickness Feet	(2) h Fract. of Cum. Thickness	(3) K Permeability Milidarcies	(4)* Kh. Permeability Capacity	(5) $\Delta C$ Increment of Total Capacity	(6) C Cum. Capacity Fraction
34	0.58816	14	14	0.0091	0.8973
35	0.50540	14	14	0.0091	0.9084
36	0.62264	14	14	0.0091	0.9155
37	0.63988	13	13	0.0085	0.9240
38	0.65712	12	12	0.0078	0.9318
39	0.67436	11	11	0.0072	0.9390
40	0.69360	10	10	0.0065	0.9485
41	0.71084	9.8	9.8	0.0064	0.9519
42	0.72808	8.5	8.5	0.0055	0.9574
43	0.74532	8.0	8.0	0.0052	0.9626
44	0.76256	7.7	7.7	0.0050	0.9676
45	0.77980	7.7	7.7	0.0050	0.9726
46	0.79704	6.7	6.7	0.0044	0.9770
47	0.81428	6.3	6.3	0.0041	0.9811
48	0.83152	4.9	4.9	0.0032	0.9843
49	0.84876	3.5	3.5	0.0023	0.9866
50	0.86200	2.8	2.8	0.0018	0.9884
51	0.87924	2.7	2.7	0.0017	0.9901
52	0.89648	2.7	2.7	0.0017	0.9918
53	0.91372	2.3	2.3	0.0015	0.9933
54	0.93096	2.3	2.3	0.0015	0.9948
55	0.94820	2.2	2.2	0.0014	0.9962
56	0.96544	2.2	2.2	0.0014	0.9976
57	0.98268	1.5	1.5	0.0010	0.9985
58	0.99992	1.2	1.2	0.0008	0.1000

\* h = bed Thickness = 1 foot

TABLE 7: Continued

(1) h Fract. of Cum. Thickness	(2) $K^1$ Dimensionless Permeability	(3) C Cum. Capacity Fraction	(4) $K^1 h$	(5) $K^1 h + (1-C)$	(6) Rec. Fract. of Total (5)/(2)
0.017	5.38	0.0927	0.091	0.098	0.0182
0.034	4.70	0.1736	0.160	0.986	0.2098
0.052	2.69	0.2199	0.140	0.920	0.3420
0.069	2.57	0.2643	0.177	0.913	0.3552
0.086	2.39	0.3054	0.205	0.900	0.3765
0.103	2.08	0.3413	0.214	0.873	0.4197
0.121	2.04	0.3765	0.247	0.871	0.4269
0.138	1.89	0.4091	0.261	0.851	0.4502
0.155	1.82	0.4404	0.282	0.842	0.4626
0.172	1.78	0.4711	0.306	0.835	0.4691
0.190	1.55	0.4979	0.295	0.797	0.5141
0.207	1.55	0.5247	0.321	0.796	0.5135
0.224	1.32	0.5475	0.296	0.749	0.5674
0.241	1.29	0.5697	0.311	0.741	0.5744
0.259	1.25	0.5912	0.324	0.733	0.5864
0.272	1.21	0.6121	0.329	0.717	0.5925
0.289	1.21	0.6330	0.350	0.717	0.5925
0.306	1.17	0.6532	0.358	0.705	0.6025
0.324	1.14	0.6728	0.369	0.707	0.6201
0.342	1.14	0.6924	0.390	0.698	0.6123
0.360	1.06	0.7107	0.381	0.670	0.6320
0.376	1.02	0.7283	0.383	0.655	0.6422
0.393	0.98	0.7453	0.385	0.639	0.6520
0.411	0.98	0.7623	0.403	0.640	0.6520
0.428	0.98	0.7793	0.419	0.639	0.6520
0.445	0.95	0.7956	0.423	0.627	0.6600
0.462	0.95	0.8119	0.439	0.626	0.6600
0.480	0.83	0.8263	0.398	0.571	0.6879
0.497	0.80	0.8400	0.397	0.556	0.6950
0.520	0.76	0.8530	0.395	0.541	0.7118
0.537	0.76	0.8660	0.408	0.541	0.7118
0.554	0.64	0.8771	0.354	0.476	0.7437
0.571	0.64	0.8882	0.365	0.475	0.7437

TABLE 8: Southeast Sumatra Field  
Calculation of Recovery, Stiles' Method

(1) h Fract. of Cum. Thickness	(2) $K^1$ Dimensionless Permeability	(3) C Cum. Capacity Fraction	(4) $K^1 h$	(5) $K^1 h + (1-C)$	(6) Rec. Fract. of Total (5)/(2)
0.588	0.53	0.8973	0.312	0.414	0.7820
0.605	0.53	0.9064	0.321	0.414	0.7820
0.623	0.53	0.9155	0.330	0.414	0.7820
0.640	0.49	0.9240	0.314	0.389	0.7938
0.657	0.45	0.9318	0.296	0.363	0.8066
0.674	0.42	0.9390	0.283	0.343	0.8166
0.693	0.38	0.9485	0.263	0.317	0.8342
0.711	0.37	0.9519	0.263	0.310	0.8378
0.728	0.32	0.9574	0.233	0.275	0.8593
0.745	0.30	0.9626	0.223	0.260	0.8666
0.762	0.29	0.9676	0.221	0.252	0.8689
0.780	0.29	0.9726	0.220	0.253	0.8724
0.797	0.25	0.9770	0.199	0.221	0.8840
0.814	0.24	0.9811	0.195	0.213	0.8875
0.831	0.18	0.9843	0.150	0.165	0.9166
0.849	0.13	0.9866	0.110	0.122	0.9384
0.862	0.11	0.9884	0.095	0.106	0.9636
0.880	0.10	0.9901	0.088	0.097	0.9700
0.896	0.10	0.9918	0.090	0.097	0.9700
0.914	0.09	0.9933	0.082	0.088	0.9777
0.931	0.09	0.9948	0.084	0.088	0.9777
0.948	0.08	0.9962	0.076	0.079	0.9875
0.965	0.08	0.9976	0.077	0.079	0.9875
0.983	0.06	0.9985	0.059	0.058	0.9900
1.000	0.045	1.000	0.045	0.045	1.000

TABLE 8: Continued

(1) h Fract. of Cum. Thickness	(2) C Cum. Capacity Fraction	(3) CA	(4) CA + (1-C)	(5) Watercut Fraction (3)/(4)
0.017	0.093	0.100	1.007	0.0993
0.034	0.174	0.188	1.014	0.1854
0.052	0.220	0.237	1.017	0.2330
0.069	0.264	0.285	1.019	0.2797
0.086	0.305	0.329*	1.024	0.3213
0.103	0.341	0.368	1.027	0.3583
0.121	0.376	0.406	1.030	0.3942
0.138	0.410	0.443	1.033	0.4288
0.155	0.440	0.475	1.035	0.4589
0.172	0.471	0.509	1.038	0.4904
0.190	0.498	0.538	1.040	0.5173
0.207	0.525	0.567	1.042	0.5441
0.224	0.547	0.590	1.043	0.5657
0.241	0.570	0.616	1.046	0.5890
0.259	0.591	0.638	1.047	0.6093
0.272	0.612	0.661	1.049	0.6350
0.289	0.633	0.684	1.051	0.6508
0.306	0.653	0.705	1.052	0.6701
0.324	0.672	0.725	1.053	0.6885
0.342	0.692	0.747	1.055	0.7080
0.360	0.711	0.768	1.057	0.7266
0.376	0.728	0.786	1.058	0.7430
0.393	0.746	0.806	1.060	0.7603
0.411	0.763	0.824	1.061	0.7766
0.428	0.780	0.842	1.062	0.7928
0.445	0.796	0.860	1.064	0.8083
0.462	0.813	0.878	1.065	0.8244
0.480	0.827	0.893	1.066	0.8377
0.497	0.841	0.908	1.067	0.8510
0.520	0.854	0.922	1.068	0.8633
0.537	0.867	0.936	1.069	0.8756
0.554	0.878	0.948	1.070	0.8859
0.571	0.890	0.961	1.071	0.8973

TABLE 9: Southeast Sumatra Field  
Calculation of Water Cut  
Stiles' Method

(1) h Fract. of Cum. Thickness	(2) C Cum. Capacity Fraction	(3) CA —	(4) CA + (1-C) —	(5) Watercut Fraction (3)/(4)
0.588	0.898	0.970	1.072	0.9048
0.605	0.907	0.979	1.072	0.9132
0.623	0.916	0.989	1.073	0.9217
0.640	0.925	0.999	1.074	0.9301
0.657	0.933	1.010	1.077	0.9378
0.674	0.940	1.015	1.075	0.9415
0.693	0.946	1.021	1.075	0.9497
0.711	0.953	1.030	1.077	0.9564
0.728	0.958	1.035	1.077	0.9610
0.745	0.963	1.040	1.077	0.9656
0.762	0.969	1.046	1.077	0.9712
0.780	0.973	1.051	1.078	0.9749
0.797	0.978	1.056	1.078	0.9796
0.814	0.982	1.060	1.078	0.9833
0.831	0.985	1.064	1.079	0.9860
0.849	0.988	1.067	1.079	0.9888
0.862	0.989	1.068	1.079	0.9898
0.880	0.991	1.070	1.079	0.9916
0.896	0.993	1.072	1.079	0.9935
0.914	0.994	1.073	1.079	0.9944
0.931	0.996	1.075	1.079	0.9963
0.948	0.997	1.076	1.079	0.9972
0.965	0.998	1.077	1.079	0.9981
0.983	0.999	1.078	1.079	0.9990
1.000	1.000	1.080	1.080	1.0000

TABLE 9: Continued

(1) Cum. Oil Recov. Fract. of Total	(2) Oil Recov. Bbls $(1)_n - (1)_{n-1}$ x T.R.O.	(3) Cum. Oil Recov. Bbls $\Sigma (2)$	(4) Watercut Fract.	(5) Avg. Watercut Fract. $\frac{(4)_n + (4)_{n-1}}{2}$
0	0	0	0	0
0.0182	66250	66250	0.0993	0.0496
0.1000	297750	364000	0.1320	0.1156
0.1500	182000	546000	0.1570	0.1445
0.2000	182000	728000	0.1790	0.1680
0.2500	182000	910000	0.1960	0.1875
0.3000	182000	1092000	0.2160	0.2060
0.3500	182000	1274000	0.2500	0.2330
0.4000	182000	1456000	0.3400	0.2950
0.4500	182000	1638000	0.4300	0.3850
0.5000	182000	1820000	0.5000	0.1650
0.5500	182000	2002000	0.5500	0.5250
0.6000	182000	2184000	0.6450	0.5975
0.6300	108000	2292000	0.7100	0.6775
0.6500	74000	2366000	0.7800	0.7450
0.7000	182000	2548000	0.8460	0.8230
0.7500	182000	2730000	0.9000	0.8730
0.8000	182000	2912000	0.9300	0.9150
0.8500	182000	3094000	0.9500	0.9400

TABLE 10: Southeast Sumatra Field  
Waterflood Performance (M = 1)  
Stiles' Method

(6) Avg. Oil Prod. Rate 5000* [1 - (5)]	(7) Time To Produce Oil Recov. @ Avg. Prod. Rate days (2)/(6)	(8) Cum. Time After fill up $\Sigma(7)$	(9) Cum. Water Injected 4,080,000* + 5000 (8)
5000	0	0	4080000
4750	13.9	13.9	4149500
4420	67.3	81.2	4486000
4280	42.5	123.7	4698500
4160	43.7	167.4	4917000
4060	44.8	212.2	5143500
3970	45.8	258.0	5370000
3835	47.4	305.4	5607000
3525	51.6	357.0	5865000
3075	59.1	416.1	6160000
2675	68.0	484.1	6500500
2375	76.6	560.7	6883500
2012	90.4	651.1	7335500
1612	67.1	724.8	7704000
1275	57.0	781.8	7989000
885	205.0	986.8	9014000
635	786.4	1273.2	10446000
425	428.0	1701.2	12586000
290	627.0	2328.0	15720000

\* Water Injection Rate = 5,000 BWPD

\* Fill Up Volume =  $7758 \times Ah \times \phi \times S_g = 7758 \times 28667 \times 0.124 \times 0.148 = 4,080,000$  bbls

TABLE 10: Continued



(1) Year	(2) Gross Barrels (Second. and Primary Oil)	(3) Net Production (Barrels)	(4) Value - Net Production (Dollars)	(5) Well Operating Cost (Dollars)	(6) Plant Operating Cost (Dollars)
1970	42300	34368.7	94513.9	86400	54750
1971	33900	27543.8	75745.4	86400	54750
1972	651590	529416.9	1455896.5	97200	54750
1973	334000	271375.0	746281.2	97200	54750
1974	186800	151775.0	417381.2	97200	54750
1975	161200	130975.0	360181.2	97200	54750
1976	148600	120737.5	332028.0	97200	54750
1977	116500	94656.2	260304.4	92400	54750
1978	108300	87993.8	241983.0	87600	54750
1979	93900	76293.7	209807.5	87600	54750
1980	86070	69931.9	192312.6	77400	54750
1981	78200	63537.5	174728.2	73200	54750
1982	68400	55575.0	152831.3	68400	54750
1983	61640	50082.5	137727.0	58800	54750
1984	54200	44037.5	121103.0	49200	54750
1985	48600	39487.5	108590.6	39600	54750
Total	2274200	1847787.5	5081415.0	1293000	876000

Avg. Net Revenue Interest = 0.8125

Value of Oil = \$2.75/bbl

Operating Cost Per Producing Well Under Flood = \$400/month

Operating Cost Per Well Under Primary = \$350/month

Operating Cost Per Injection Well = \$150/month

Water Plant Operating Cost = 3¢ Per bbl of water injected

Production Taxes = 22¢ Per bbl of oil

Waterflood Investment = \$300,000

TABLE 11: Southeast Sumatra Field  
Waterflood Economic Evaluation

(7) Production Taxes (Dollars)	(8) Net Income (Dollars)	(9) 10% Discount Factor	(10) 20% Discount Factor	(11) Present Value Net Income Disc. @ 10% (Dollars)	(12) Present Value Net Income Disc. @ 20% (Dollars)
7561.1	-54197.2	0.9091	0.8333	-49270.7	-45162.5
6059.6	-71464.2	0.8264	0.6944	-59057.9	-49624.7
116471.7	1187474.8	0.7513	0.5787	892149.8	687191.7
59702.50	534628.7	0.6830	0.4823	365151.4	257851.4
33390.50	232040.7	0.6209	0.4019	144074.1	93257.2
28814.40	179416.8	0.5645	0.3349	101280.8	60086.7
26562.3	153515.7	0.5132	0.2791	78784.2	42846.2
20824.3	92330.1	0.4665	0.2326	43072.0	21476.0
19358.5	80274.5	0.4241	0.1938	34044.4	15557.2
16784.4	50673.1	0.3855	0.1615	19534.5	8183.7
15385.0	44777.6	0.3505	0.1346	15694.5	6027.0
13978.3	32799.9	0.3186	0.1122	10450.1	3680.2
12226.5	17454.8	0.2897	0.0935	5056.7	1632.0
11018.4	13158.6	0.2633	0.0779	3464.6	1025.1
9688.3	7464.7	0.2394	0.0649	1787.1	484.4
8687.2	5553.4	0.2176	0.0541	1208.4	300.4
406513.	2505902.			1607424.0	1104812.0

TABLE 11: Continued

(13) Capitol Investment (Dollars)	(14) Present Value Capitol Invest. Disc. @ 10% (Dollars)	(15) Discounted Profit (Dollars)	(16) Cum. Discounted Profit @ 10% (Dollars)	(17) Cum. Discounted Profit @ 20% (Dollars)
300000	272730	-322000.7 -59057.9 892149.8 365151.4 144074.1 101280.8 78784.2 43072.0 34044.4 19534.5 15694.5 10450.1 5056.7 3464.6 1787.1 1208.4	-322000.7 -381058.6 511091.2 876242.6 1020316.7 1121597.5 1200381.7 1243453.7 1277498.1 1297032.6 1312727.1 1323177.2 1328233.9 1331698.5 1333485.6 1334694.0	-295152.5 -344777.2 342414.5 600265.9 693523.1 753609.8 796456.0 817932.0 833489.2 841672.9 847699.9 851380.1 853012.1 854037.2 854521.6 854822.0
300000	272730	1334694.0		

TABLE 11: Continued

(1) Year	(2) Gross Barrels (Second. and Primary Oil)	(3) Net Production (Barrels)	(4) Value - Net Production (Dollars)	(5) Well Operating Cost (Dollars)	(6) Plant Operating Cost (Dollars)
1970	42300	34368.7	94513.9	86400	54750
1971	33900	27543.8	75745.4	86400	54750
1972	1163470	945319.4	2599678.3	97200	54750
1973	567360	460980.0	1267695.0	97200	54750
1974	358400	291200.0	800800.0	97200	54750
1975	209540	170251.3	468191.1	97200	54750
1976	172770	140375.6	386032.7	87600	54750
1977	134770	109500.7	301126.7	82800	54750
1978	116250	94453.1	259746.0	77400	54750
1979	95800	77837.6	214053.4	73200	54750
1980	83580	67908.8	186749.2	68400	54750
1981	69360	56355.0	154976.7	58800	54750
1982	57300	46556.0	128029.0	49200	54750
1983	<u>31400</u>	<u>25512.5</u>	<u>701590.4</u>	<u>26400</u>	<u>36555</u>
Total	3136200	2548162.5	7007446.8	1085400	748305

A = Waterflood Investment = \$300,000

B = Cost of 301,200 lb. of Polymer @ \$1.60/lb. = \$481,920

C = Rental Cost of Equipment for Polymer Injection = \$10,080

Polymer Flood Investment = A + B + C = \$792,000

TABLE 12: Southeast Sumatra Field  
Polymerflood Economic Evaluation

(7) Production Taxes (Dollars)	(8) Net Income (Dollars)	(9) 10% Discount Factor	(10) 20% Discount Factor	(11) Present Value Net Income Disc. @ 10% (Dollars)	(12) Present Value Net Income Disc. @ 20% (Dollars)
7561.1	- 54197.2	0.9091	0.8333	- 49270.7	- 45162.5
6059.6	- 71464.2	0.8264	0.6944	- 59057.9	- 49624.7
207970.3	2239708.0	0.7513	0.5787	1682692.6	1296119.0
101415.6	1014329.4	0.6830	0.4823	692787.0	489211.0
64064.0	584786.0	0.6209	0.4019	363093.6	235025.5
37455.3	278785.8	0.5645	0.3349	157374.6	93365.4
30882.6	212800.1	0.5132	0.2791	109209.0	59392.50
24090.2	139486.5	0.4665	0.2326	65070.5	32444.5
20779.7	106816.3	0.4241	0.1938	45300.8	20701.0
17124.3	68979.1	0.3855	0.1615	26591.4	11140.0
14940.0	48659.2	0.3505	0.1346	17055.0	6549.5
12398.1	29028.6	0.3186	0.1122	9248.5	3257.0
10242.3	13836.7	0.2897	0.0935	4008.5	1293.7
5612.7	1591.7	0.2633	0.0779	419.1	124.0
560595.8	4613146.0			3064522.0	2153836.0

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TABLE 12: Continued

(13) Capitol Investment (Dollars)	(14) Present Value Capitol Invest. Disc. @ 10% (Dollars)	(15) Discounted Profit (Dollars)	(16) Cum. Discounted Profit @ 10% (Dollars)	(17) Cum. Discounted Profit @ 20% (Dollars)
464000	421822.4	-471093.1	-471093.1	-431813.7
164000	135529.4	-194587.5	-665680.6	-595320.0
164000	123213.2	1559479.4	893798.8	605891.8
		692787.0	1586585.8	1095102.8
		363093.6	1949679.4	1330128.3
		157374.6	2107054.0	1423493.7
		109209.0	2216263.0	1482886.2
		65070.6	2281333.6	1515330.7
		45300.8	2326634.4	1536031.7
		26591.5	2353225.9	1547171.8
		17055.0	2370280.9	1553721.3
		9248.5	2379529.4	1556978.3
		4008.5	2383537.9	1558272.0
		419.1	2383957.0	1558396.0
792000	680565.0	2383957.0		

TABLE 12: Continued

(1) Year	(2) Gross Barrels	(3) Net Production (Barrels)	(4) Value - Net Production (Dollars)	(5) Well Operating Cost (Dollars)
1970	0	0	0	0
1971	0	0	0	0
1972	511880	415902.5	1143731.8	0
1973	233360	189605.0	521413.8	0
1974	171600	139425.0	383418.8	0
1975	48340	39276.3	108009.9	0
1976	24170	19638.1	54004.7	-9600
1977	18270	14844.5	40822.3	-9600
1978	7950	6459.3	17763.0	-10200
1979	1900	1543.9	4245.9	-14400
1980	-2490	-2023.1	-5563.4	-9000
1981	-8840	-7182.5	-19751.5	-14400
1982	-11100	-9019.0	-24802.3	-19200
1983	-30240	-24570.0	-67567.6	-32400
1984	-54200	-44037.5	-121103.0	-49200
1985	<u>-48600</u>	<u>-39487.5</u>	<u>-108590.6</u>	<u>-39600</u>
Total	862000	700375.	1926031.8	-207600

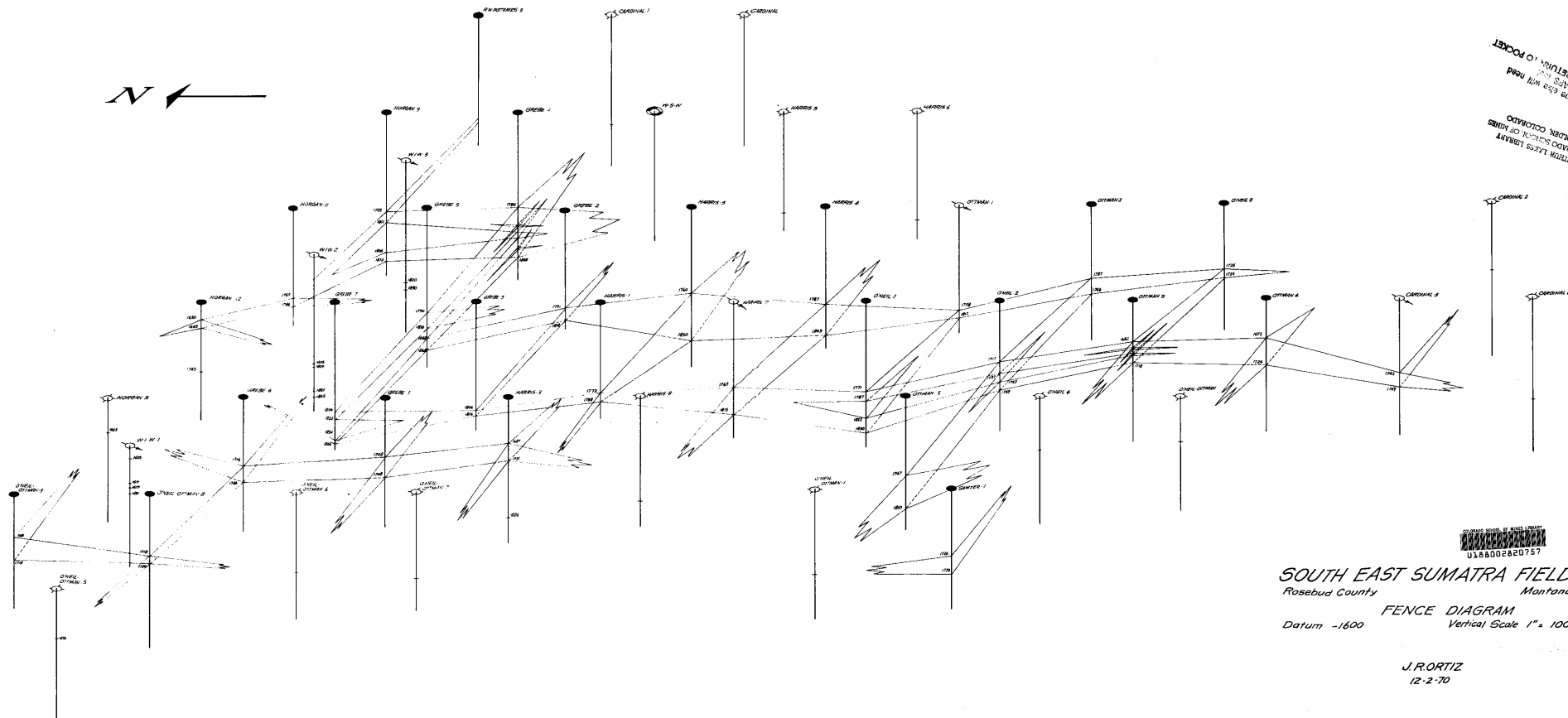
TABLE 13: Southeast Sumatra Field  
Economic Evaluation of Polymerflood - Waterflood

(6) Plant Operating Cost (Dollars)	(7) Production Taxes (Dollars)	(8) Net Income (Dollars)	(9) Present Value Net Income Disc. @ 10% (Dollars)	(10) Present Value Net Income Disc. @ 20% (Dollars)
0	0	0	0	0
0	0	0	0	0
0	91498.6	1052233.2	790542.8	608927.3
0	41713.1	479700.7	327635.6	231359.6
0	30673.5	352745.3	219019.5	141768.3
0	8640.9	99369.0	56093.8	33278.7
0	4320.3	59284.4	30424.8	16546.3
0	3265.9	47156.4	21998.5	10968.5
0	1421.2	26541.8	11256.4	5143.8
0	339.9	18306.0	7056.9	2956.4
0	-445.0	3881.6	1360.5	522.5
0	-1380.2	-3771.3	-1201.6	-423.2
0	-2184.2	-3618.1	-1048.2	-338.3
-18195	-5405.7	-11566.9	-3045.5	-901.1
-54750	-9688.3	-7464.7	-1787.1	-484.4
<u>-54750</u>	<u>-8687.2</u>	<u>-5553.4</u>	<u>-1208.4</u>	<u>-300.4</u>
-127695	154082.8	2110244.0	1457098.0	1049024.

TABLE 13: Continued

(11) Capitol Invest. (Dollars)	(12) Present Value Capital Invest. Disc. @ 10% (Dollars)	(13) Discounted Profit (Dollars)	(14) Cum. Disc. Profit @ 10% (Dollars)	(15) Cum. Disc. Profit @ 20% (Dollars)
164000	149092.4	-149092.4	-149092.4	-136661.2
164000	135529.4	-135529.4	-284622.0	-250542.8
164000	123213.2	667329.6	382707.6	263477.3
		327635.6	710343.2	494836.9
		219019.5	929362.7	636605.2
		56093.8	985456.5	669883.9
		30424.8	1015881.3	686430.2
		21998.5	1037879.9	697398.7
		11256.4	1049136.3	702542.5
		7056.9	1056193.3	705498.9
		1360.5	1057553.8	706021.4
		-1201.6	1056352.2	705598.2
		-1048.2	1055304.0	705259.9
		-3045.5	1052258.5	704358.8
		-1787.1	1050471.4	703876.4
		-1208.4	1049263.0	703574.0
492000	407835.0	1049263.0		

TABLE 13: Continued



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**SOUTH EAST SUMATRA FIELD**  
Rosebud County Montana

**FENCE DIAGRAM**  
Datum -1600 Vertical Scale 1" = 100'

J.R.ORTIZ  
12-2-70

MAP 1