statoil

PORE PRESSURE AND FRACTURE GRADIENT ESTIMATES
FOR WELL 1/9-1 AND WELL 1/9-2

PORE PRESSURE GRADIENT PREDICTIONS
FOR WELL 1/9-3 AND WELL 1/9-Y

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Den norske stats oljeselskap a.s

CONTENTS

1. Abstract

Pore pressure gradients have been estimated for wells 1/9-1 and 1/9-2 by the use of sonic, density and conductivity logs. Based upon these estimates pore pressure gradient predictions for wells 1/9-3, 1/9-γ have been done.

Fracture gradients have also been calculated for wells 1/9-1 and 1/9-2 by the use of estimated overburden and pore pressure gradients.

2. HYDROSTATIC GRADIENT

It is not possible to calculate the formation water salinity from the SP-curve in Miocene down to Paleocene in wells 1/9-1 and 1/9-2.

The lack of good sand zones without gas makes it also difficult to calculate salinity from resistivity and porosity logs.

From the conductivity plots an increase in salinity can be seen from about 2000 m in Oligocene. The salinity increases with depth down to Paleocene.

In Maastrichtian the salinity is about 70000 ppm (1.02 g/cc at 240^{O} F and 7000 psig). Further up in the wells it is not believed that the hydrostatic gradient is far from this gradient taking into account fresher formation water and decreasing pressure and temperature towards the upper parts of the wells.

An average hydrostatic gradient of 1.02 g/cc has been used in the pressure estimates.

3. OVERBURDEN GRADIENT

Figure 1. shows the integrated FDC-log versus depth for wells 1/9-1, 1/9-2, 30/19-2 (UK) and wells from the Ekofisk area.

The FDC- log for 1/9-1 is affected by gas in the interval 1000-2000 m and gives lower overburden than is expected to be met in wells 1/9-3 and 1/9-γ.

The overburden gradient used is about the same as for wells 1/9-2 and 30/19-2 above 1000 m approaching the overburden gradient for the Ekofisk area below 1000 m.

4. PORE PRESSURE GRADIENTS

Two methods have been used to calculate pore pressure from sonic and density logs. (see Appendix A)

1. The Equivalent Depth Method.
2. The Compaction Expont Method

An attempt has been made to establish normal pressure trend lines on a conductivity plots and to calculate pore pressure from Compaction Exponent Method.
Clay porosity has been plotted versus depth and a clay porosity pore pressure gradient relationship has been made.

4.1 PORE PRESSURE ESTIMATES FROM SONIC LOG

A straight normal trend line was drawn through the normal pressured parts in the wells 1/9-1, 1/9-2. (Fig. 3 and 4) The above mentioned two methods was used to calculate pore pressure (fig. 14 and 21). The Compaction Exponent Method gives too low pressures in the upper parts of the overpressured zone and too high pressures in the lower parts. This is most probably due to the use of a straight trend line which gives too low normal log values in the upper overpressured parts of the wells and too high values in the lower parts.

The Equivalent Depth Method gives the best estimates of Pore Pressure gradients when using straight trend lines.

4.2 PORE PRESSURE ESTIMATES FROM DENSITY LOG

The FDC logs were plotted on lin-lin grids and a straight trend line was drawn through normal pressured regions in wells 1/9-1 and 1/9-2.

The Compaction Exponent Method was used with an exponent equal to 10. The two methods did not give the same gradients in Miocene and a normal trend shift for Miocene was established. The resulting pore pressure gradients are shown in fig. 15 and 22.

4.3 PORE PRESSURE ESTIMATES FROM CONDUCTIVITY LOG

An attempt was made to establish some normal trend lines on the conductivity plot so that the pore pressures calculated from the Compaction Exponent Method with an exponent equal to 1.2 would give a good fit to pressures calculated from sonic and density logs. A formation water salinity change in the middle of Oligocene gives a trend line shift. The new trend indicates that the normal conductivity should increase with depth. This is not what normaly is expected and the reason is an increasing formation salinity with depth below 2000 m.

The resulting pore pressure gradients can be seen in fig. 16 and 23.

4.4 PORE PRESSURE ESTIMATES FROM CLAY POROSITY

Clay porosity (Φ clay) was calculated from sonic and density logs and plotted versus depth. The shales are believed to consist of a mixture of sand, clay and water. The log respons in dry sand and clay was selected to be:

ρb_{sand} = 2.65 g/cc Δt sand = 55.5 µs/ft

ρb_{clay} = 2.85 g/cc Δt clay = 140 µs/ft

The respons in formation water:

ρb_{water} = 1.02 g/cc Δt water = 189 µs/ft

The quantitative calculation of sand and clay fractions and the clay porosity are not believed to be very reliable. The relative changes will be most important in the pore pressure calculations.

The clay porosity plotted versus depth for 1/9-1 and 1/9-2 can be seen on fig. 9 and 10. The plot for 1/9-2 seems to be fairly good but the plot for 1/9-1 are influenced by the gas effect on log responses. The correlation of the 1/9-2 plot with sonic and density plot and also the D_c-exponent is good. A straight normal trend line was drawn through the regions which are believed to be normal pressured. A relationship between the pore pressure gradient and Φclay/Φclay normal was then established based on the pore pressures calculated from sonic and density logs. This relationship can be seen in fig. 17. The calculated pore pressure gradients can be seen in fig. 18 and 24.

4.5 CONCLUSION PORE PRESSURE GRADIENT ESTIMATES

The estimated pore pressure gradients for well 1/9-1 and well 1/9-2 are shown in fig. 13 and 20. They are based upon the calculations from sonic and density logs using the Equivalent Depth Method.

The quantitative pore pressure estimates above 1000 m are more uncertain in both wells due to the greater scattering in the data. The clay porosity indicates overpressure in well 1/9-1 but not in 1/9-2 above 1000 m. All the other logs indicate overpressure above 1000 m. The estimated pore pressure gradient seems to increase more rapidly up to maximum pressure gradient than reflected in the mud weights used. (fig. 12 and 19), which may indicate that parts of the two wells are drilled underbalanced. On the other hand, the maximum mud weight used on well 1/9-2 seems to be slightly too high.

5. FRACTURE GRADIENT ESTIMATES

The fracture gradients for wells 1/9-1 and 1/9-2 are calculated by using two methods (see Appendix B):

1. Eaton & Pennebaker
2. Andersen, Ingram & Zanier.

In method 2 the shale porosity used in the formula was calculated from the sonic-density crossplot using the same matrix and fluid responses as given in 4.4. In fig. 25 and 26 the results from the calculations are presented using different but constant Poissons ratios. The discreapancy is big in normal pressured zones because method 1 is primarly depending upon the Pore Pressure gradient while method 2 are more depending upon the overburden gradient.

A variable Poissons ratio with depth (see fig. 27) will give a better fit between the two methods. Method 1 reflects the lower fracture gradients in normal pressured zones much more than method 2.

It should be emphasized that the fracture gradients in these calculations relates to silty or sandy formation or a relatively weak formation with high quarts content. Shales with low quartz content have higher fracture gradients, and act more elastic than silty or sandy zones.

From the pore pressure estimate an abrupt decrease in pore pressure is seen in Lower Eocene and in Paleocene.

From a calculation of quartz, clay and porosity content (see fig. 29) Well 1/9-2, intervall 2700 m - 2900 m, it can be seen that a relatively high quartz and low clay mineral content is seen were the 9 5/8" csg shoe landed (2856 m). In well 1/9-2 a lost return problem could probably have been avoided if the casing shoe had been set above 2800 m where the pore pressure gradient is higher, and the formation has a higher fracture gradient. The fracture gradient calculations indicates that the fracture gradients further into Paleocene are lower than measured from leak offs at the 9 5/8" csg shoe in wells 1/9-1 and 1/9-2, (1.84 g/cc) because the pore pressure still decreases when drilling into Paleocene.

5.1 CONCLUSION ON FRACTURE GRADIENT ESTIMATES

The calculated fracture gradients for wells 1/9-1 and 1/9-2 indicates approximately the strength of silt or sand formations with the same pore pressures calculated for the two wells.

The fracture gradients should be considered to be a qualitative indication of how the fracturing strength changes with overburden and pore pressure in such weak formations, more than to be a quantitative estimate of the fracture gradients for the two wells.

6. Pore pressure prediction, well 1/9-3

The pore pressure expected to be met in well 1/9-3 is shown in fig. 30. The estimate is based upon the pressures calculated for wells 1/9-1 and 1/9-2 and adjusted according to stratigraphic depth prognosis.

Two bright spots on the seismic indicate possible gas at 560 m and 1760 m. The mud weight should be increased to 1.3 g/cc when drilling out the 20" csg.

The rapid pore pressure gradient build up calculated in well 1/9-1 and 1/9-2 indicates that mud weight should be increased to 1.8 at 1500 m and increased to 1.82 - 1.83 at 1800-1900 m.

The pore pressure decrease in Lower Eocene is expected at 2760 m. The 13 3/8" csg should be landed above 2760 m in the higher pore pressure gradient zone to avoid lost circulation problems.

A pressure gradient increase should be expected in Lower Cretaceous (1.7-1.75g/cc) and Jurassic (1.75-1.85g/cc) based upon experience from wells drilled to Jurassic in the Eldfisk and Valhall field.

Care should be taken not to increase the mudweight above 1.75 - 1.78 g/cc before setting casing in Lower Cretaceous due to the weak zones in Lower Eocene, Paleocene.

7. Pore Pressure prediction 1/9-γ

The pore pressure gradient expected to be met in well 1/9-γ is shown in fig. 31. The pressure estimate is based upon the pressures in wells 1/9-1 and 1/9-2, and adjusted according to stratigraphic depth prognosis.

Bright spots on the seismic, indicating possible gas, is seen in the intervals 1100 m - 1300 m and 1630m - 2100 m.

Rapid pore pressure build up below the pressure transition zone means that mud weight should be increased to 1.8 g/cc before 1500 m and then gradually increased to 1.82 - 1.83 g/cc.

The 9 5/8" csg should not be landed much lower than the stratigraphic prognosis showing Top Lower Eocene (2635 m) to avoid lost cirkulation problems.

Again a pore pressure gradient increase should be expected when drilling into Lower Cretaceous and Jurassic.

8. Conclusion

From the pore pressure gradient estimates it seems that the mud weight should be increased to 1.3 g/cc below the 20" csg when drilling out 13 3/8" csg.(or 16" csg. in 1/9-3) mud weight should be increased relatively fast to 1.8 g/cc and then gradually increased to 1.82 - 1.83 g/cc.

Pore pressure gradients of 1.7 g/cc up to 1.75 g/cc is expected in Lower Cretaceous and 1.75 g/cc up to 1.85 g/cc in Jurassic.

The fracture gradient calculations show weak zones in Lower Eocene and Paleocene. Casing should be set before drilling into these weak zones about the Top of Lower Eocene.

9. APPENDIX A

Pore pressure gradient calculations are based upon the following two methods:

1. The Equivalent Depth Method

$$PP = PO - (PO-PN)\ D_E/D_I$$

PP	=	Pore pressure gradient (g/cc)
PO	=	Overburden gradient (g/cc)
PN	=	Hydrostatic gradient (g/cc)
D_E	=	Equivalent Depth (m)
D_I	=	Depth of interest (m)

2. The Compaction Exponent Method

$$PP = PO - (PO-PN)\ (LN/L)^{EXP}$$

LN	=	Normal log respons in shales
L	=	Log respons in shales
EXP	=	Exponent depending on the log used
EXP	=	3 for the sonic log
EXP	=	10 for the density log
EXP	=	1.2 for the conductivity log

10. APPENDIX B

Fracture gradients was estimated using two different methods.

1. Eaton & Pennebaker

$$PFT = \frac{\mu}{1-\mu} (PO-PP) + PP$$

where

PF = Fracture gradient (g/cc)

PO = Overburden gradient (g/cc)

PP = Pore pressure gradient (g/cc)

μ = Poissons ratio

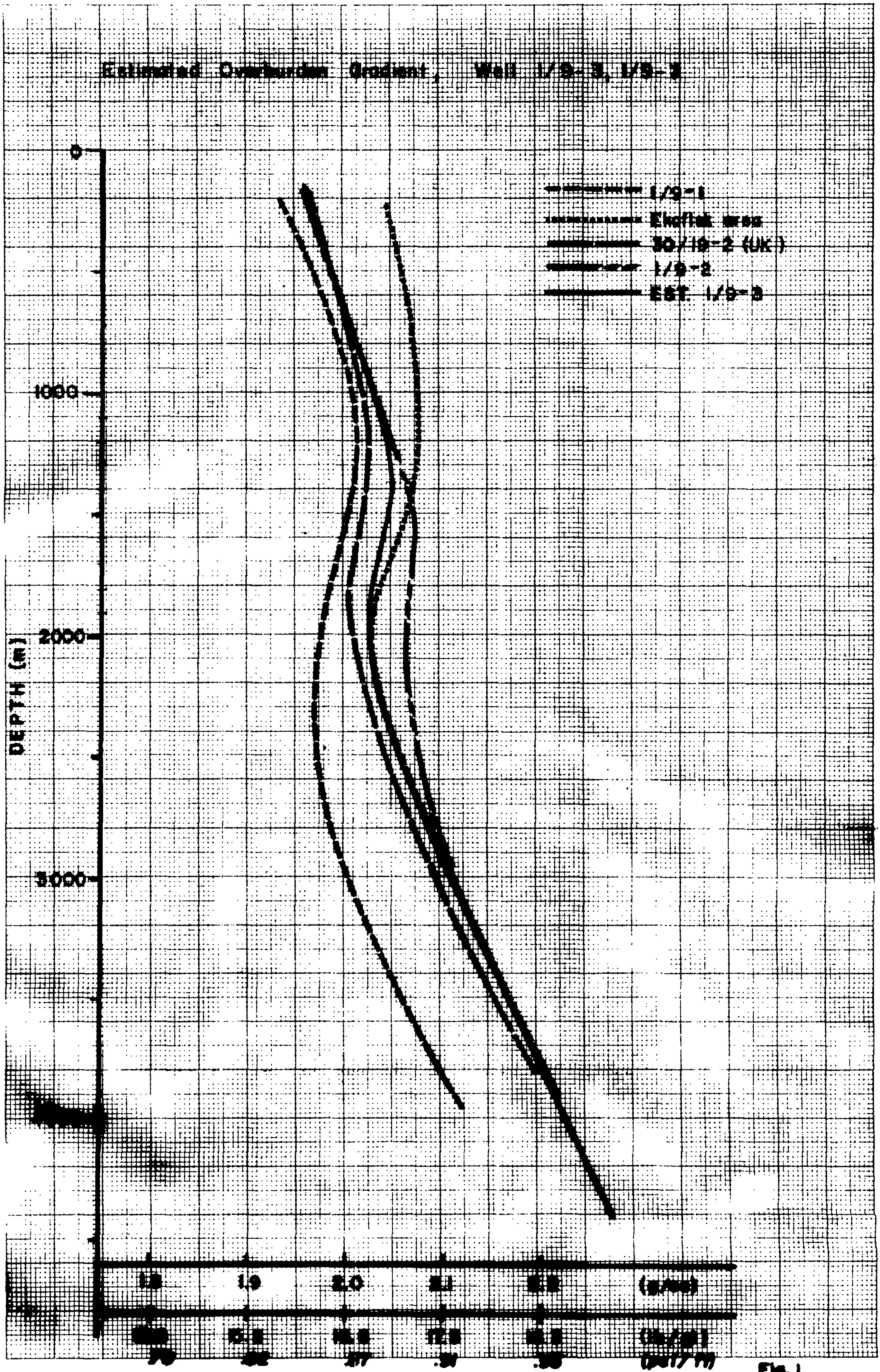
2. Andersen, Ingram & Zanier

$$PF = \frac{2\mu}{1-\mu} PO + \alpha \frac{1-3\mu}{1-\mu} \cdot PP$$

where

α = $1 - (1 - \Phi)$

Φ = porosity in shales calculated from density and sonic log



Estimated Overburden Gradient, Well 1/9-3
1/9-1
Ekofisk area
30/19-2 (UK)
1/9-2
EST. 1/9-3
0
1000
2000
3000
DEPTH (m)
1.9
2.0

Fig. 1

STRATIGRAPHIC PROGNOSIS

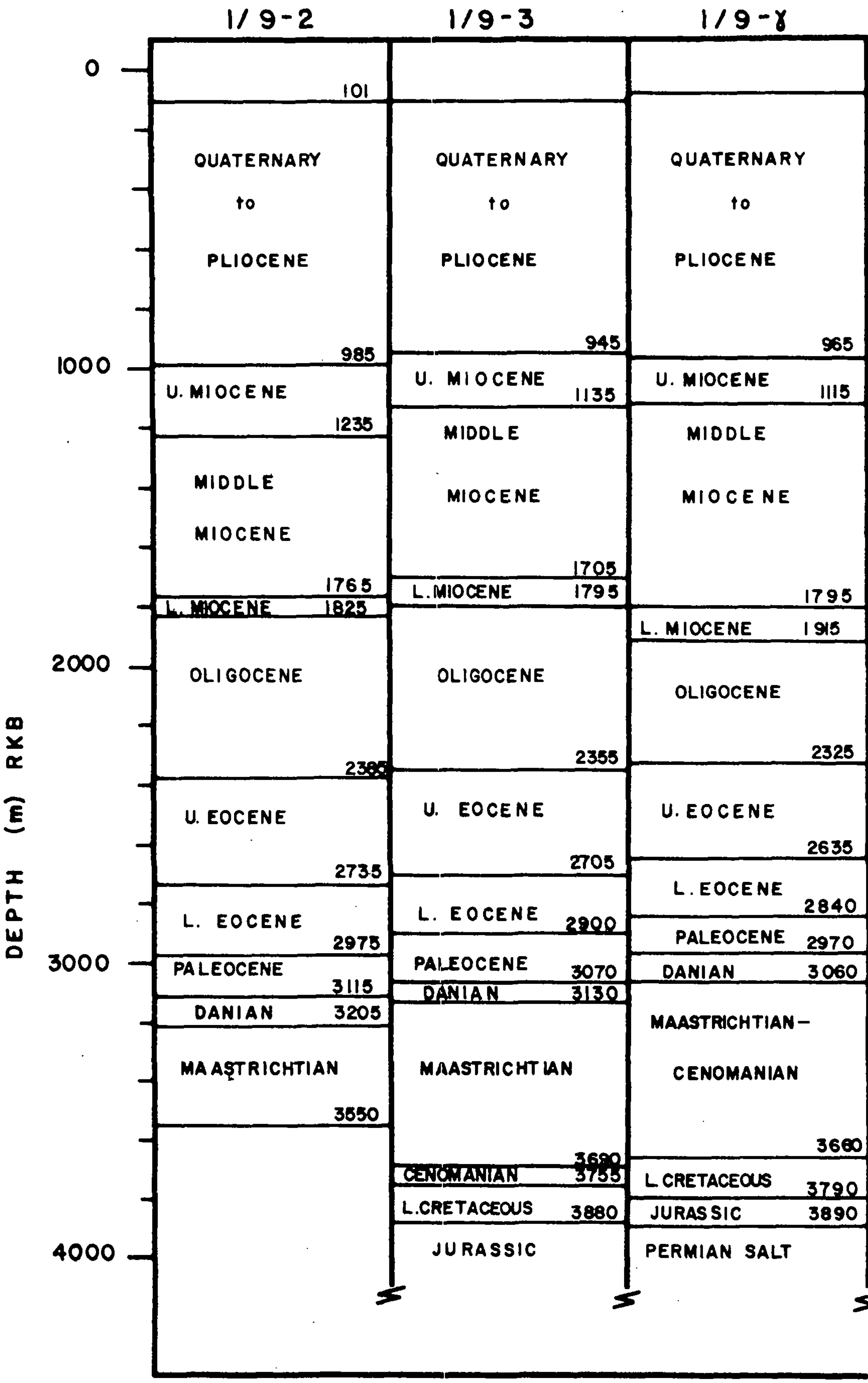


Fig. 2

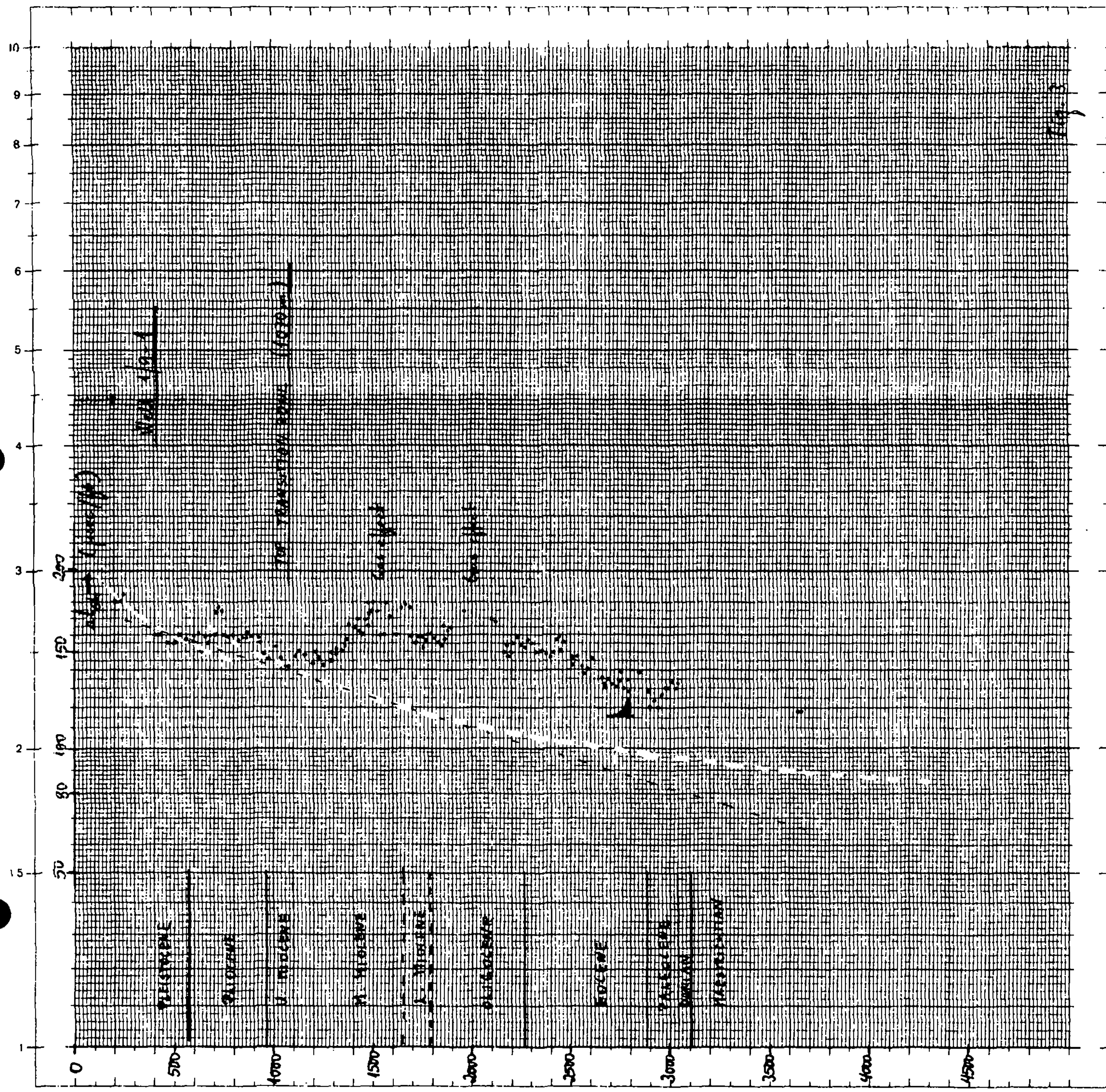
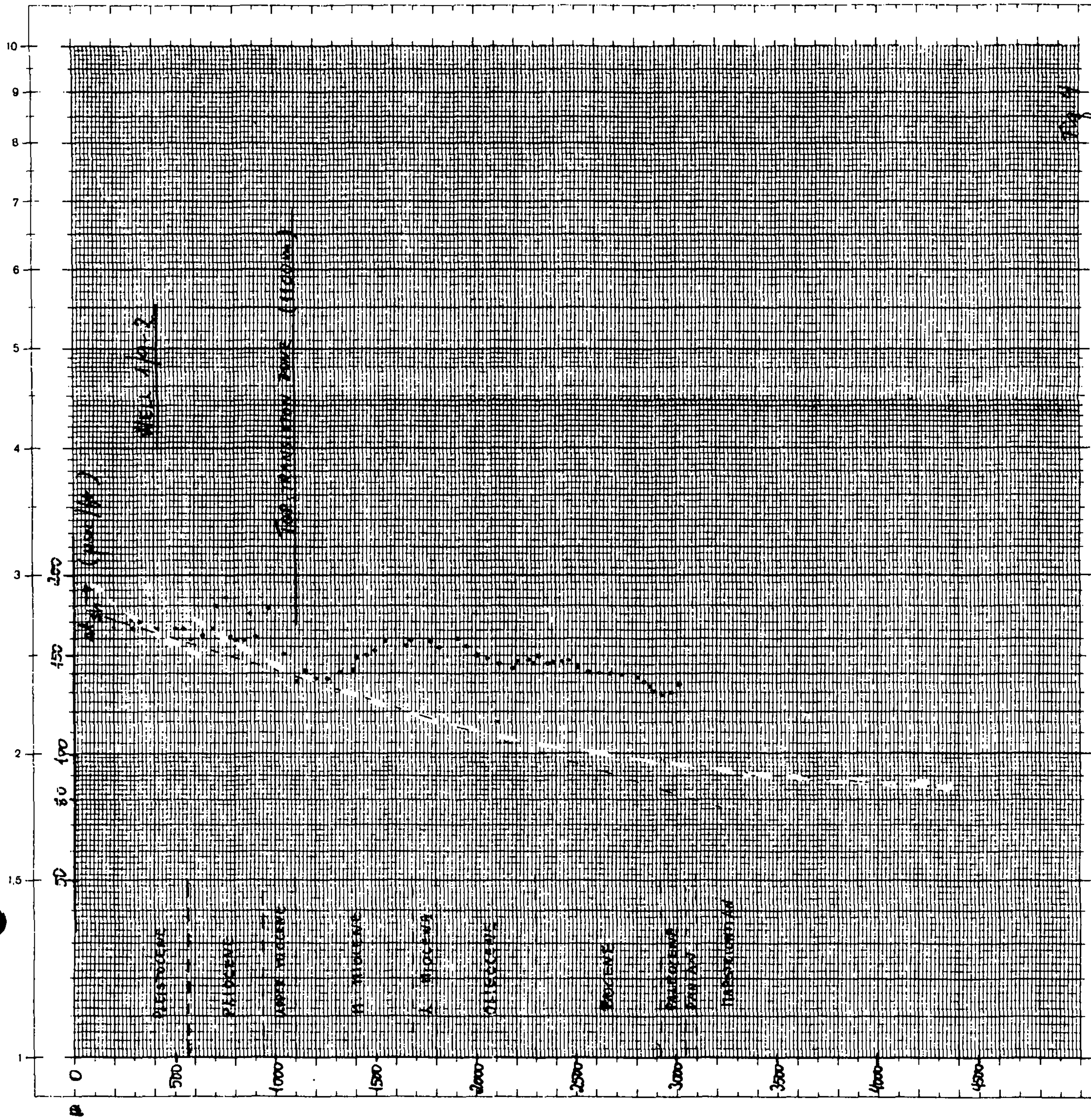
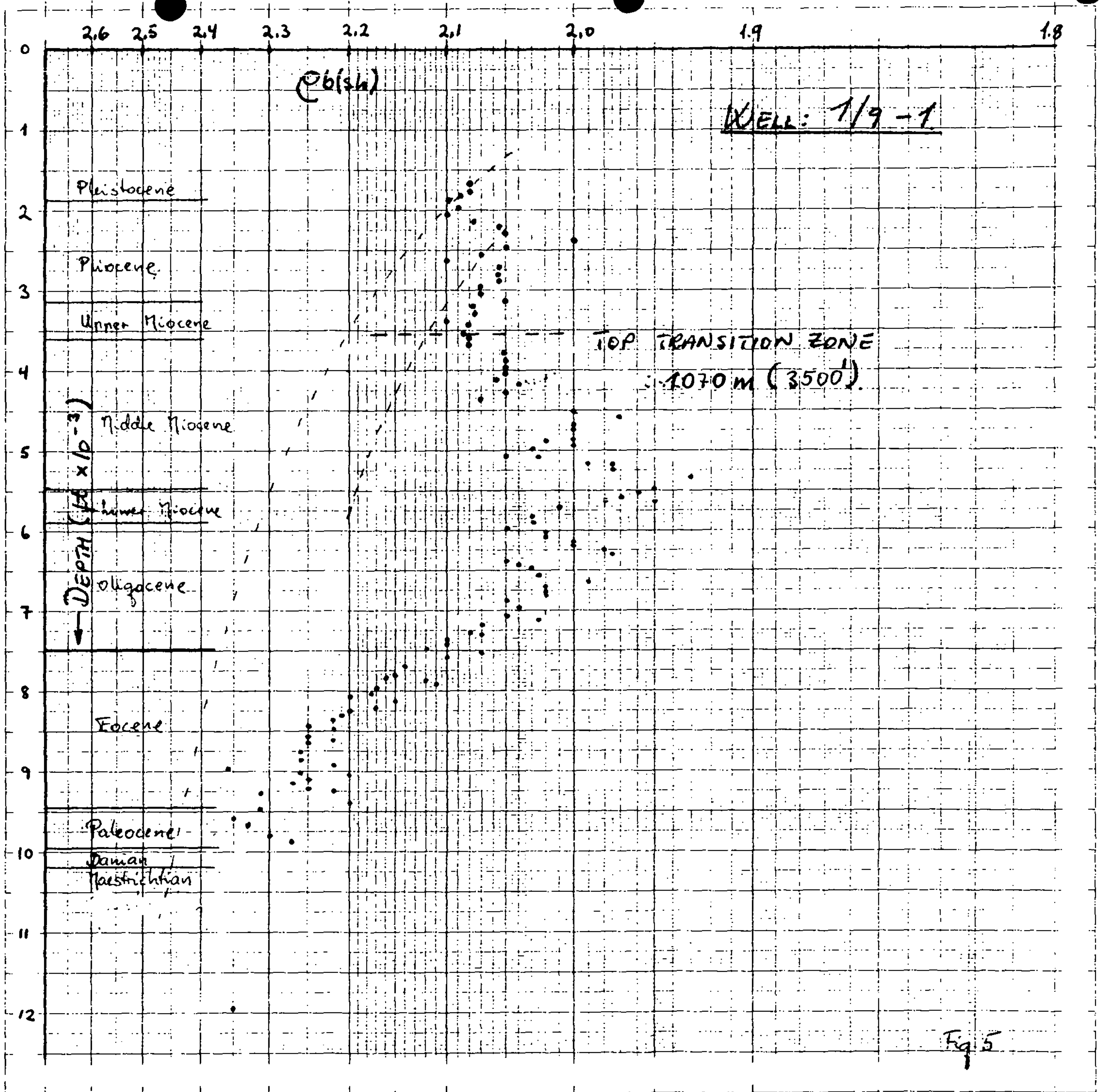
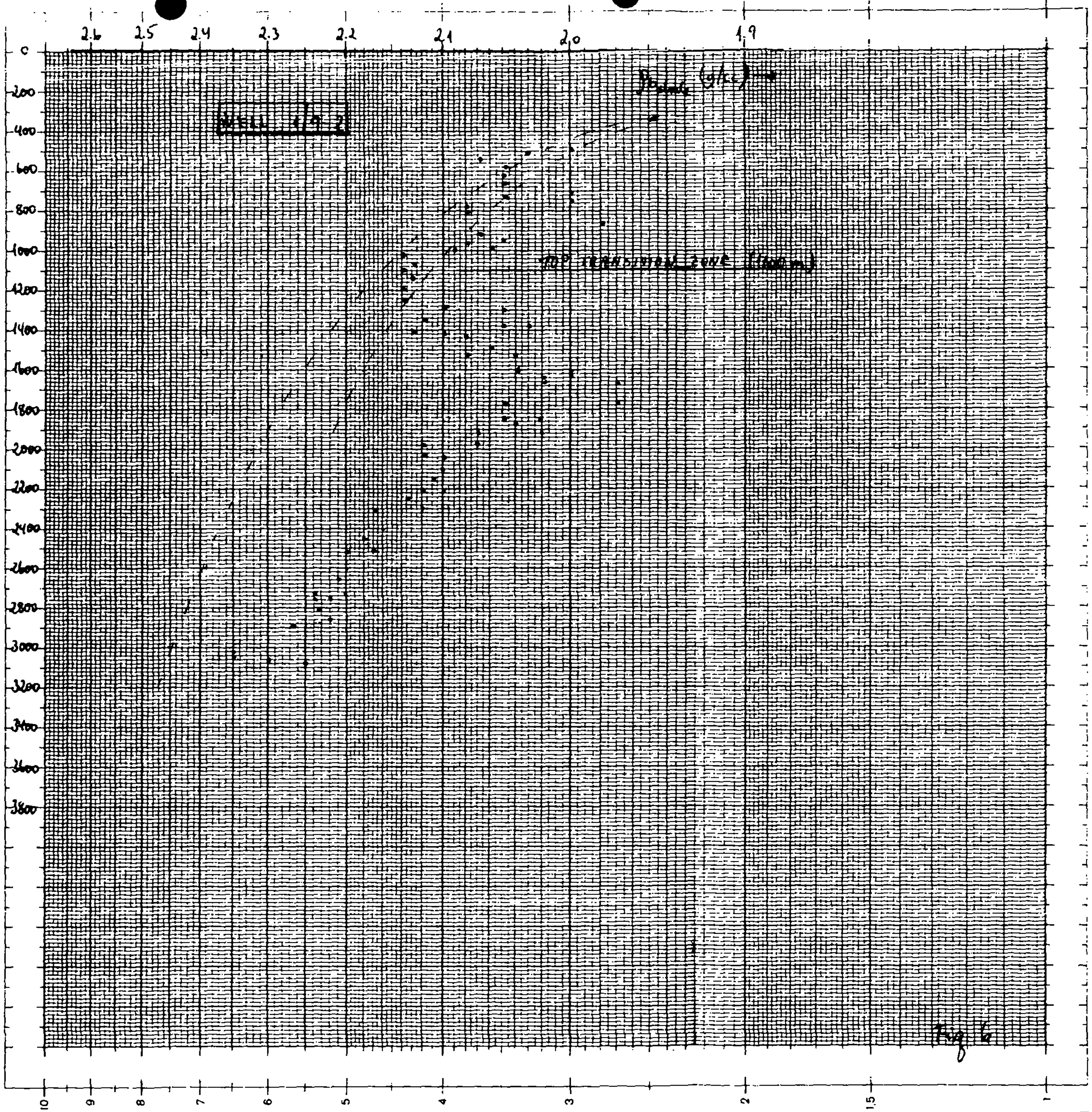


Fig. 3
Well 1/3-1
TOP TRANSITION ZONE (1030 m)
Gas effect
Gas effect
10
9
8
7
6
5
4
3
2
1.5
1
200
150
100
80
50
0
500
1000
1500
2000
2500
3000
3500
4000
4500
PLEISTOCENE
PLIOCENE
U. MIOCENE
M. MIOCENE
L. MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
DANIAN
MAASTRICHTIAN





WELL: 1/9 -1
ρb(sh)
TOP TRANSITION ZONE
: 1070 m (3500')
DEPTH (ft x 10^-3)
Pleistocene
Pliocene
Upper Miocene
Middle Miocene
Lower Miocene
Oligocene
Eocene
Paleocene
Danian
Maestrichtian
Fig. 5


Density (g/cc)
TOP TRANSITION ZONE (1000 m)
WELL 1/9-2
Fig 6

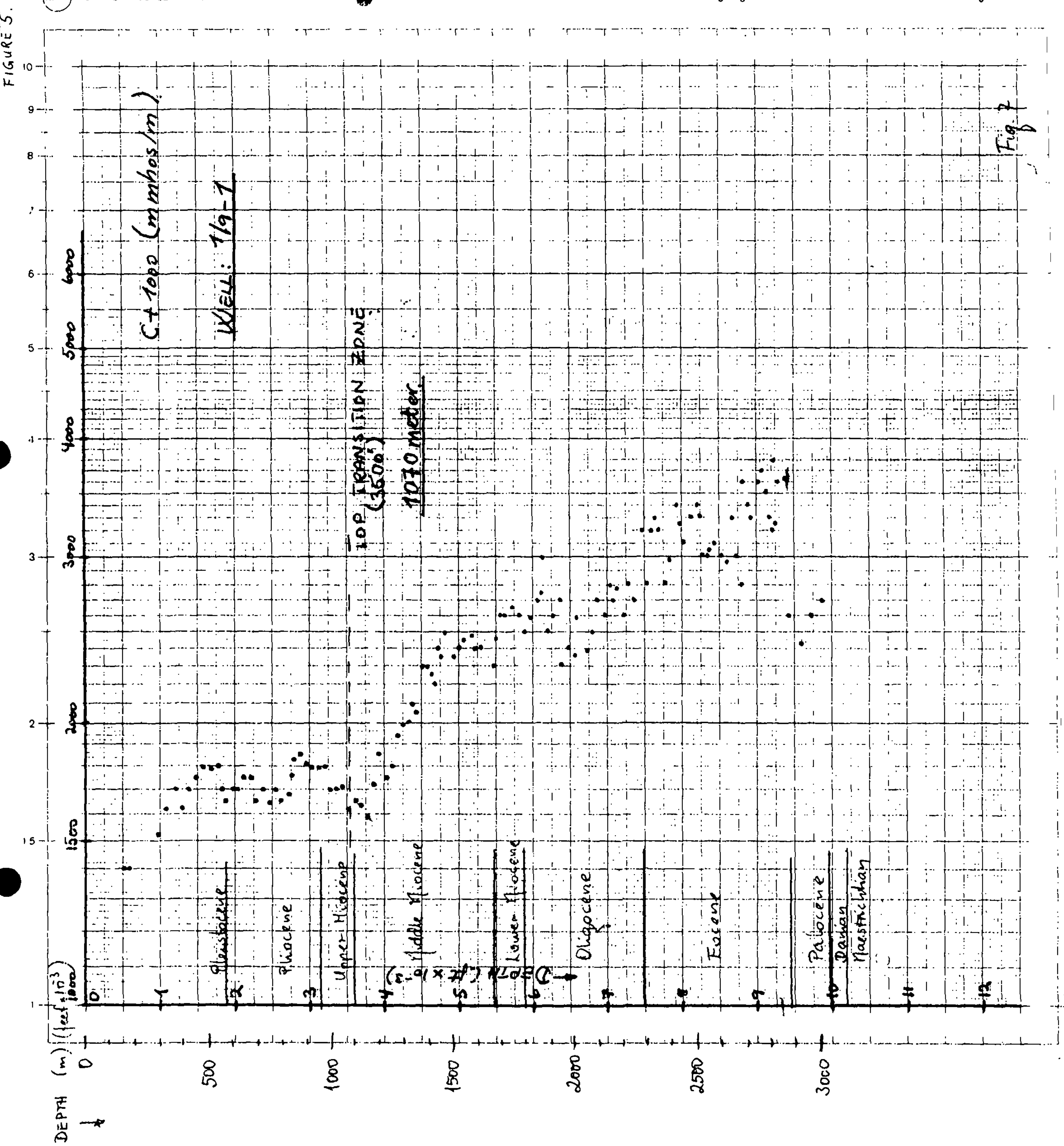
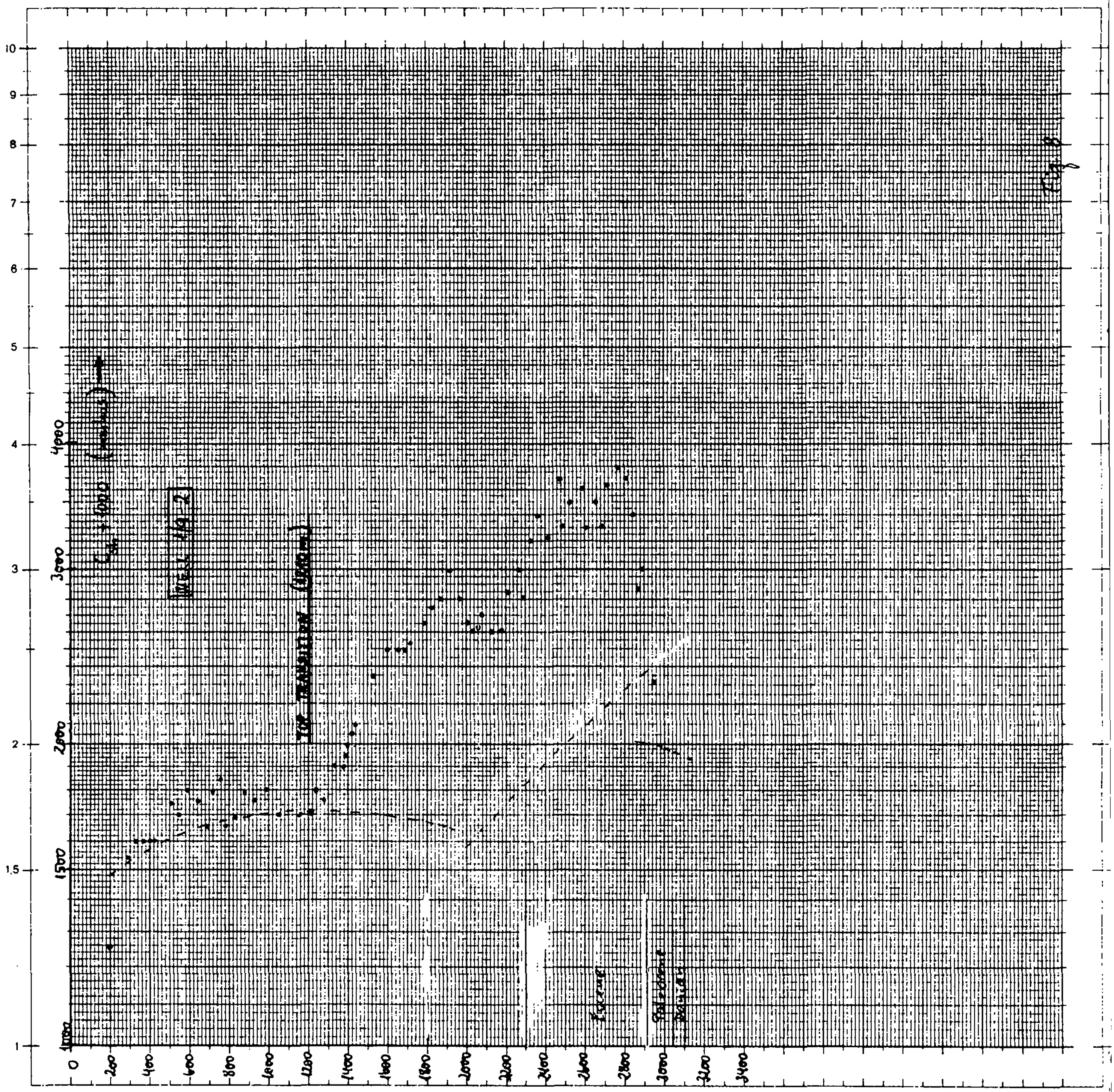
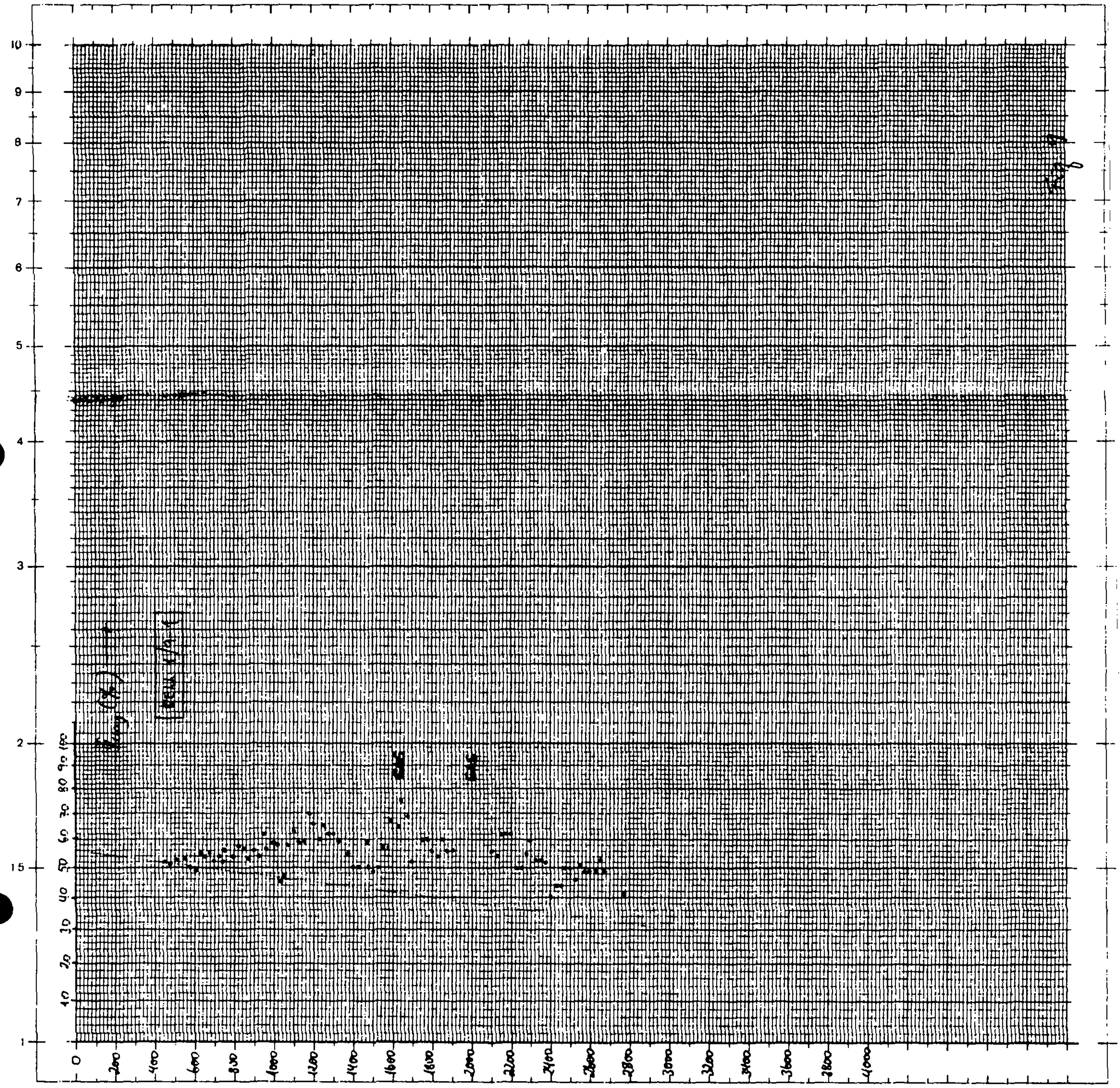


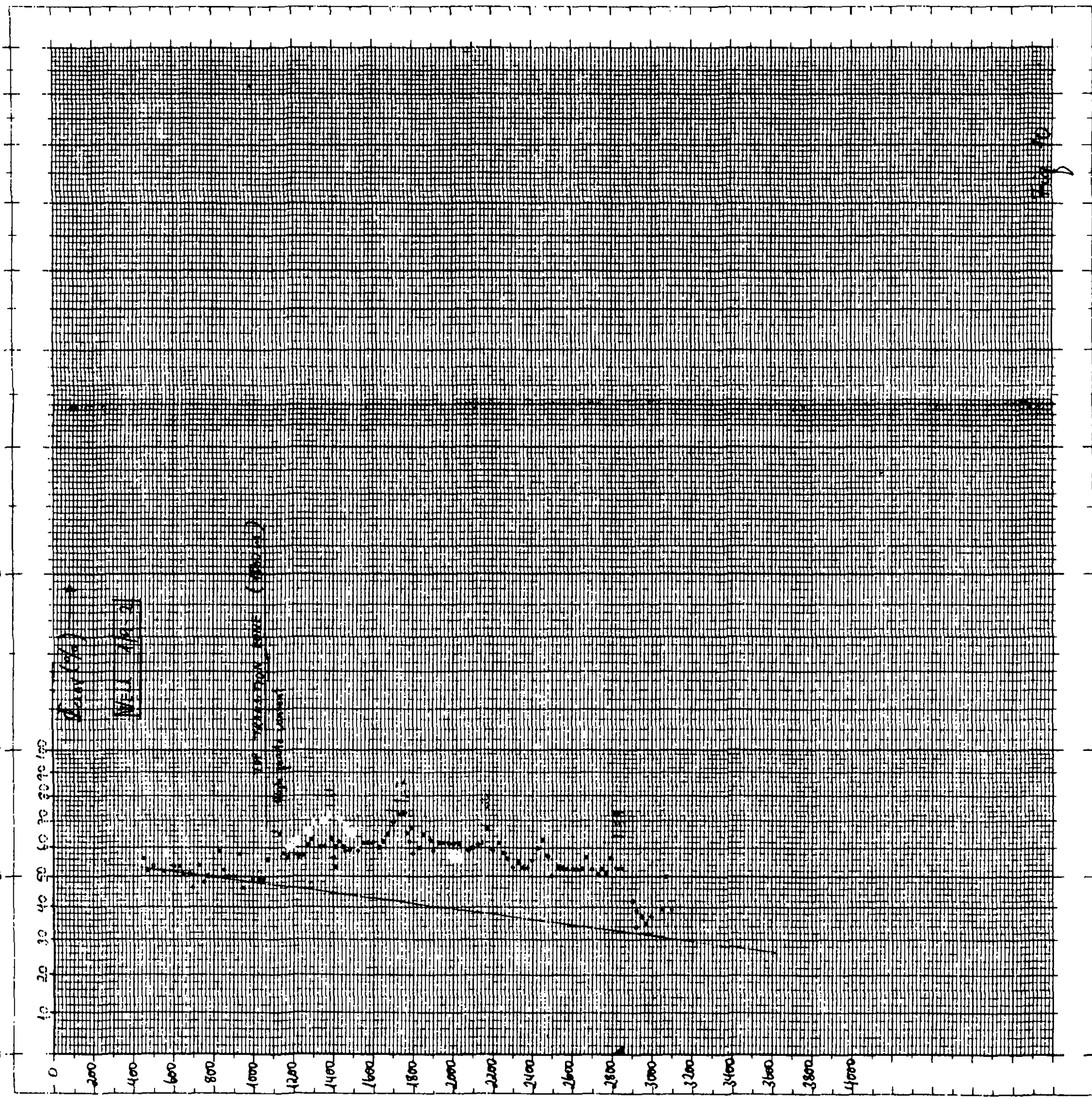
FIGURE 5.
Fig. 2
C + 1000 (mmhos/m)
WELL: 1/9-1
TOP TRANSITION ZONE (3500')
1070 meter
DEPTH (feet x 10^3)
Pleistocene
Pliocene
Upper Miocene
Middle Miocene
Lower Miocene
Oligocene
Eocene
Paleocene
Danian
Maestrichtian
1500
2000
3000
4000
5000
6000
0
1
2
3
4
5
6
7
8
9
10
11
12
(m)
0
500
1000
1500
2000
2500
3000
DEPTH

Eine Achse logar geteilt, von 1 bis 10, Einheit 250 mm, die andere gleichm in mm

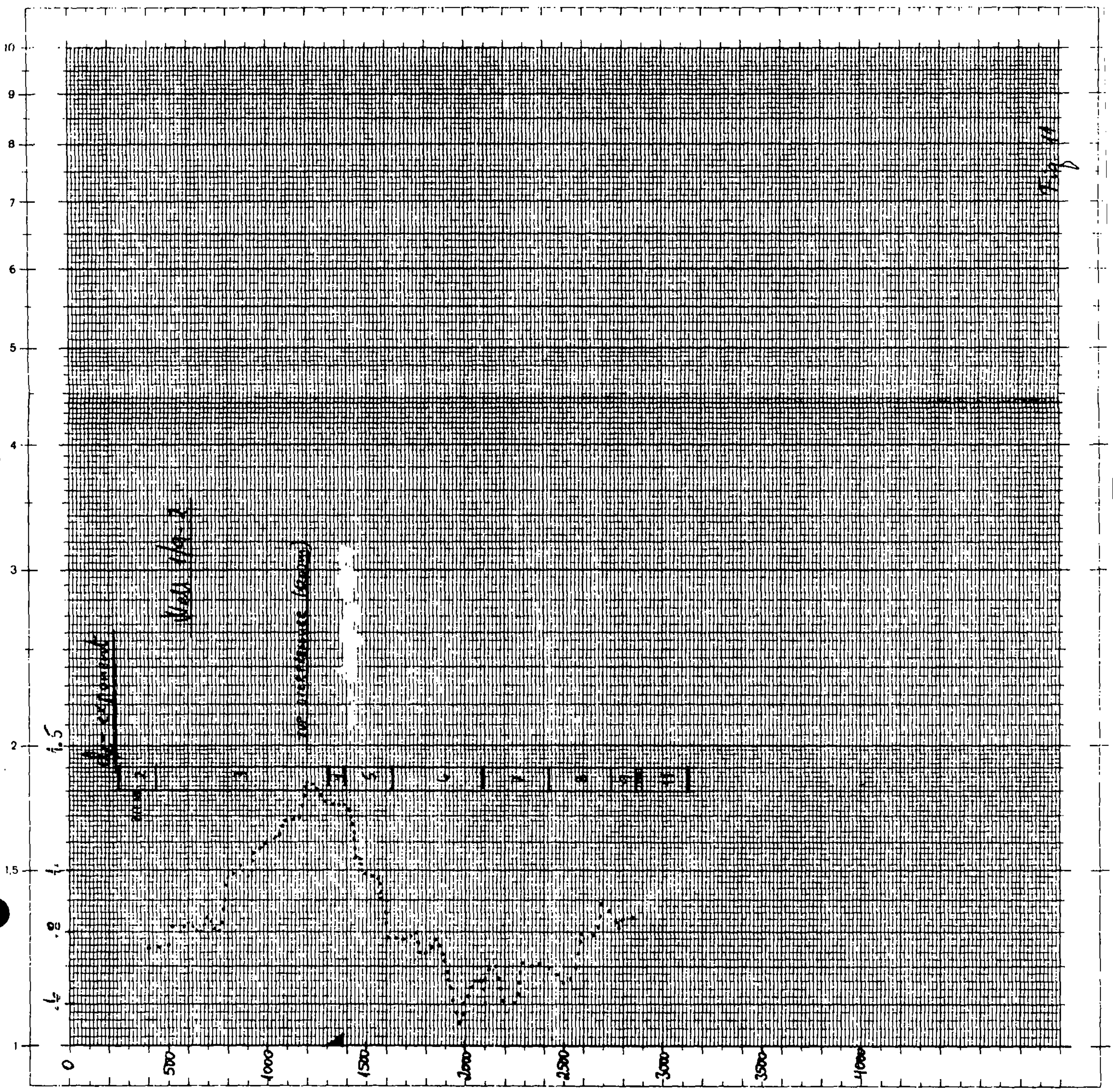



10
9
8
7
6
5
4
3
2
1.5
1
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000

Eine Achse logar. geteilt, von 1 bis 10, Einheit 250 mm, die andere gleichm. in mm



Eine Achse logar. geteilt, von 1 bis 10, Einheit 250 mm, die andere gleichm. in mm



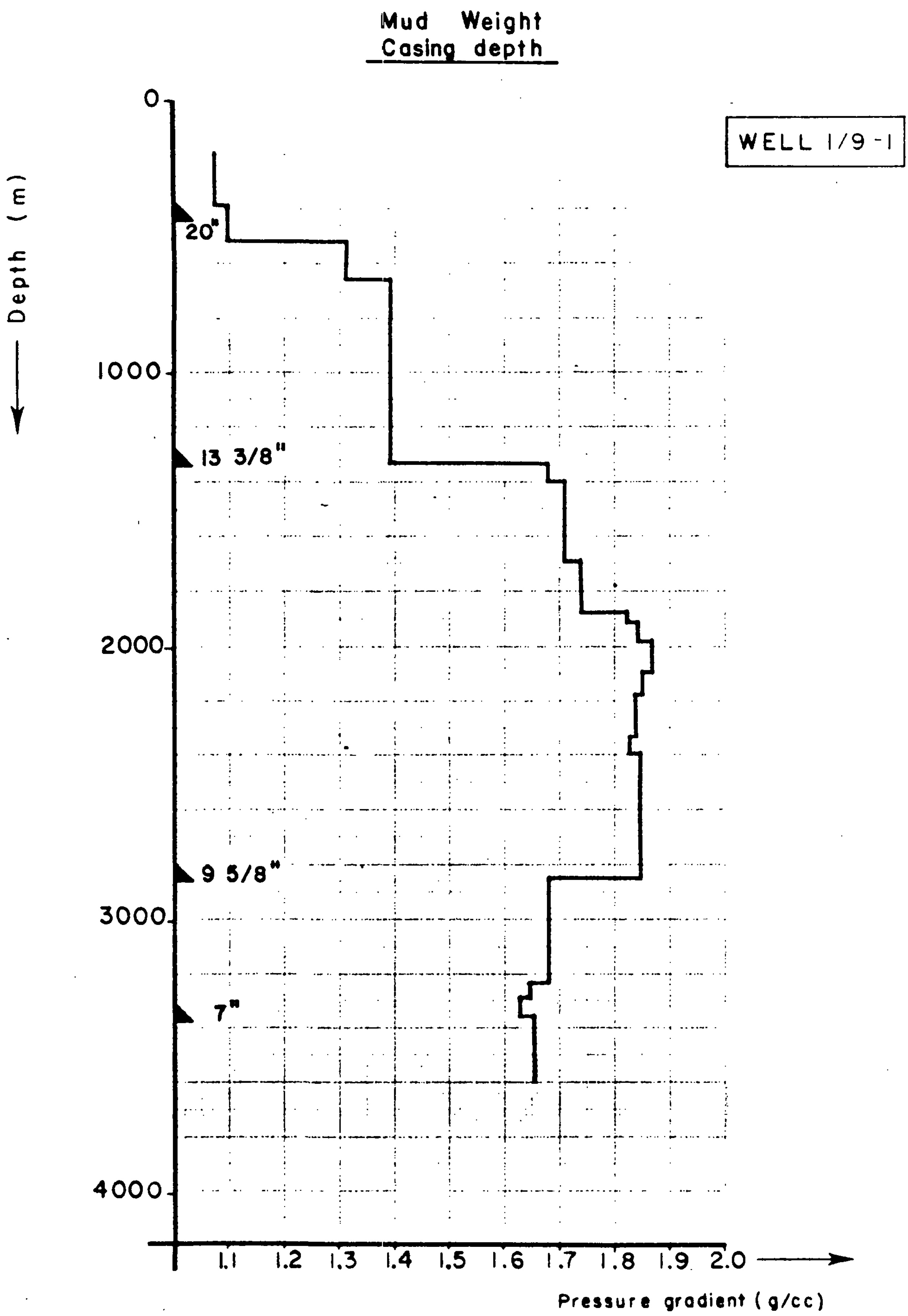
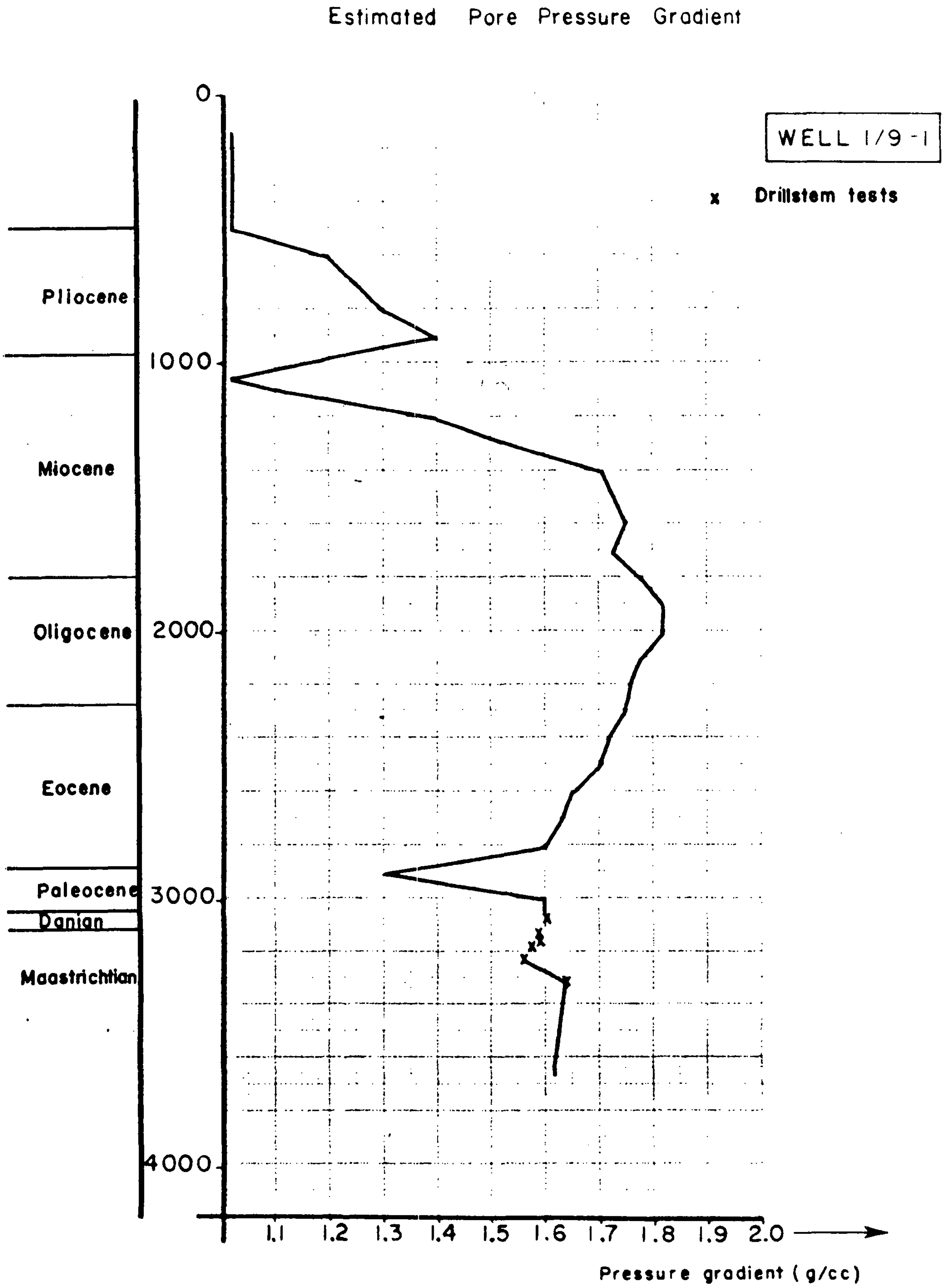
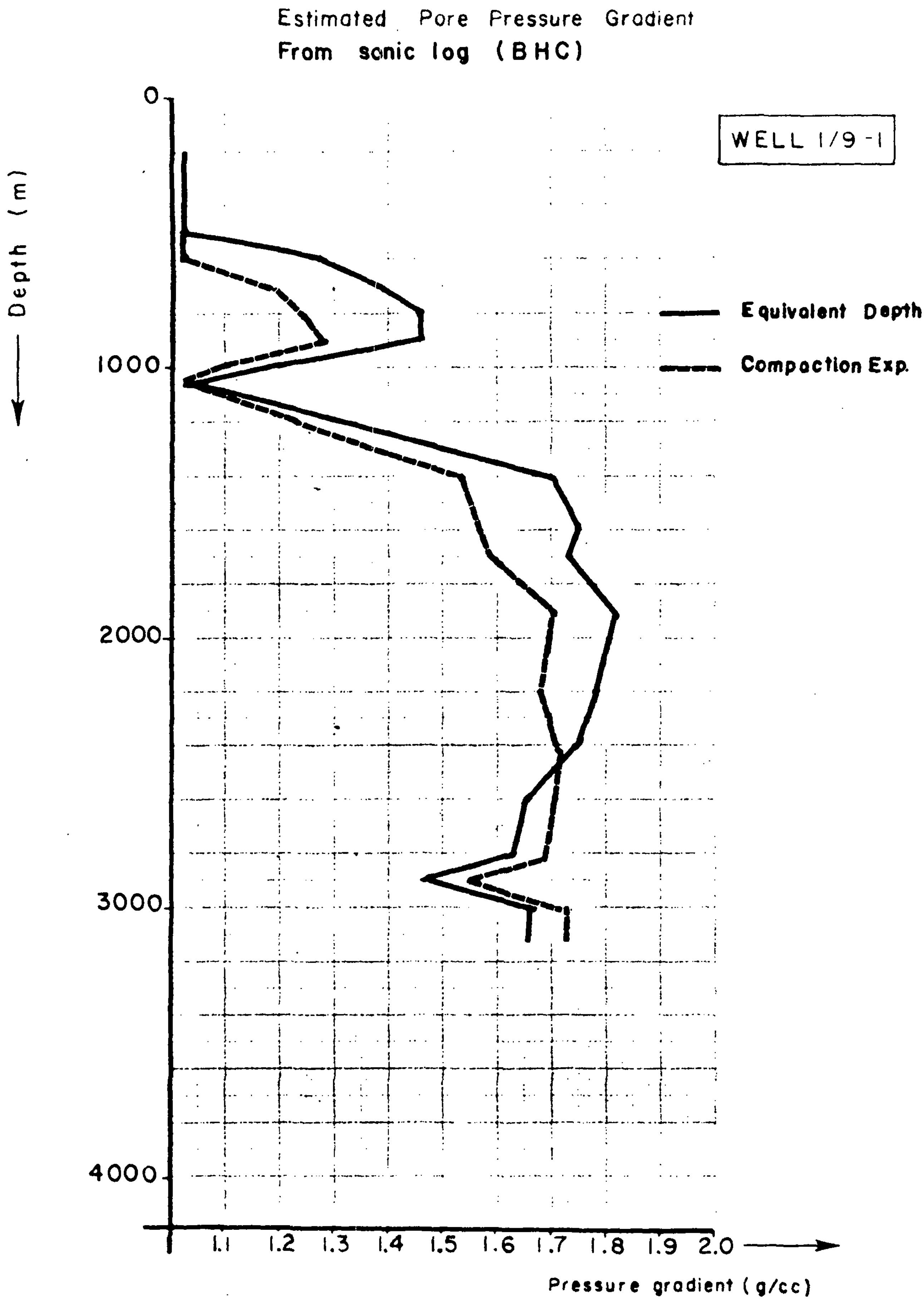

Mud Weight
Casing depth
WELL 1/9-1
Depth (m)
0
1000
2000
3000
4000
20"
13 3/8"
9 5/8"
7"
1.1 1.2 1.3 1.4 1.5 1.6 1.7 1.8 1.9 2.0
Pressure gradient (g/cc)

Fig.12



Estimated Pore Pressure Gradient
WELL 1/9-1
x Drillstem tests
Pliocene
Miocene
Oligocene
Eocene
Paleocene
Danian
Maastrichtian
0
1000
2000
3000
4000
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig.13



Estimated Pore Pressure Gradient
From sonic log (BHC)
WELL 1/9-1
Depth (m)
0
1000
2000
3000
4000
Equivalent Depth
Compaction Exp.
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 14

Estimated Pore Pressure Gradient
from density log (FDC)

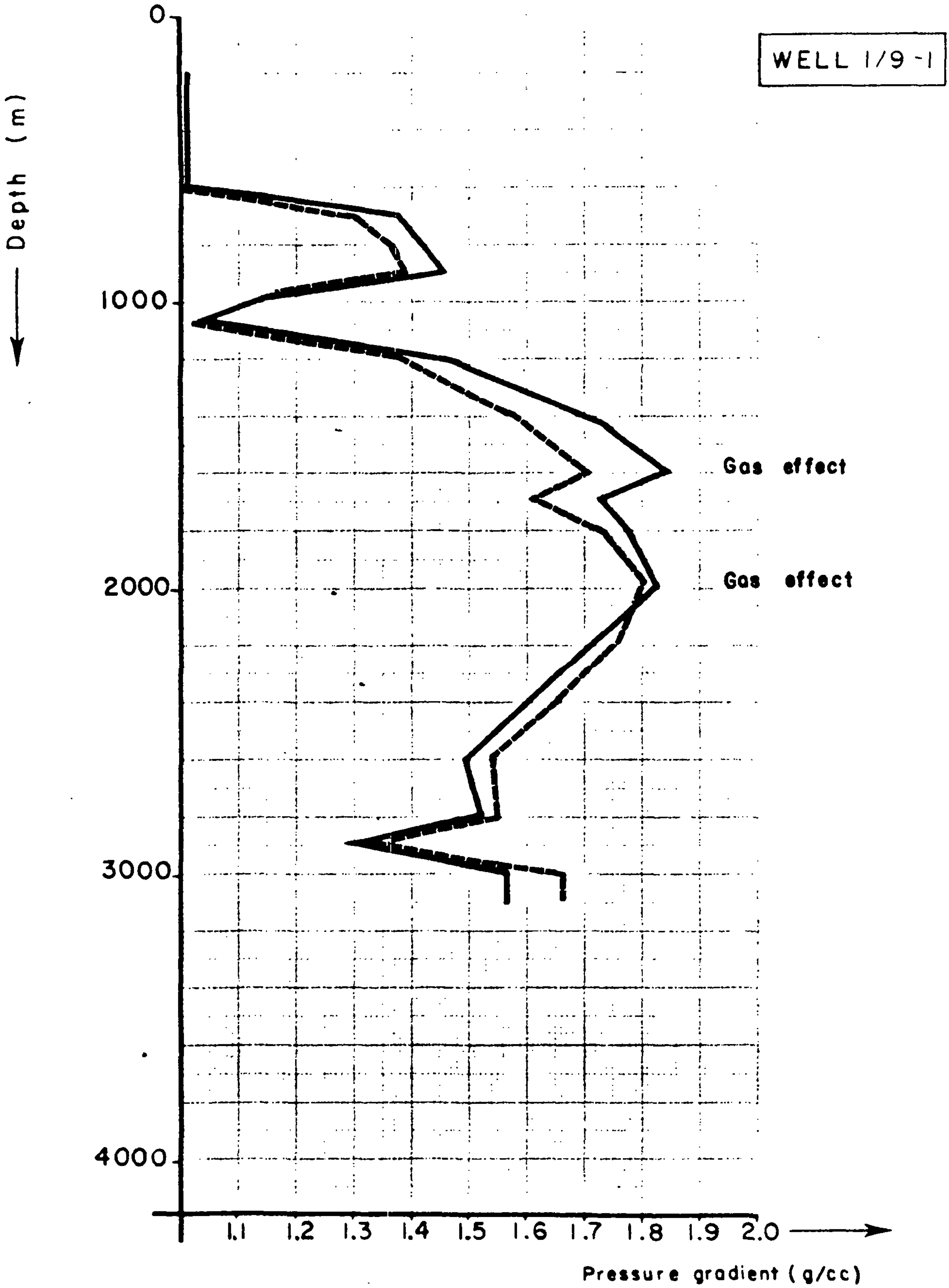


Fig.15

Estimated Pore Pressure Gradient
From conductivity in shales

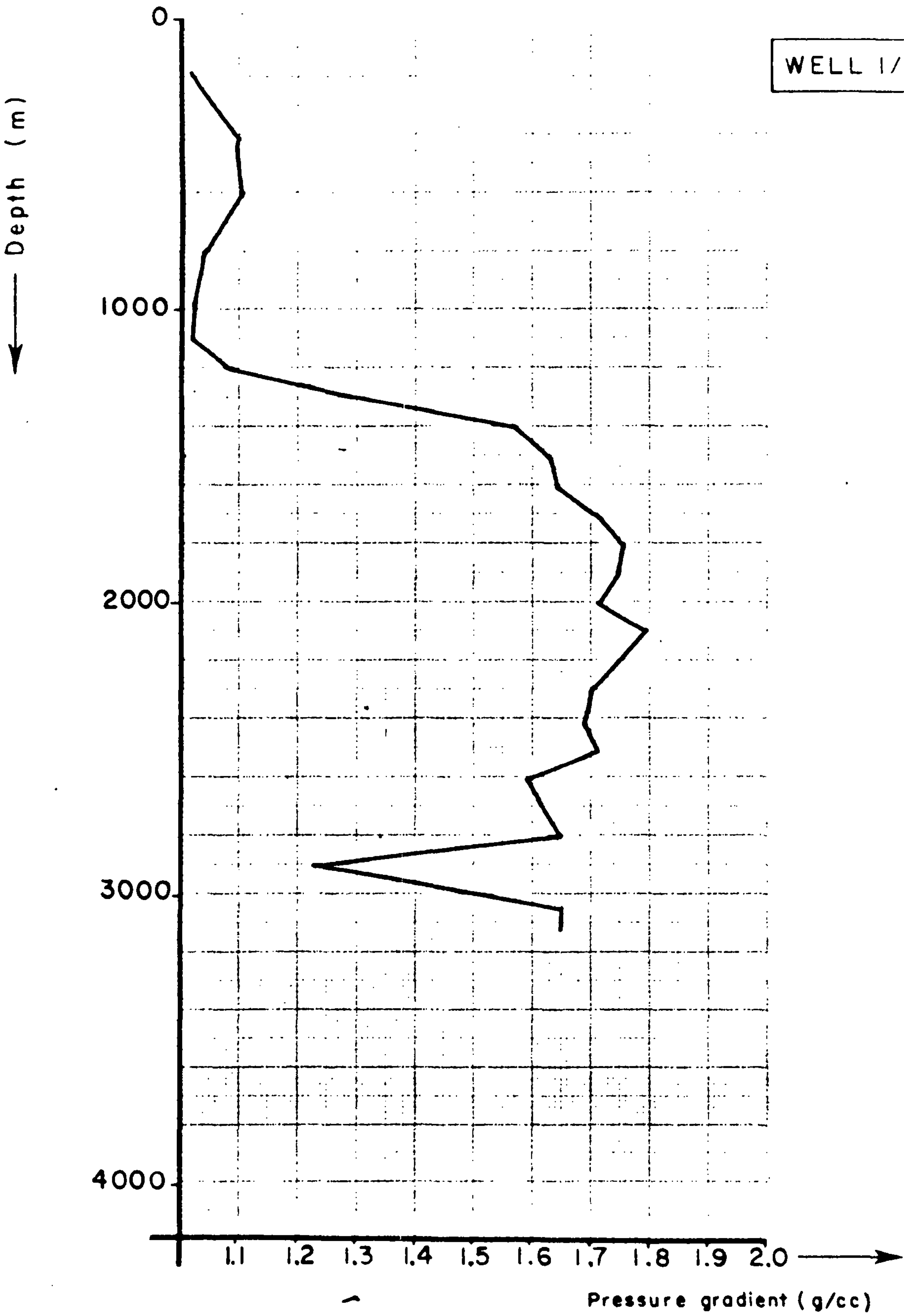


Fig. 16

Relationship between Pressure Gradient and clay porosity

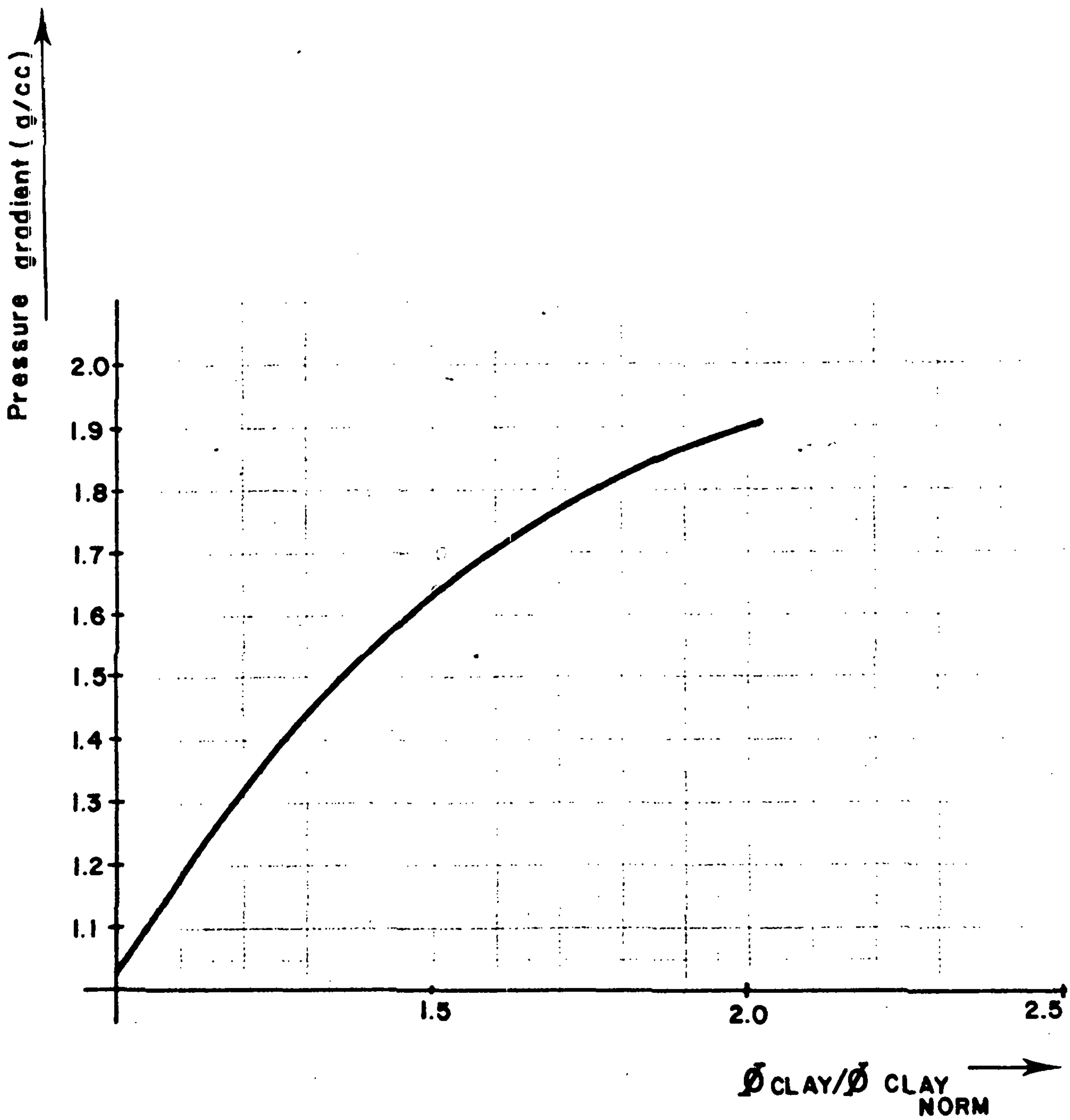


Fig.17

Estimated Pore Pressure Gradient
from clay porosity

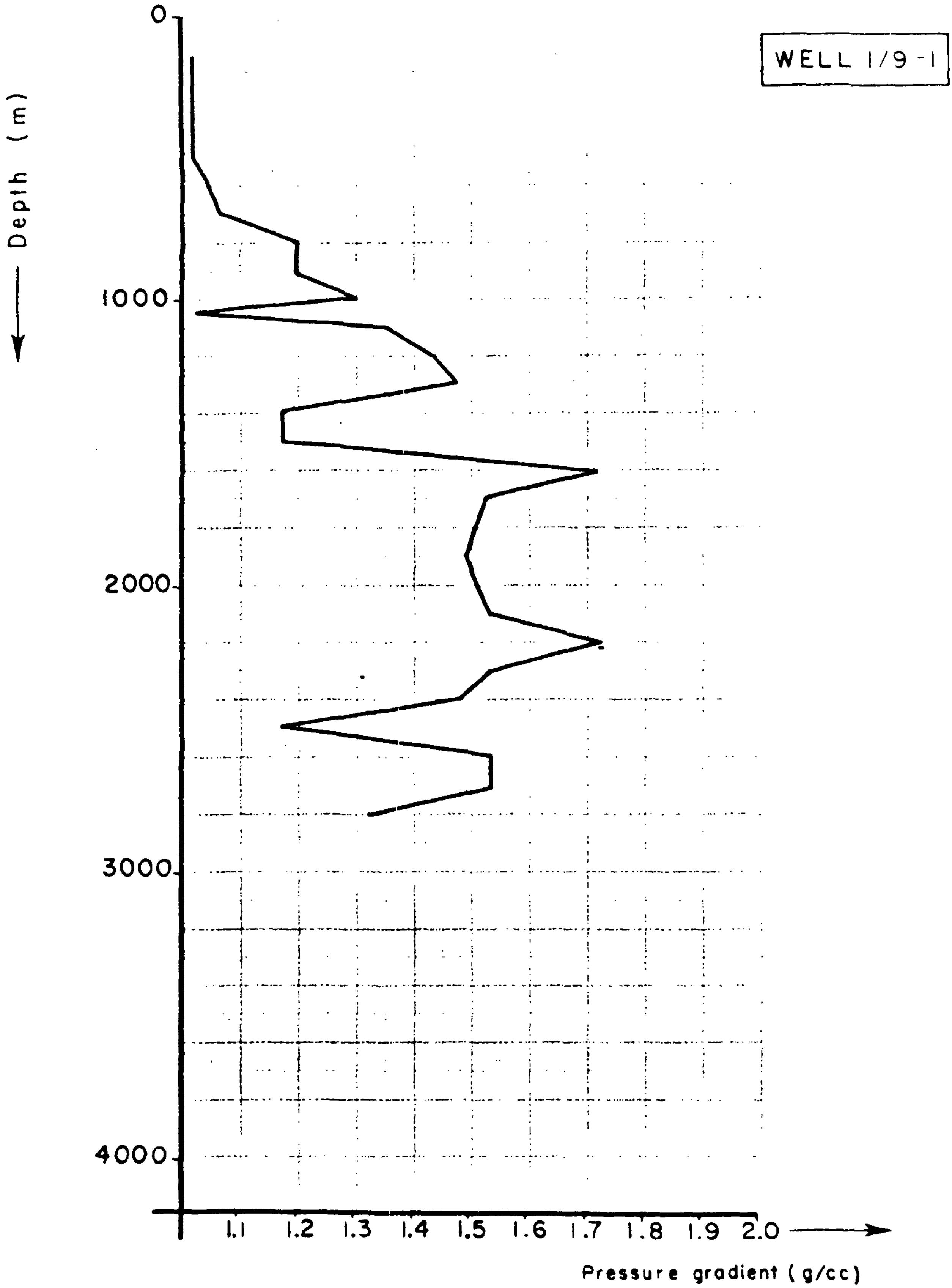
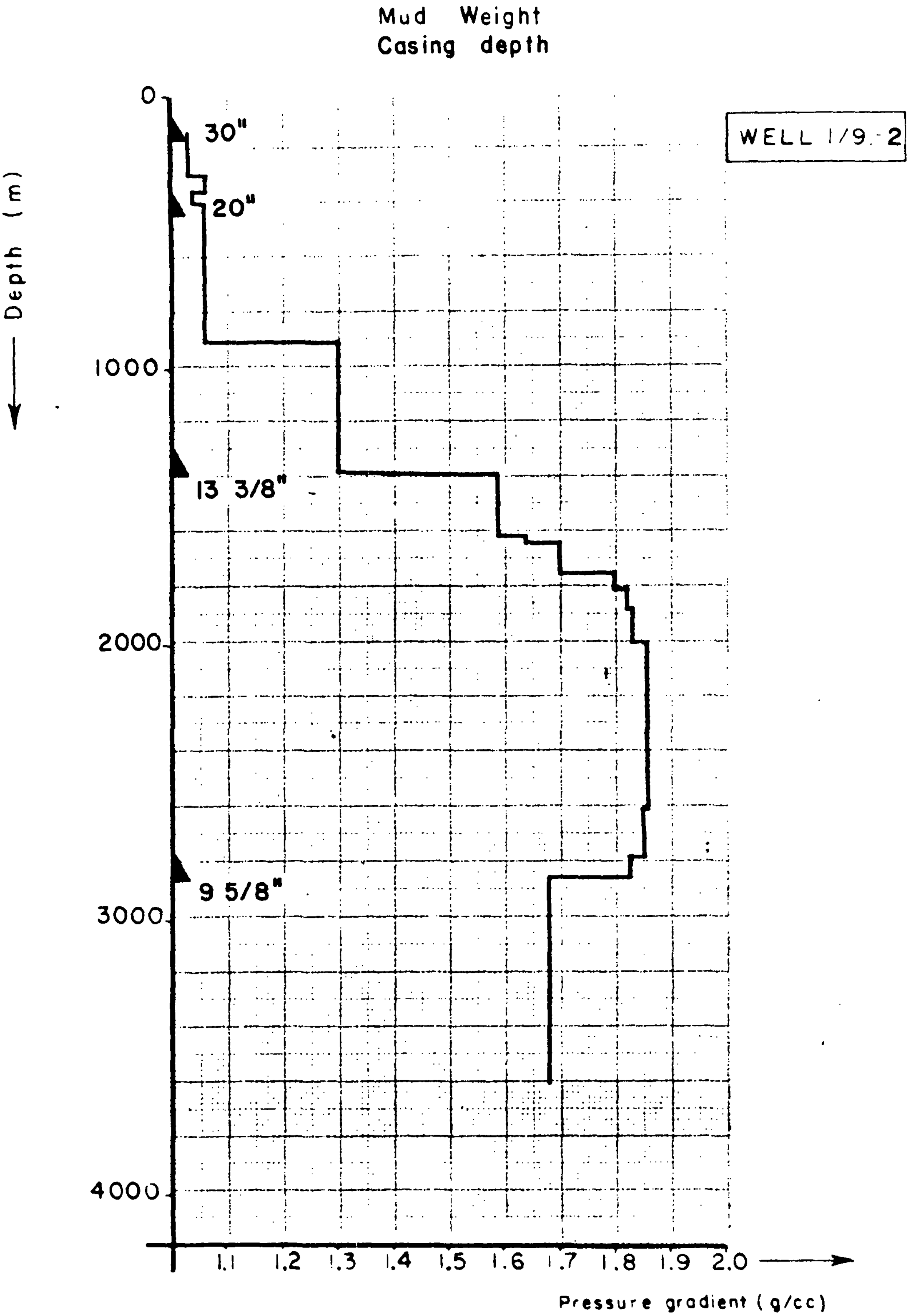
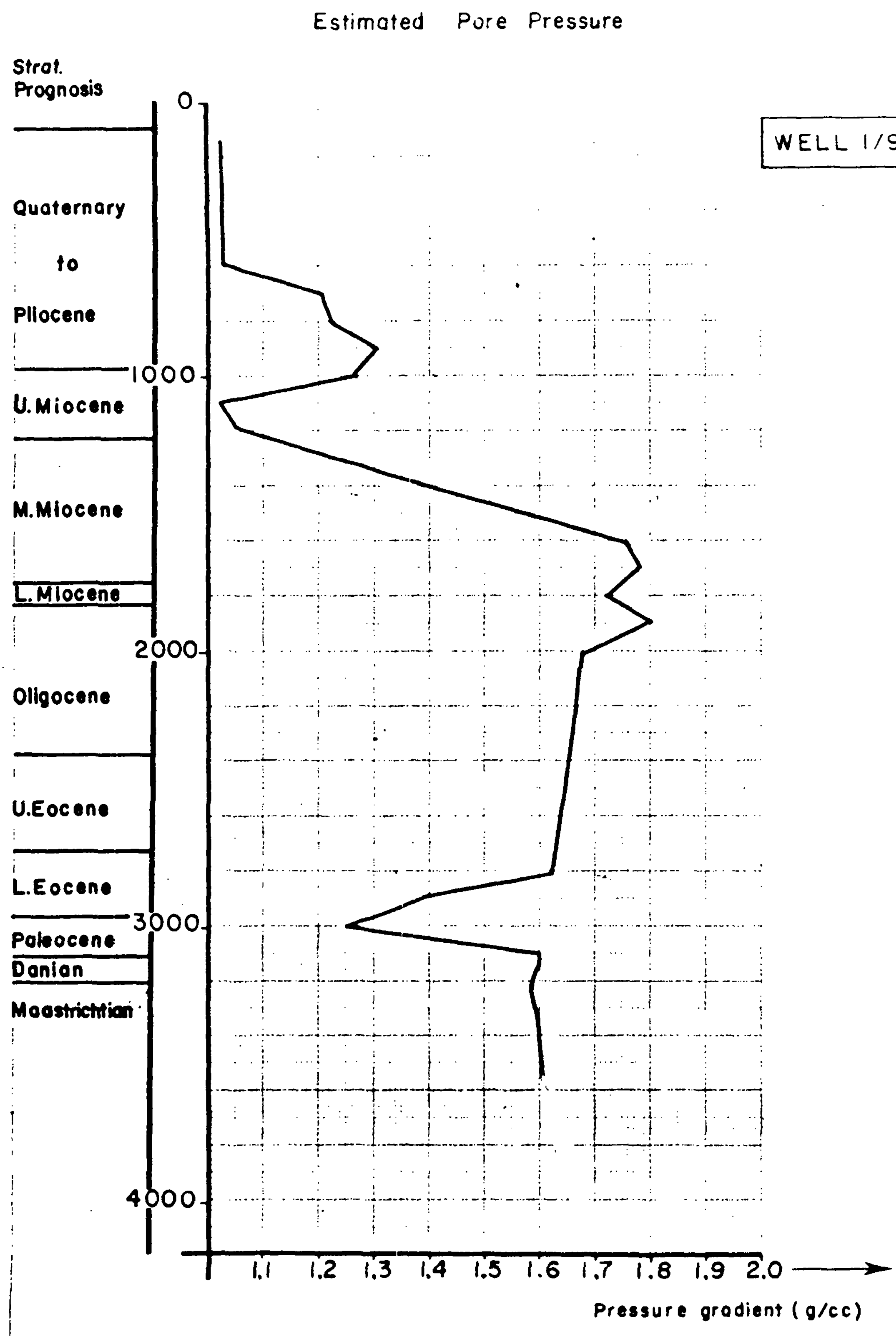


Fig. 18



Mud Weight
Casing depth
WELL 1/9-2
Depth (m)
0
1000
2000
3000
4000
30"
20"
13 3/8"
9 5/8"
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig.19



Estimated Pore Pressure
Strat. Prognosis
WELL 1/9 2
Quaternary
to
Pliocene
U. Miocene
M. Miocene
L. Miocene
Oligocene
U. Eocene
L. Eocene
Paleocene
Danian
Maastrichtian
0
1000
2000
3000
4000
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 20

Estimated Pore Pressure Gradient
From sonic log (BHC)

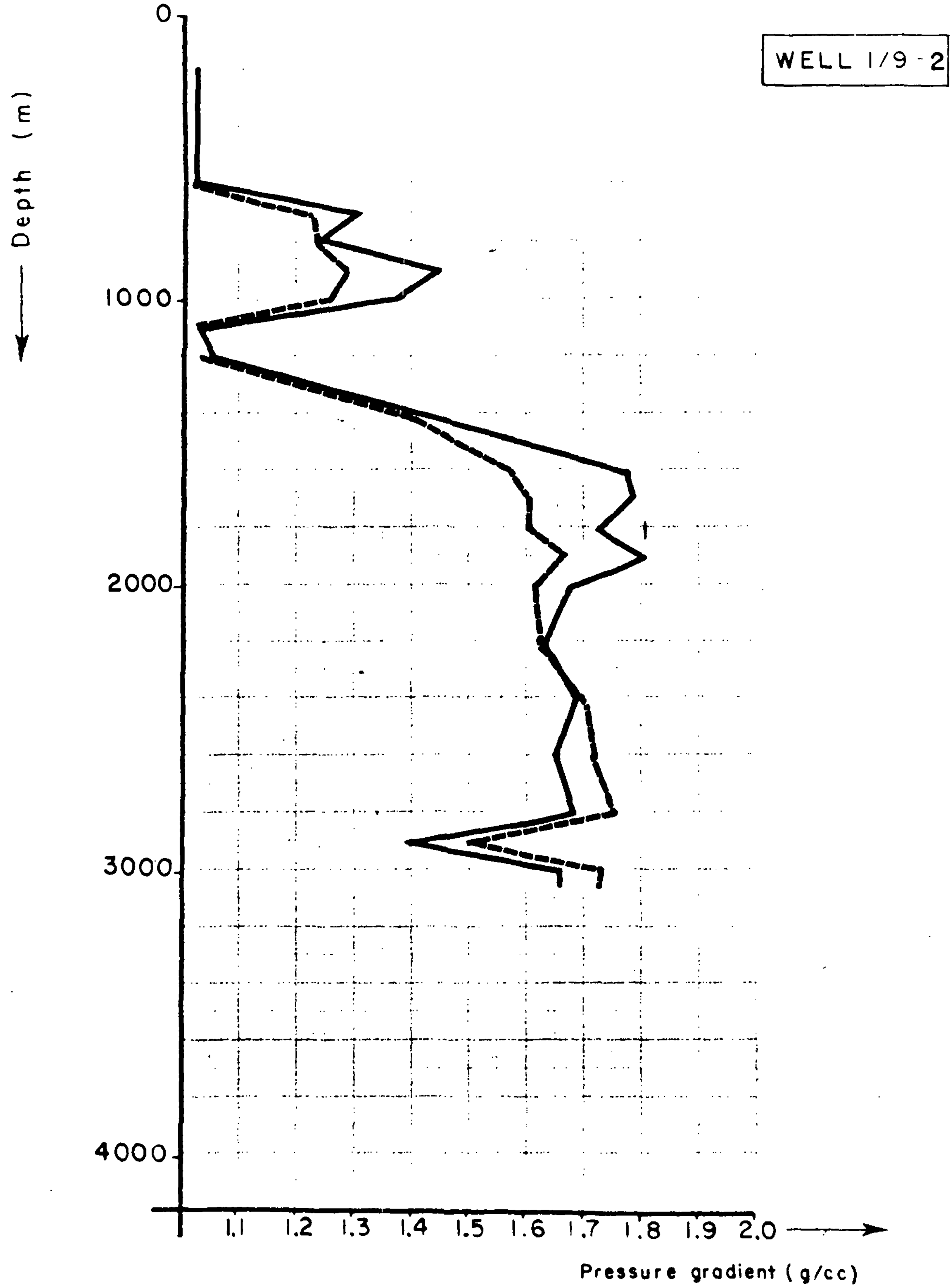


Fig. 21

Estimated Pore Pressure Gradient
From density log (FDC)

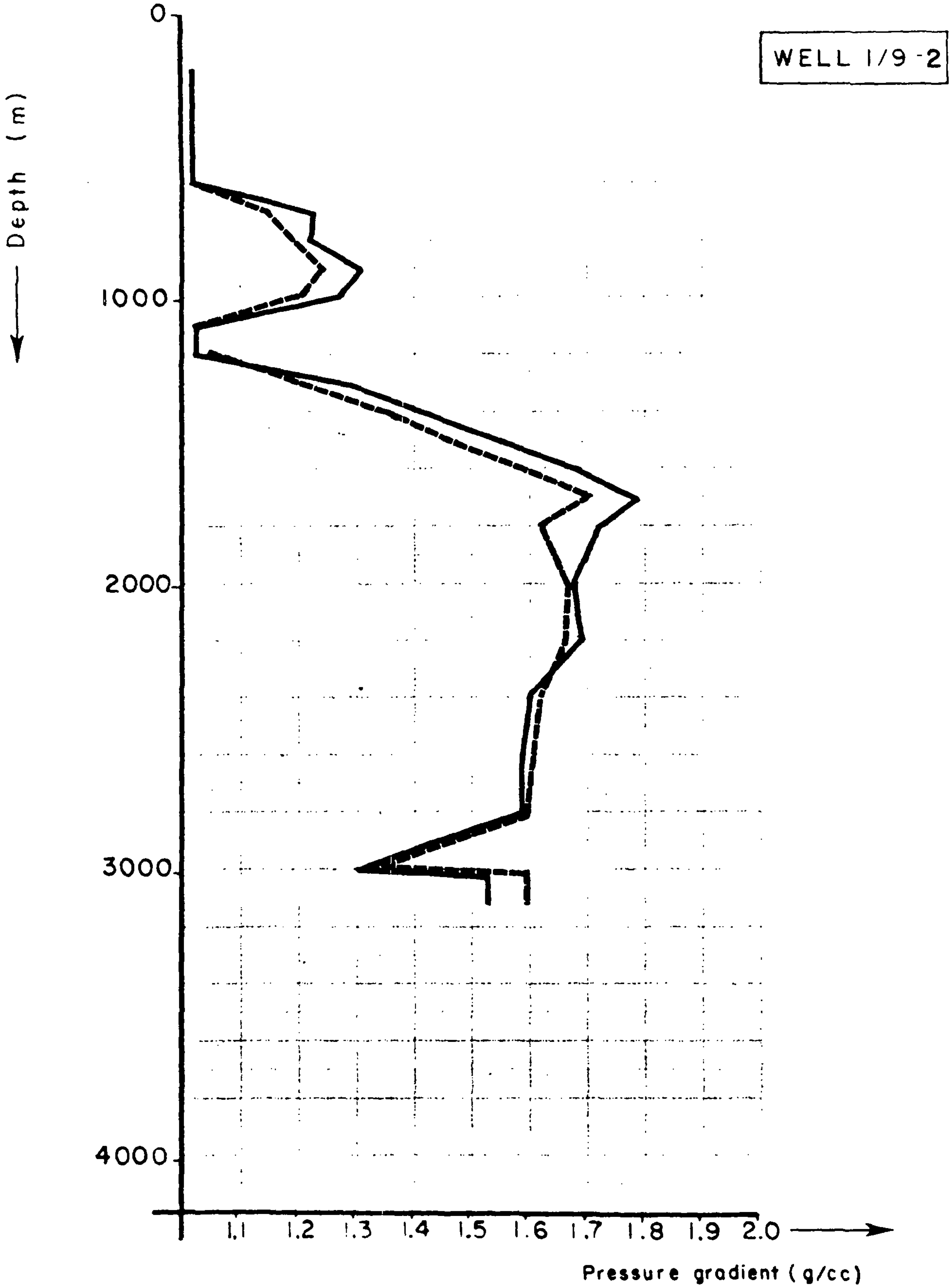


Fig.22

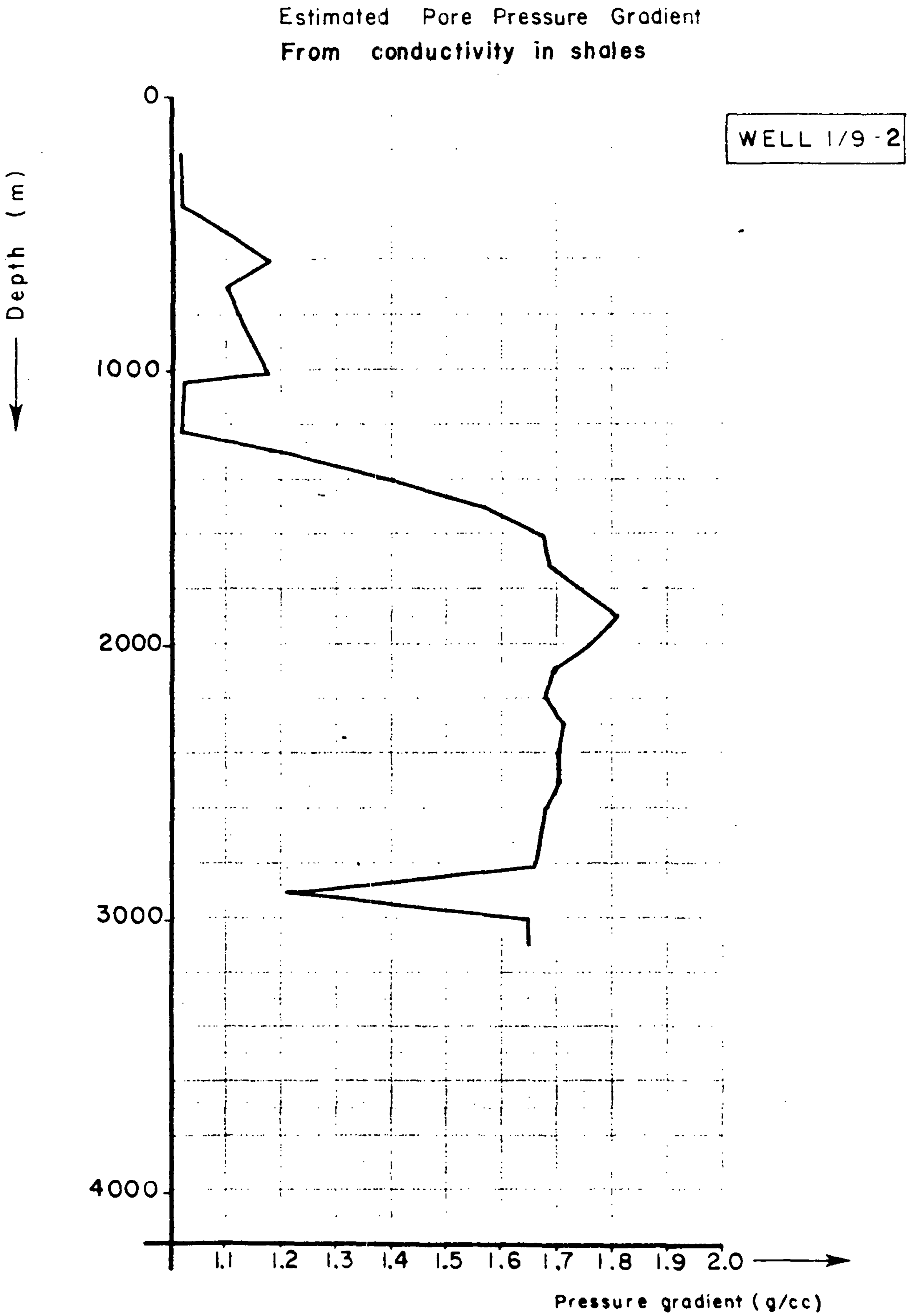

Estimated Pore Pressure Gradient
From conductivity in shales
WELL 1/9-2
Depth (m)
0
1000
2000
3000
4000
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 23

Estimated Pore Pressure Gradient
From clay porosity

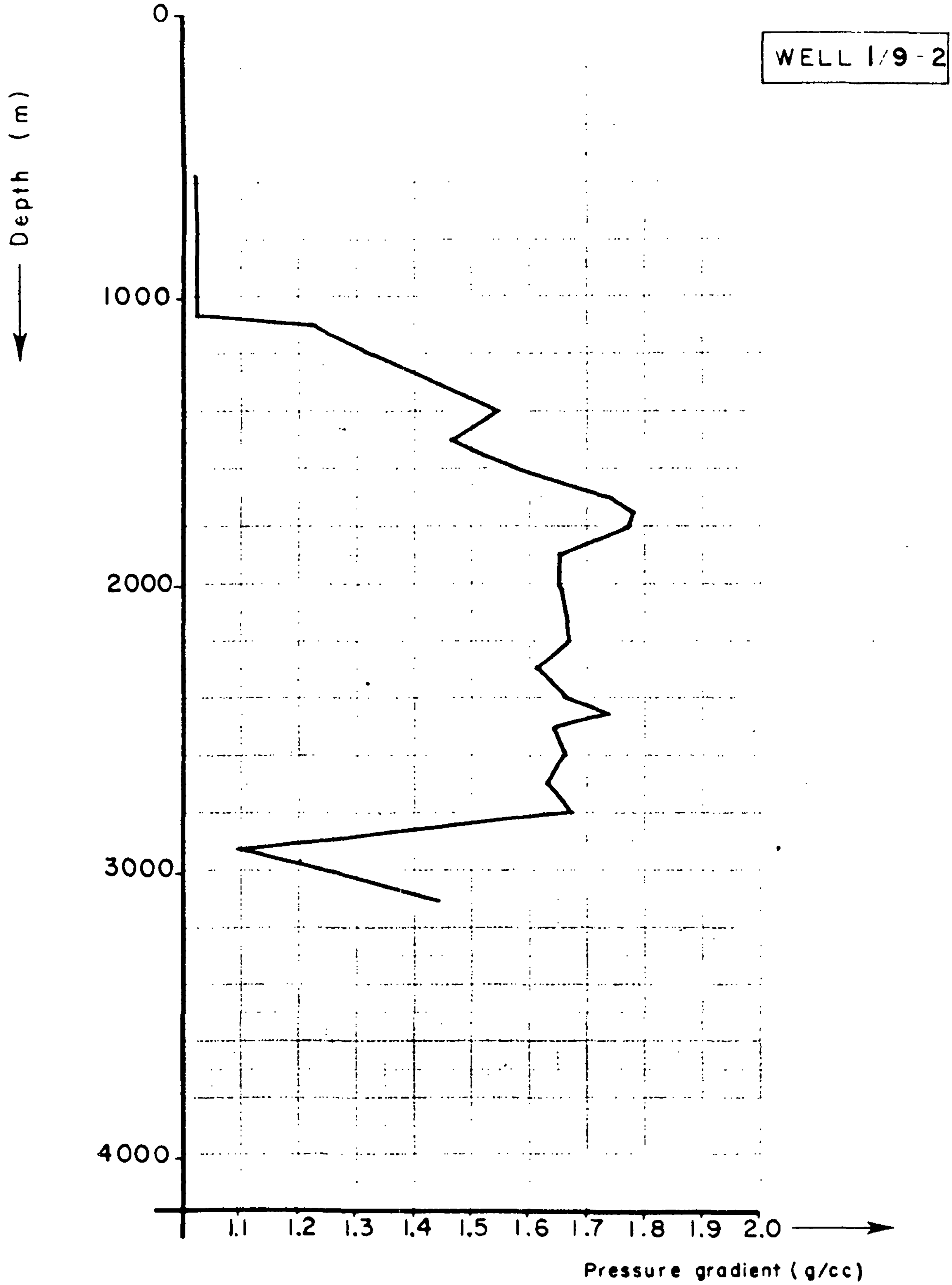


Fig.24

Estimated Fracture Gradients, based on:
Andersen, Ingram & Zanier

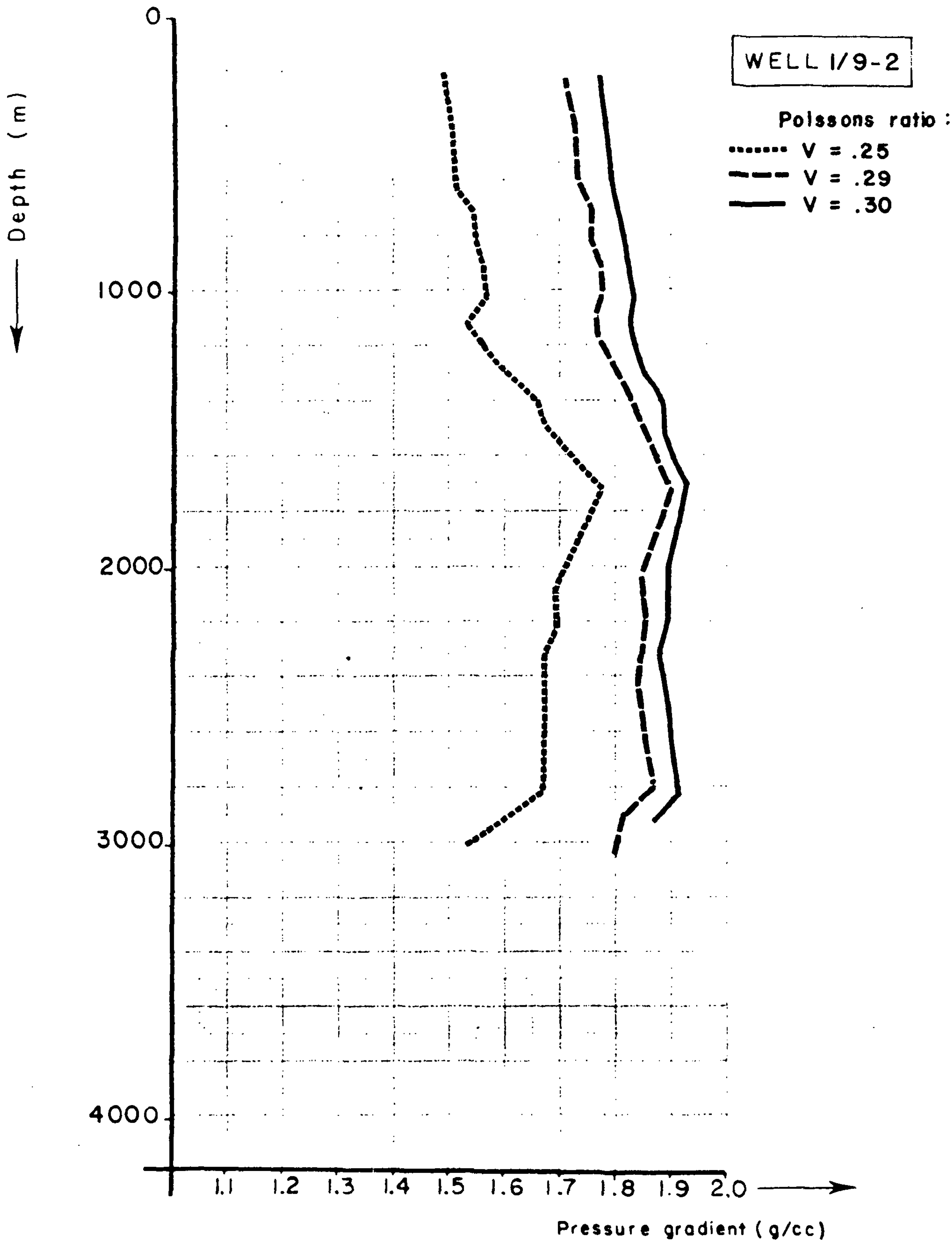
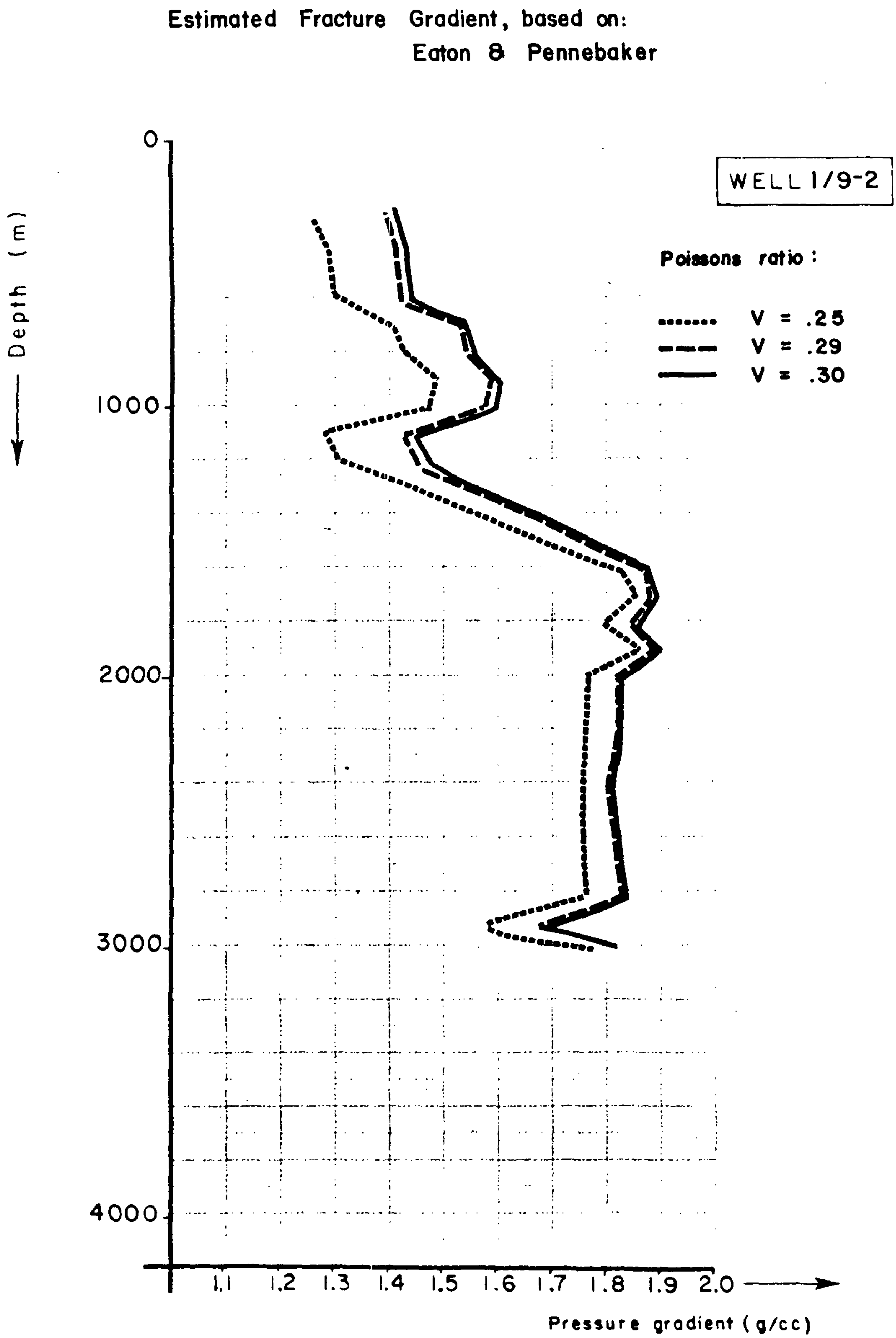


Fig. 25



Estimated Fracture Gradient, based on:
Eaton & Pennebaker
WELL 1/9-2
Poissons ratio :
V = .25
V = .29
V = .30
Depth (m)
0
1000
2000
3000
4000
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 26

POISSON'S RATIO VS. DEPTH

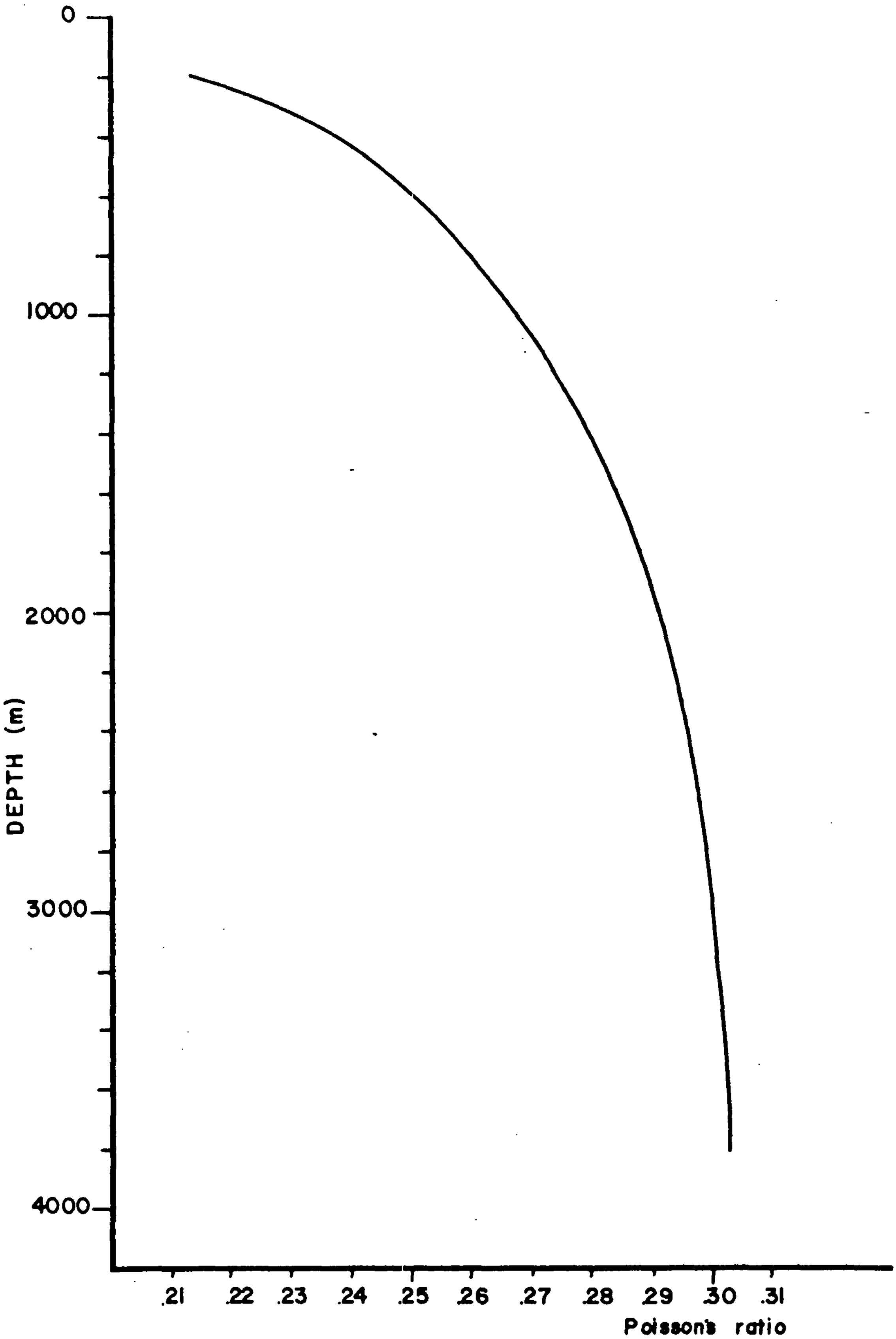


Fig. 27

Estimated Fracture Gradients, based on:
Variable Poissons ratio vs. depth

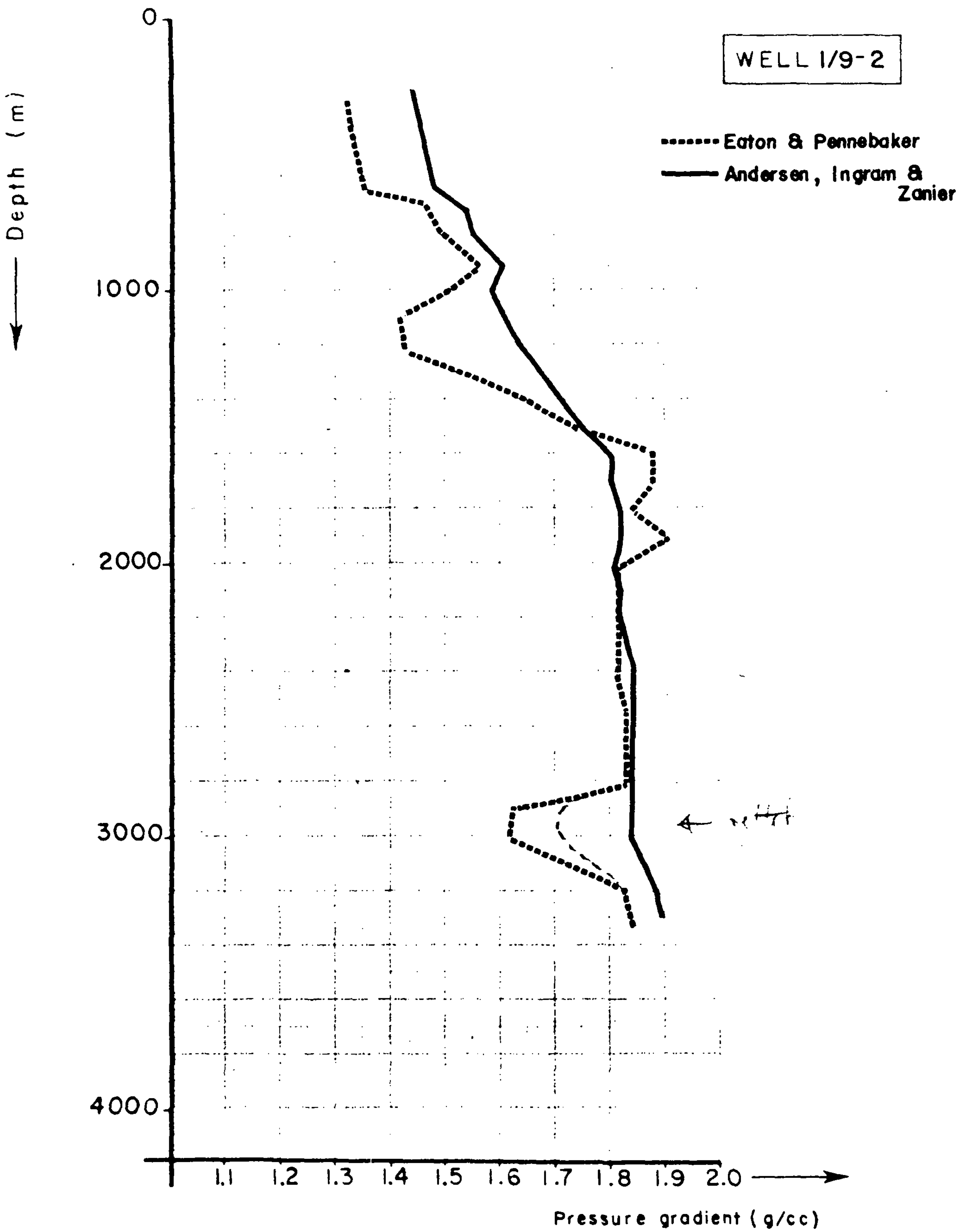


Fig. 28

Quartz, Clay and Porosity in Shale WELL 1/9-2

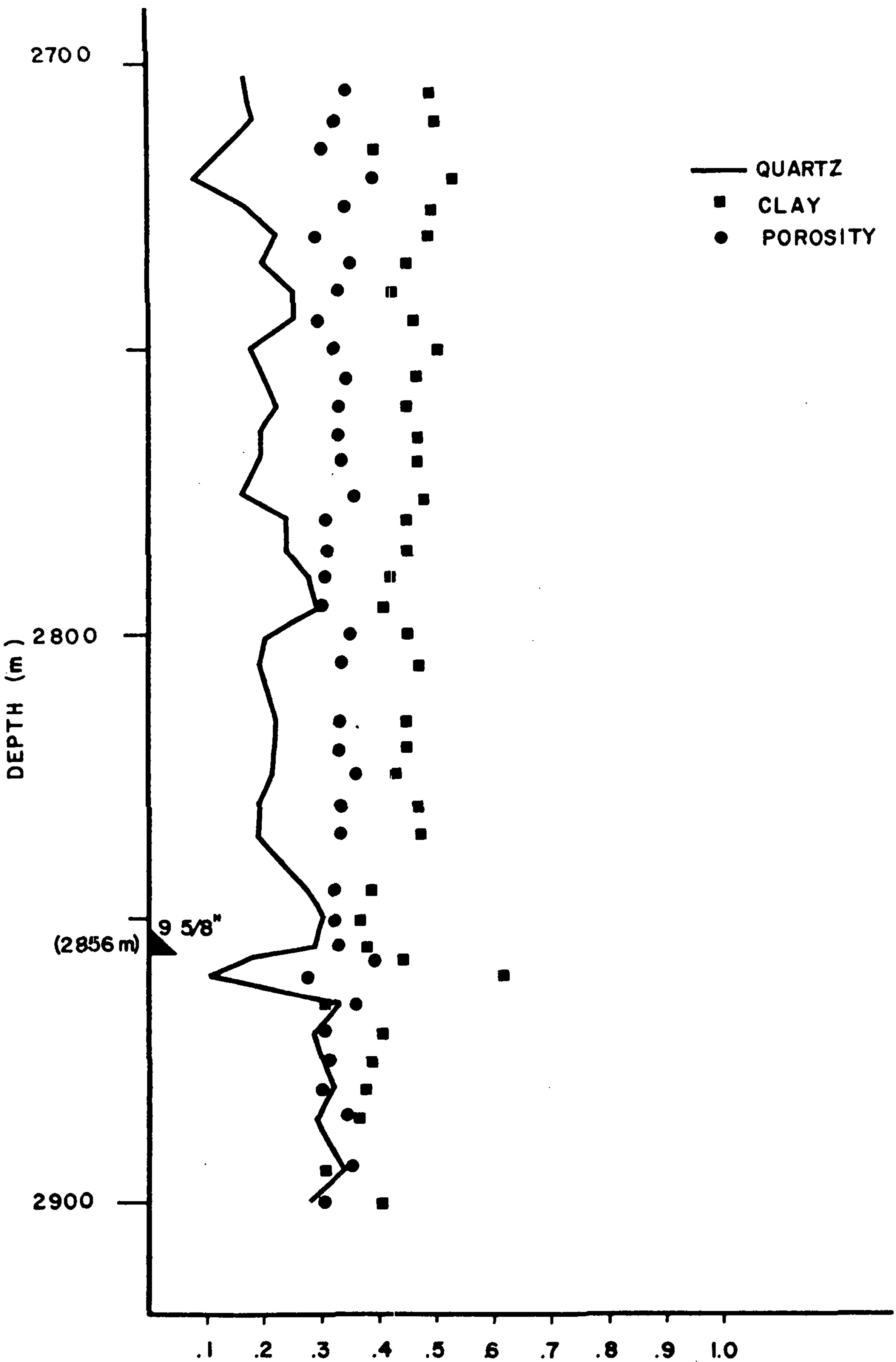
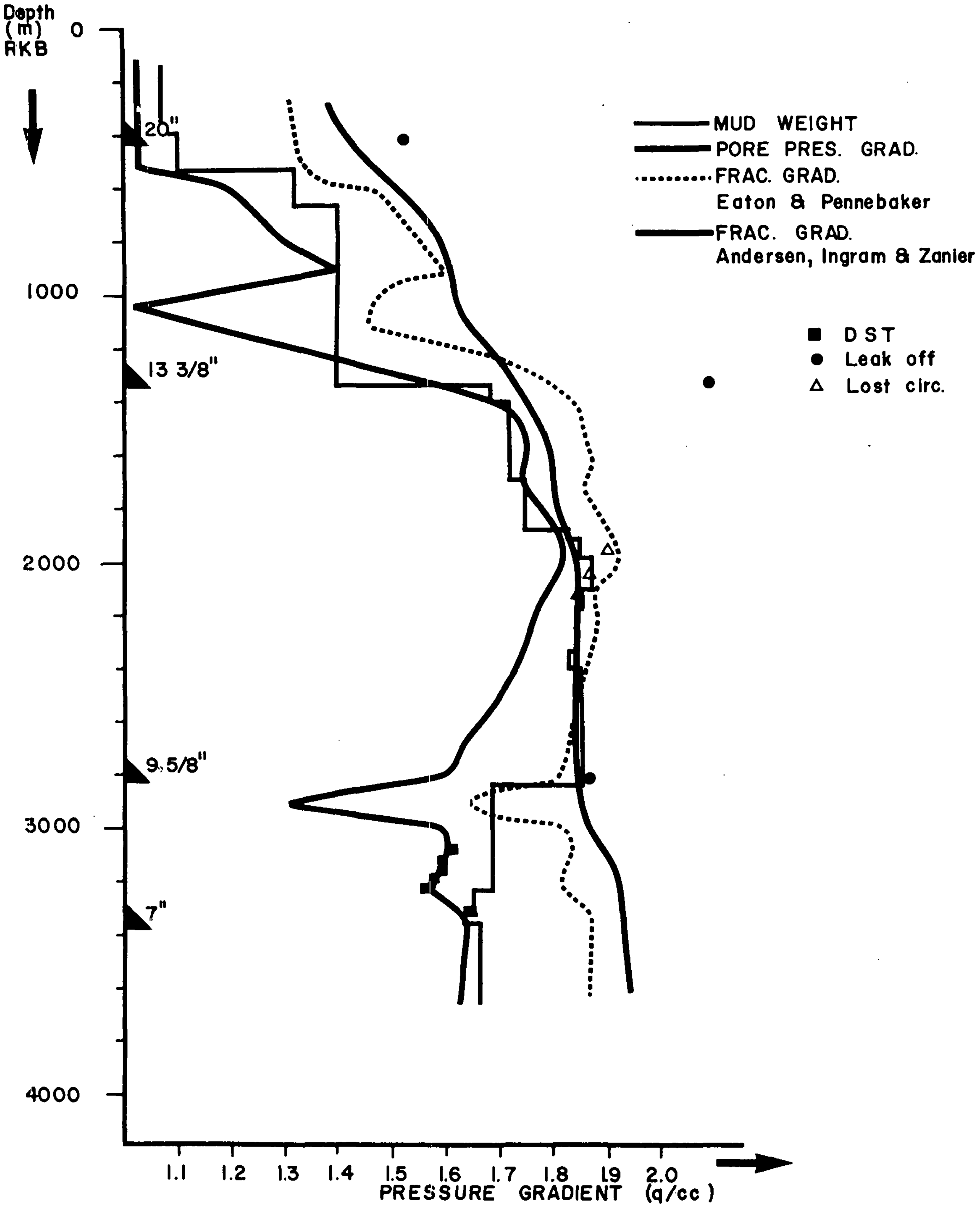
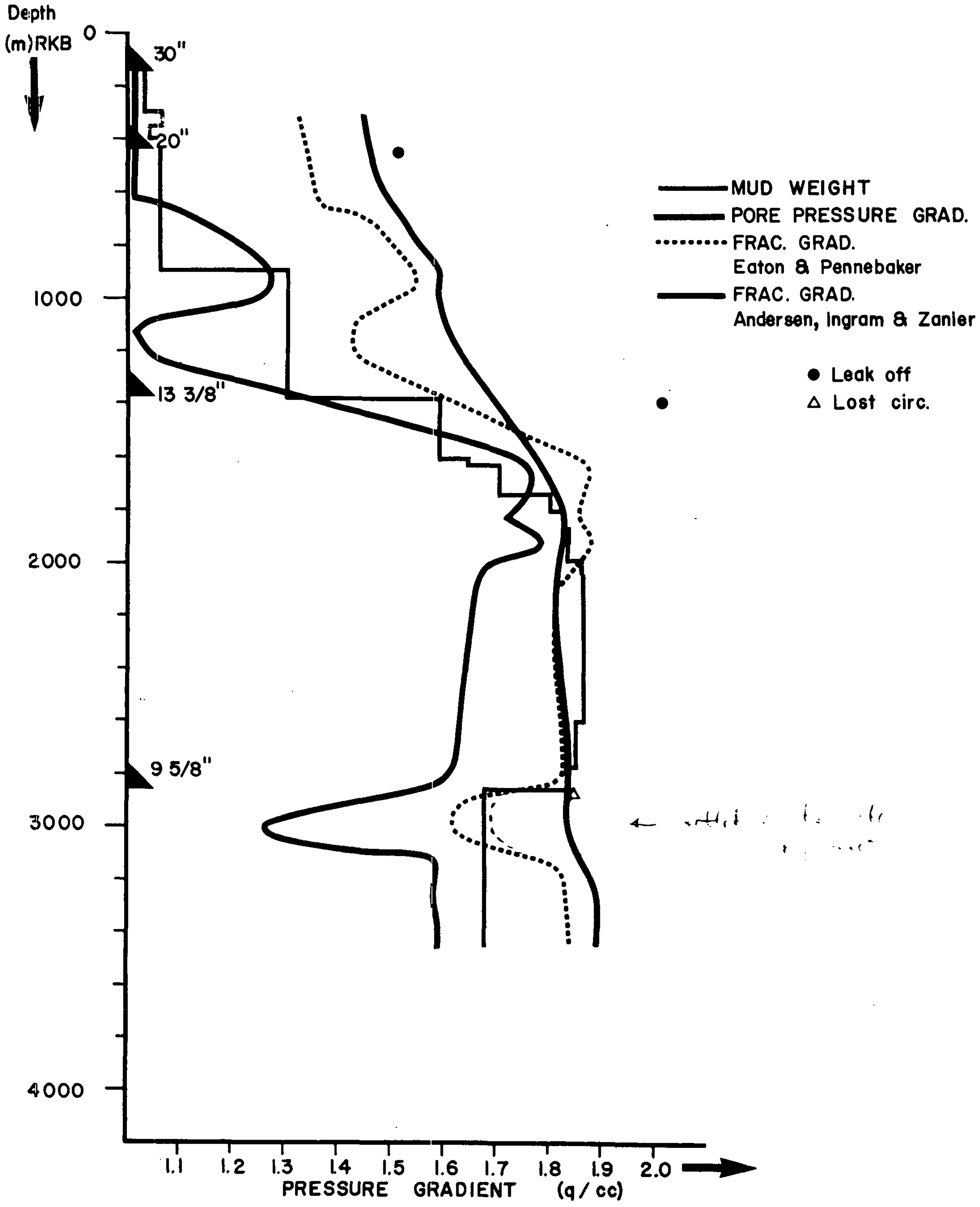


Fig. 29

ESTIMATED PORE PRESSURE & FRACTURE GRADIENTS-WELL 1/9-1.



ESTIMATED PORE PRESSURE & FRACTURE GRADIENT-WELL 1/9-2



Pore Pressure Predicton

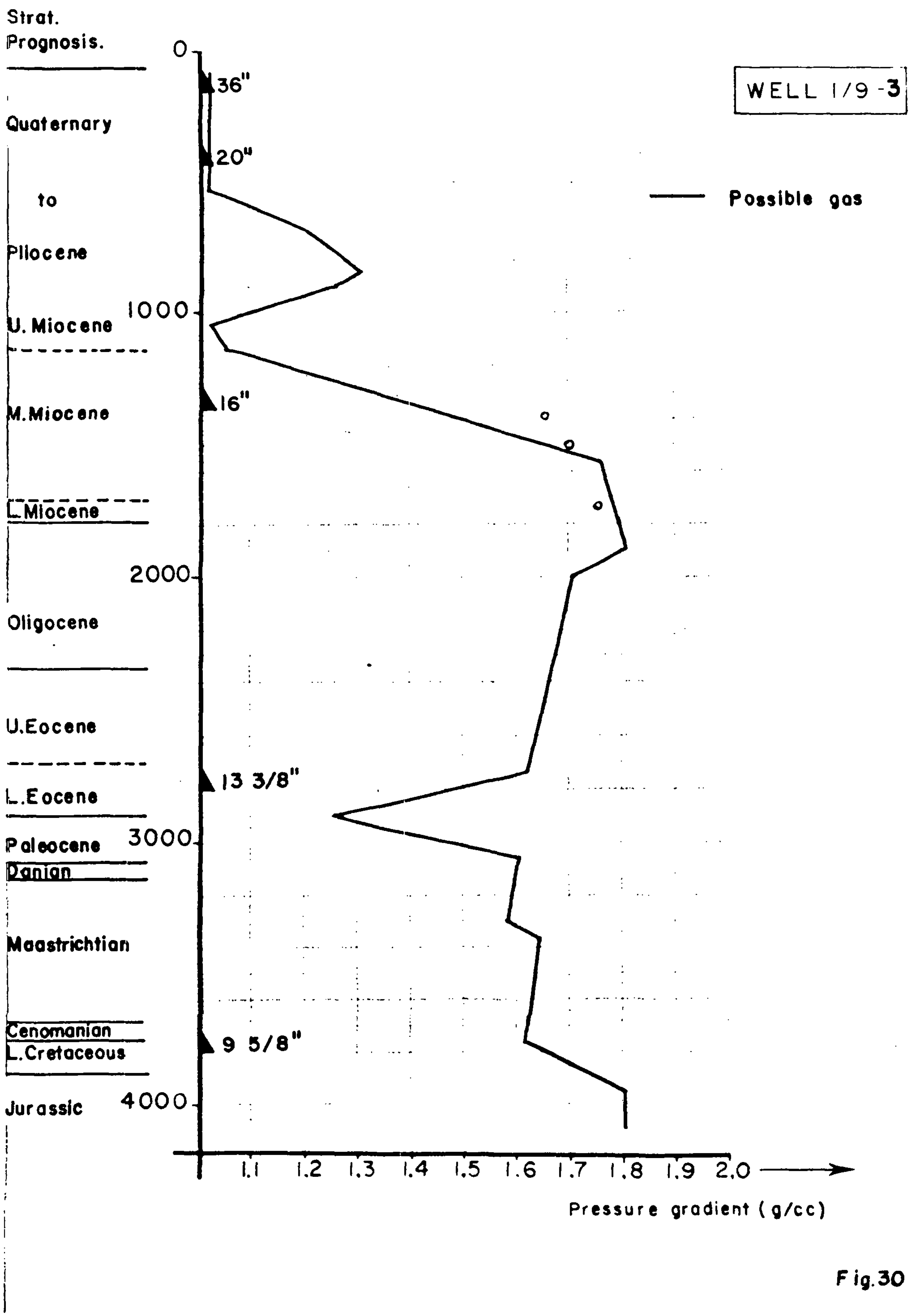


Fig.30

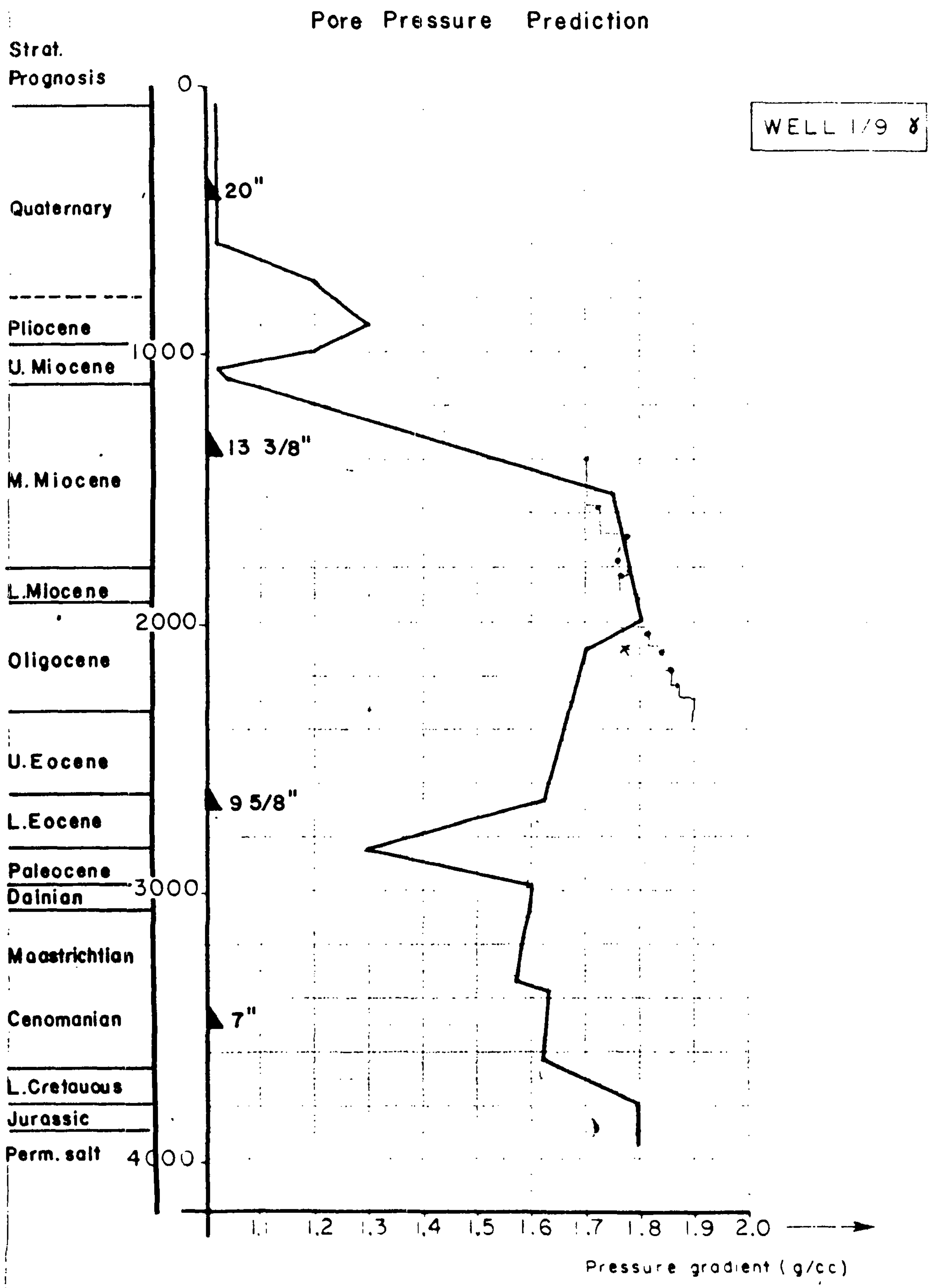

Pore Pressure Prediction
Strat. Prognosis
WELL 1/9 γ
Quaternary
Pliocene
U. Miocene
M. Miocene
L. Miocene
Oligocene
U. Eocene
L. Eocene
Paleocene
Dainian
Maastrichtian
Cenomanian
L. Cretaceous
Jurassic
Perm. salt
0
1000
2000
3000
4000
20"
13 3/8"
9 5/8"
7"
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 31

ST 02-PS.11.16-01
1/9-2

PORE PRESSURE AND FRACTURE GRADIENT ESTIMATES
FOR WELL 1/9-1 AND WELL 1/9-2

PORE PRESSURE GRADIENT PREDICTIONS
FOR WELL 1/9-3 AND WELL 1/9-Y 4

DONE BY PETROPHYSICAL SECTION
JULY 1977
ENG: WIGGO H. HOLM

CONTENTS

1. Abstract

Pore pressure gradients have been estimated for wells 1/9-1 and 1/9-2 by the use of sonic, density and conductivity logs. Based upon these estimates pore pressure gradient predictions for wells 1/9-3, 1/9-γ have been done.

Fracture gradients have also been calculated for wells 1/9-1 and 1/9-2 by the use of estimated overburden and pore pressure gradients.

X

2. HYDROSTATIC GRADIENT

It is not possible to calculate the formation water salinity from the SP-curve in Miocene down to Paleocene in wells 1/9-1 and 1/9-2.

The lack of good sand zones without gas makes it also difficult to calculate salinity from resistivity and porosity logs.

From the conductivity plots an increase in salinity can be seen from about 2000 m in Oligocene. The salinity increases with depth down to Paleocene.

In Maastrichtian the salinity is about 70000 ppm (1.02 g/cc at 240° F and 7000 psig). Further up in the wells it is not believed that the hydrostatic gradient is far from this gradient taking into account fresher formation water and decreasing pressure and temperature towards the upper parts of the wells.

An average hydrostatic gradient of 1.02 g/cc has been used in the pressure estimates.

3. OVERBURDEN GRADIENT

Figure 1. shows the integrated FDC-log versus depth for wells 1/9-1, 1/9-2, 30/19-2 (UK) and wells from the Ekofisk area.

The FDC- log for 1/9-1 is affected by gas in the interval 1000-2000 m and gives lower overburden than is expected to be met in wells 1/9-3 and 1/9-γ.

The overburden gradient used is about the same as for wells 1/9-2 and 30/19-2 above 1000 m approaching the overburden gradient for the Ekofisk area below 1000 m.

X

4. PORE PRESSURE GRADIENTS

Two methods have been used to calculate pore pressure from sonic and density logs. (see Appendix A)

1. The Equivalent Depth Method.
2. The Compaction Expont Method

An attempt has been made to establish normal pressure trend lines on a conductivity plots and to calculate pore pressure from Compaction Exponent Method.
Clay porosity has been plotted versus depth and a clay porosity pore pressure gradient relationship has been made.

4.1 PORE PRESSURE ESTIMATES FROM SONIC LOG

A straight normal trend line was drawn through the normal pressured parts in the wells 1/9-1, 1/9-2. (Fig. 3 and 4) The above mentioned two methods was used to calculate pore pressure (fig. 14 and 21). The Compaction Exponent Method gives too low pressures in the upper parts of the overpressured zone and too high pressures in the lower parts. This is most probably due to the use of a straight trend line which gives too low normal log values in the upper overpressured parts of the wells and too high values in the lower parts.

The Equivalent Depth Method gives the best estimates of Pore Pressure gradients when using straight trend lines.

4.2 PORE PRESSURE ESTIMATES FROM DENSITY LOG

The FDC logs were plotted on lin-lin grids and a straight trend line was drawn through normal pressured regions in wells 1/9-1 and 1/9-2.

The Compaction Exponent Method was used with an exponent equal to 10. The two methods did not give the same gradients in Miocene and a normal trend shift for Miocene was established. The resulting pore pressure gradients are shown in fig. 15 and 22.

4.3 PORE PRESSURE ESTIMATES FROM CONDUCTIVITY LOG

An attempt was made to establish some normal trend lines on the conductivity plot so that the pore pressures calculated from the Compaction Exponent Method with an exponent equal to 1.2 would give a good fit to pressures calculated from sonic and density logs. A formation water salinity change in the middle of Oligocene gives a trend line shift. The new trend indicates that the normal conductivity should increase with depth. This is not what normaly is expected and the reason is an increasing formation salinity with depth below 2000 m.

The resulting pore pressure gradients can be seen in fig. 16 and 23.

4.4 PORE PRESSURE ESTIMATES FROM CLAY POROSITY

Clay porosity (Φ clay) was calculated from sonic and density logs and plotted versus depth. The shales are believed to consist of a mixture of sand, clay and water. The log respons in dry sand and clay was selected to be:

ρbsand = 2.65 g/cc Δt sand = 55.5 μs/ft
ρbclay = 2.85 g/cc Δt clay = 140 μs/ft

The respons in formation water:

ρbwater = 1.02 g/cc Δt water = 189 μs/ft

The quantitative calculation of sand and clay fractions and the clay porosity are not believed to be very reliable. The relative changes will be most important in the pore pressure calculations.

The clay porosity plotted versus depth for 1/9-1 and 1/9-2 can be seen on fig. 9 and 10. The plot for 1/9-2 seems to be fairly good but the plot for 1/9-1 are influenced by the gas effect on log responses. The correlation of the 1/9-2 plot with sonic and density plot and also the D_c-exponent is good. A straight normal trend line was drawn through the regions which are believed to be normal pressured. A relationship between the pore pressure gradient and Φclay/Φclay normal was then established based on the pore pressures calculated from sonic and density logs. This relationship can be seen in fig. 17. The calculated pore pressure gradients can be seen in fig. 18 and 24.

4.5 CONCLUSION PORE PRESSURE GRADIENT ESTIMATES

The estimated pore pressure gradients for well 1/9-1 and well 1/9-2 are shown in fig. 13 and 20. They are based upon the calculations from sonic and density logs using the Equivalent Depth Method.

The quantitative pore pressure estimates above 1000 m are more uncertain in both wells due to the greater scattering in the data. The clay porosity indicates overpressure in well 1/9-1 but not in 1/9-2 above 1000 m. All the other logs indicate overpressure above 1000 m. The estimated pore pressure gradient seems to increase more rapidly up to maximum pressure gradient than reflected in the mud weights used. (fig. 12 and 19), which may indicate that parts of the two wells are drilled under-balanced. On the other hand, the maximum mud weight used on well 1/9-2 seems to be slightly too high.

5. FRACTURE GRADIENT ESTIMATES

The fracture gradients for wells 1/9-1 and 1/9-2 are calculated by using two methods (see Appendix B):

1. Eaton & Pennebaker
2. Andersen, Ingram & Zanier.

8

In method 2 the shale porosity used in the formula was calculated from the sonic-density crossplot using the same matrix and fluid responses as given in 4.4. In fig. 25 and 26 the results from the calculations are presented using different but constant Poissons ratios. The discreapancy is big in normal pressured zones because method 1 is primarly depending upon the Pore Pressure gradient while method 2 are more depending upon the overburden gradient.

A variable Poissons ratio with depth (see fig. 27) will give a better fit between the two methods. Method 1 reflects the lower fracture gradients in normal pressured zones much more than method 2.

It should be emphasized that the fracture gradients in these calculations relates to silty or sandy formation or a relatively weak formation with high quarts content. Shales with low quartz content have higher fracture gradients, and act more elastic than silty or sandy zones.

From the pore pressure estimate an abrupt decrease in pore pressure is seen in Lower Eocene and in Paleocene.

From a calculation of quartz, clay and porosity content (see fig. 29) Well 1/9-2, intervall 2700 m - 2900 m, it can be seen that a relatively high quartz and low clay mineral content is seen were the 9 5/8" csg shoe landed (2856 m). In well 1/9-2 a lost return problem could probably have been avoided if the casing shoe had been set above 2800 m where the pore pressure gradient is higher, and the formation has a higher fracture gradient. The fracture gradient calculations indicates that the fracture gradients further into Paleocene are lower than measured from leak offs at the 9 5/8" csg shoe in wells 1/9-1 and 1/9-2, (1.84 g/cc) because the pore pressure still decreases when drilling into Paleocene.

5.1 CONCLUSION ON FRACTURE GRADIENT ESTIMATES

The calculated fracture gradients for wells 1/9-1 and 1/9-2 indicates approximately the strength of silt or sand formations with the same pore pressures calculated for the two wells.

The fracture gradients should be considered to be a qualitative indication of how the fracturing strength changes with overburden and pore pressure in such weak formations, more than to be a quantitative estimate of the fracture gradients for the two wells.

6. Pore pressure prediction, well 1/9-3

The pore pressure expected to be met in well 1/9-3 is shown in fig. 30. The estimate is based upon the pressures calculated for wells 1/9-1 and 1/9-2 and adjusted according to stratigraphic depth prognosis.

Two bright spots on the seismic indicate possible gas at 560 m and 1760 m. The mud weight should be increased to 1.3 g/cc when drilling out the 20" csg.

The rapid pore pressure gradient build up calculated in well 1/9-1 and 1/9-2 indicates that mud weight should be increased to 1.8 at 1500 m and increased to 1.82 - 1.83 at 1800-1900 m.

The pore pressure decrease in Lower Eocene is expected at 2760 m. The 13 3/8" csg should be landed above 2760 m in the higher pore pressure gradient zone to avoid lost circulation problems.

A pressure gradient increase should be expected in Lower Cretaceous (1.7-1.75g/cc) and Jurassic (1.75-1.85g/cc) based upon experience from wells drilled to Jurassic in the Eldfisk and Valhall field.

Care should be taken not to increase the mudweight above 1.75 - 1.78 g/cc before setting casing in Lower Cretaceous due to the weak zones in Lower Eocene, Paleocene.

7. Pore Pressure prediction 1/9-γ

The pore pressure gradient expected to be met in well 1/9-γ is shown in fig. 31. The pressure estimate is based upon the pressures in wells 1/9-1 and 1/9-2, and adjusted according to stratigraphic depth prognosis.

Bright spots on the seismic, indicating possible gas, is seen in the intervals 1100 m - 1300 m and 1630m - 2100 m.

Rapid pore pressure build up below the pressure transition zone means that mud weight should be increased to 1.8 g/cc before 1500 m and then gradually increased to 1.82 - 1.83 g/cc.

The 9 5/8" csg should not be landed much lower than the stratigraphic prognosis showing Top Lower Eocene (2635 m) to avoid lost cirkulation problems.

Again a pore pressure gradient increase should be expected when drilling into Lower Cretaceous and Jurassic.

8. Conclusion

From the pore pressure gradient estimates it seems that the mud weight should be increased to 1.3 g/cc below the 20" csg when drilling out 13 3/8" csg.(or 16" csg. in 1/9-3) mud weight should be increased relatively fast to 1.8 g/cc and then gradually increased to 1.82 - 1.83 g/cc.

Pore pressure gradients of 1.7 g/cc up to 1.75 g/cc is expected in Lower Cretaceous and 1.75 g/cc up to 1.85 g/cc in Jurassic.

The fracture gradient calculations show weak zones in Lower Eocene and Paleocene. Casing should be set before drilling into these weak zones about the Top of Lower Eocene.

9. APPENDIX A

Pore pressure gradient calculations are based upon the following two methods:

1. The Equivalent Depth Method

PP	=	$PO - (PO-PN)\ D_E/D_I$
PP	=	Pore pressure gradient (q/cc)
PO	=	Overburden gradient (g/cc)
PN	=	Hydrostatic gradient (g/cc)
D_E	=	Equivalent Depth (m)
D_I	=	Depth of interest (m)

2. The Compaction Exponent Method

PP	=	$PO - (PO-PN)\ (LN/L)^{EXP}$
LN	=	Normal log respons in shales
L	=	Log respons in shales
EXP	=	Exponent depending on the log used
EXP	=	3 for the sonic log
EXP	=	10 for the density log
EXP	=	1.2 for the conductivity log

10. APPENDIX B

Fracture gradients was estimated using two different methods.

1. Eaton & Pennebaker

$$PFT = \frac{\mu}{1-\mu} (PO-PP) + PP$$

where

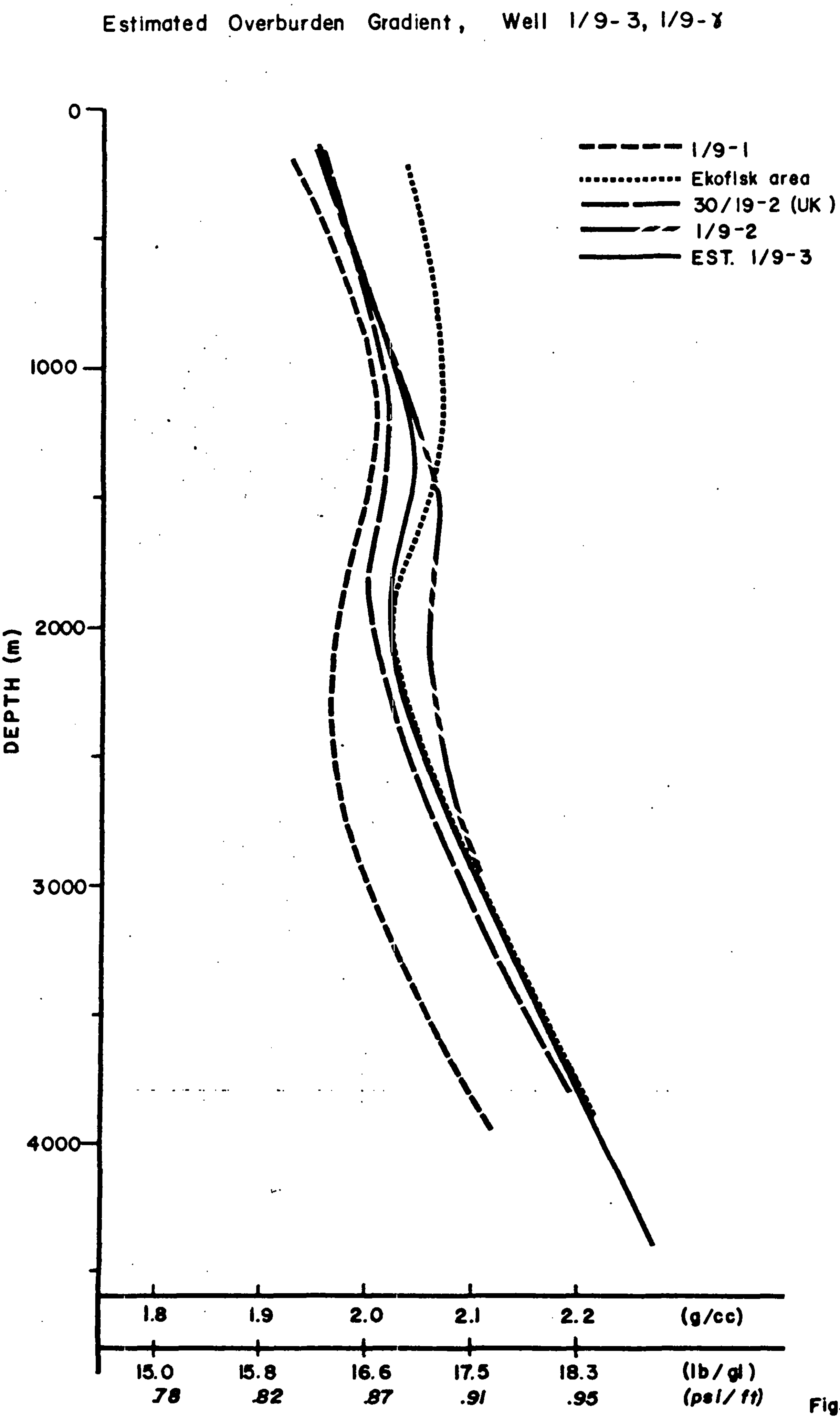
PF	=	Fracture gradient (g/cc)
PO	=	Overburden gradient (g/cc)
PP	=	Pore pressure gradient (g/cc)
μ	=	Poissons ratio

2. Andersen, Ingram & Zanier

$$PF = \frac{2\mu}{1-\mu} PO + \alpha \frac{1-3\mu}{1-\mu} \cdot PP$$

where

α	=	$1 - (1 - \Phi)$
Φ	=	porosity in shales calculated from density and sonic log



Estimated Overburden Gradient, Well 1/9-3, 1/9-γ
0
1000
2000
3000
4000
DEPTH (m)
1/9-1
Ekofisk area
30/19-2 (UK)
1/9-2
EST. 1/9-3
1.8
1.9
2.0
2.1
2.2
(g/cc)
15.0
15.8
16.6
17.5
18.3
(lb/gl)
.78
.82
.87
.91
.95
(psi/ft)

Fig. 1

STRATIGRAPHIC PROGNOSIS

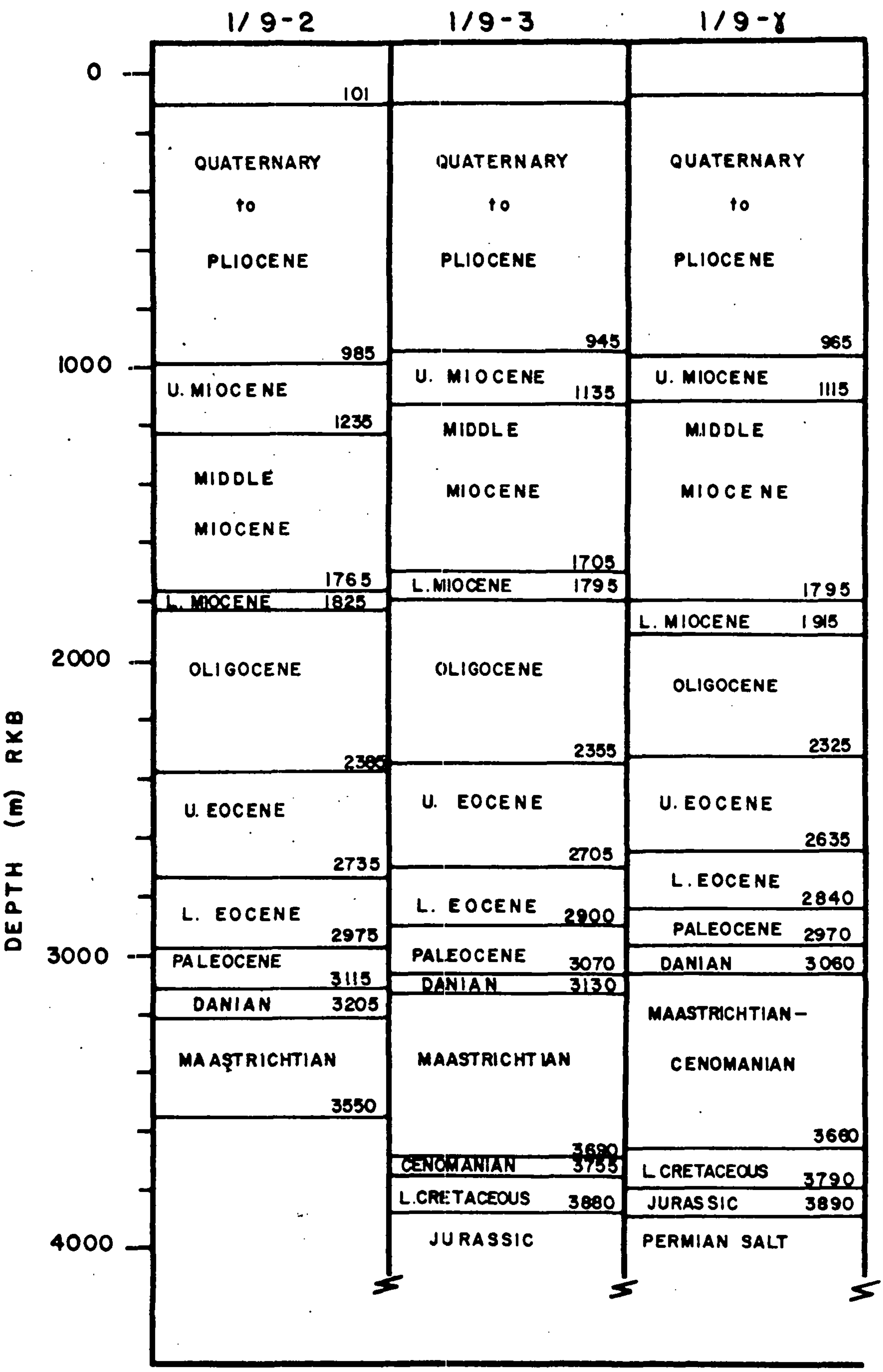
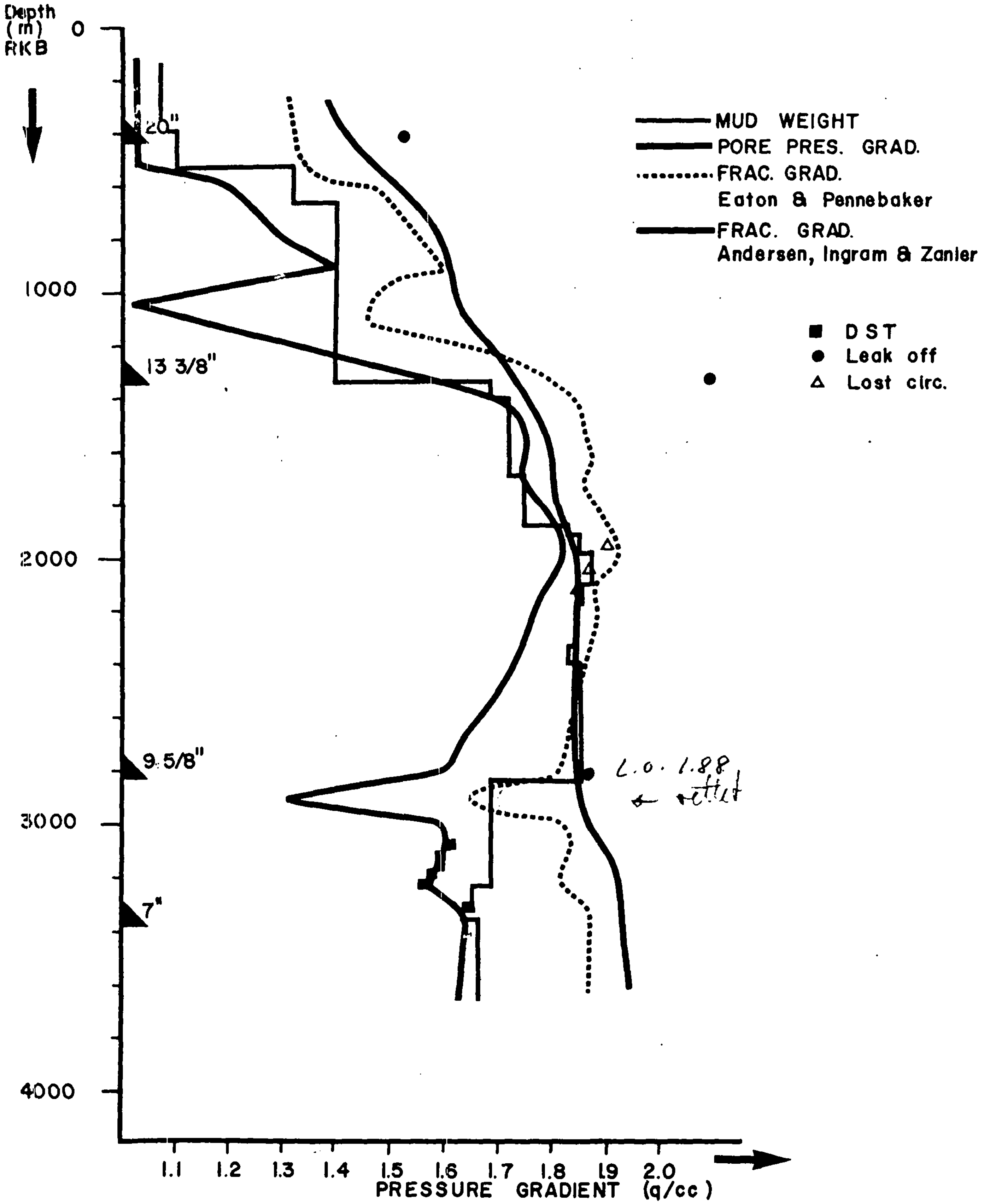
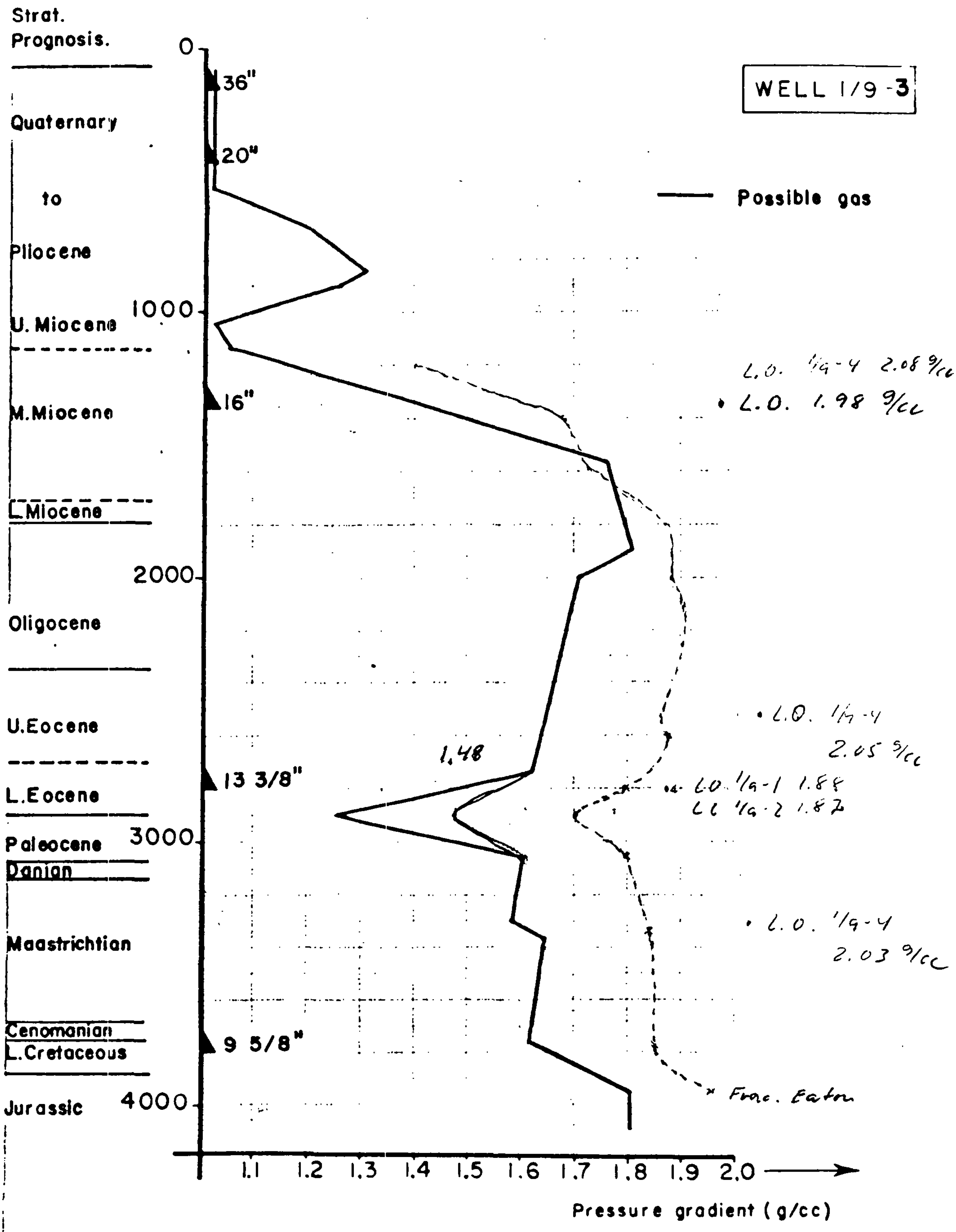


Fig. 2

ESTIMATED PORE PRESSURE & FRACTURE GRADIENTS-WELL 1/9-1.



Pore Pressure Predicton



1/9-1 res. trykk 1.56

Fig.30

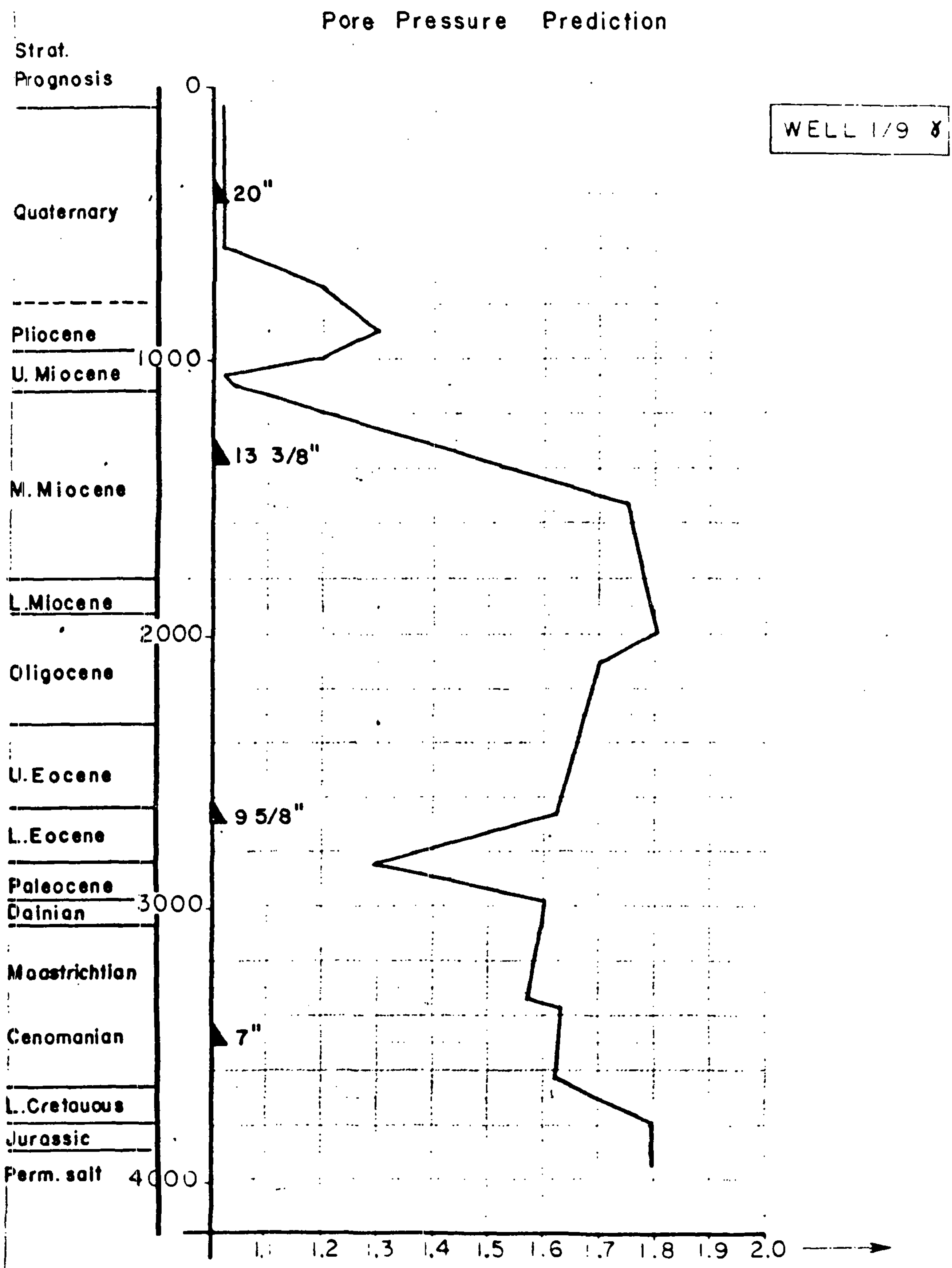

Pore Pressure Prediction
Strat. Prognosis
WELL 1/9 γ
0
1000
2000
3000
4000
Quaternary
Pliocene
U. Miocene
M. Miocene
L. Miocene
Oligocene
U. Eocene
L. Eocene
Paleocene
Dainian
Maastrichtian
Cenomanian
L. Cretaucus
Jurassic
Perm. salt
20"
13 3/8"
9 5/8"
7"
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
1.9
2.0
Pressure gradient (g/cc)

Fig. 31