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EAST MEREENIE No. 4 SPECIAL CORE ANALYSIS TESTS ON SAMPLES FROM THE ORDOVICIAN (PACOOTA) SANDSTONE RESERVOIR

by

B.A. McKAY

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MINERAL RESOURCES BRANCH

PETROLEUM TECHNOLOGY SECTION

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INTRODUCTION

Oil Permits Nos 43 and 56 Northern Territory, were issued to Magellan Petroleum Corporation and United Canso Oil & Gas Ltd in 1960 and 1961 respectively. Exoil Pty Ltd., Transoil Pty Ltd, Farmout Drillers N.L. and Krewliff Investments Pty. Ltd., became farm-in partners with Magellan and United Canso in these permits, with Exoil acting as operator in a subsequent drilling programme.

Mereenie No. 1, the first well drilled by the Group, was located approximately on the crest of a large anticline, which lies across the common boundary of the two permits. This well proved the existence of hydrocarbons in the structure, and four additional appraisal/development wells were subsequently drilled.

East Mereenie No. 4 was the sixth well in the field. It was drilled to test the oil potential of the Pacoota formation, in addition to evaluating the hydrocarbon potential of the underlying Cambrian section.

The well was spudded in April, 1967, and drilled to a total depth of 8750 feet in July 1967. Three separate strings of casing were set from surface to 134 feet, 2205 feet and 5265 feet respectively.

During open hole tests in May and June, the well produced gas from the Stairway formation, and gas and oil from the Pacoota formation. Considerable formation damage occurred in the oil producing zones in the Pacoota. However, subsequent work (fracturing) was carried out and oil productivity considerably improved.

The drilling operation at East Mereenie No. 4 well was not eligible for payment of subsidy under the Petroleum Search Subsidy Act. However, core samples from this well were made available to the Petroleum Technology Laboratory of the Bureau of Mineral Resources, to supplement studies made on a previous well in the field. (East Mereenie No. 1).

This report contains results of the special core analysis study in the East Mereenie No. 4 well. The study included porosity, permeability, fluid imbibition, capillary pressure and resistivity tests conducted in samples from a gas and oil producing Ordovician sandstone.

PROCEDURE AND APPARATUS.

The tests were conducted on three separate sets of plugs from four preserved cores. These sets were composed of sixteen $1\frac{1}{8}$-inch diameter plugs for fluid imbibition and resistivity tests, sixteen $1\frac{1}{8}$-inch diameter samples for porosity and permeability (gas and liquid) tests, and sixteen $\frac{3}{4}$-inch diameter samples for mercury injection capillary pressure tests.

All core samples were preserved by canning "fresh" cores at the wellsite; for test purposes therefore, the imbibition plugs were selected first. These were drilled parallel to the bedding, using kerosene as the diamond bit coolant. They were trimmed to approximately $1\frac{1}{4}$ inches in length, then placed in refined oil (Soltrol-C) until testing to maintain the indigenous wetting characteristics. The remaining samples were drilled using water as the coolant, trimmed to approximately $1\frac{1}{4}$ inches, extracted with toluene and oven-dried for 24 hours at 110°C.

The imbibition tests were conducted in the following manner. Each of the preserved plugs was first flushed with several pore volumes of oil (Soltrol-C) in a flexible sleeved Hassler cell, to ensure residual water saturation was established in the samples. They were then immersed in water and the amount of oil displaced by water from the samples over a seven day period was noted.

When the imbibition tests had been completed, the same samples were used in the determination of resistivity and formation factors. They were first thoroughly extracted with toluene, and then oven dried at 110°C for 24 hours. The samples were then saturated with 5% NaCl brine and formation resistivity tests were conducted in a Core Laboratories type core resistivity apparatus (Figure 19). This equipment consists of a dip-cell for measuring the resistivity of formation water, and a core sample holder with spring mounted electrodes for determining core resistivity. A formation factor was calculated for each sample from the data, by expressing the core resistivity (in ohm meters) as a fraction of the formation water resistivity. Formation factors in turn were correlated with sample porosity; a cementation factor for the zone was derived from the plotted slope of the above correlation.

The second set of core plugs was now used for gas and liquid permeability determinations. Prior to these tests, porosity was measured in a Ruska-type mercury porosimeter, and single-phase absolute permeability to dry nitrogen was measured, in a rubber sleeve Hassler cell.

Equivalent liquid permeability tests were then conducted, to determine the flow capacity through the sample to a non-reactive liquid. Using nitrogen as the flowing phase, the permeability of each sample was measured at several (four) different mean, but constant differential pressures. The four permeability values for each sample were then plotted as a function of the reciprocal mean pressure, giving the non-reactive liquid permeability (Klinkenberg).

Separate liquid permeability tests were then performed on each of the samples to determine its compatability with various fluids. These were conducted using a light refined oil (Soltrol-C), 5% Na Cl brine and fresh water as the flowing fluids respectively. Each of the tests was preceded by extraction and drying of the samples; dry weight/dry air permeability was checked for continuity between tests.

Two-phase liquid flow tests were also conducted on the samples. These were carried out to investigate the effects of mud filtrate invasion around the well bore during drilling and completion operations, and subsequent flushing of the invaded zone by oil during production.

For these tests, the samples were initially saturated with Soltrol-C, flushed in a Hassler cell to residual oil saturation by "invading filtrate" water, and finally flushed to residual "invading" water saturation with oil (Soltrol-C). Permeability with respect to fresh water at residual oil saturation, and to oil at residual fresh (invasion) water saturation, was determined after no more displaced phase was apparent in the effluent.

Mercury injection capillary pressure tests were then conducted using the set of $\frac{3}{4}$-inch core plugs. These tests were carried out in a Ruska-type mercury injection apparatus using the Purcell (1) method, whereby mercury, representing the saturating non-wetting phase, is injected into the samples at increasing pressure "step ". The quantity of mercury injected is recorded after volume stabilization at each step is reached; capillary pressure curves are then constructed from the completed test results after a maximum pressure (1400 psia in these tests) has been attained.

Pore size distribution values were calculated from the above mercury injection capillary pressure tests, using the formula $r = \frac{2\,\gamma\,\cos\theta}{\Delta p}$. Average pore "throat" radii for the corresponding saturation pressure intervals were calculated using values of 480 dynes/cm for mercury surface tension (γ), and 140° as the mercury-rock contact angle (θ).

DISCUSSION OF RESULTS

The results of the foregoing tests are listed as follows:

(i) Tables I and II-single and two-phase liquid permeability tests;

(ii) Table III- water/oil imbibition results;

(iii) Table IV- porosity, absolute permeability to nitrogen and formation factors;

(iv) Table V- pore throat radius for corresponding saturation-pressure intervals.

Figures 1-16 present the results of the mercury injection capillary pressure tests; Figure 17 presents the Klinkenberg test results; Figure 18 shows the core resistivity apparatus, while Figure 19 shows the graphical correlation between porosity and formation factor for the samples. The positions of the various samples are referred on the electrical log shown in Figure 20.

The liquid permeability test results shown in Table I indicate the compatability between the sample material and the single-phase fluids (oil, brine and fresh water) used in the flow tests. No severe reductions in permeability to single-phase flow were noted, and all flow rates in each sample were generally quite stable when testing was completed.

A very different situation exists under two-phase liquid flow conditions, as noted in Table II. In the case of a well bore which has been invaded with mud, reductions of between 90% and 95% in permeability to fresh water at residual oil saturation are noted. However, flow capacity was considerably improved by reflushing the water-invaded cores with oil. Oil was displaced through the samples (10 to 15 pore volumes) until no more invasion water was apparent in the effluent; permeability to oil was found to be still increasing when testing was completed.

These results suggest that although residual water saturation had apparently occurred in the samples (taking into account capillary end effects), rearrangement of the saturation distribution to oil and water was still taking place, decreasing "drag" and improving flow capacity to oil. It is probable that, provided sufficient pressure draw-down could be obtained through production around a "water-damaged" well bore, similar conditions could be expected to occur in the reservoir.

The formation factor/porosity plot (Figure 19) for these samples indicates a good correlation between the two parameters. Point scattering was limited, although sample porosity covered a fairly wide range (5%-15%).

However, an interesting point occurs when the cementation factor is determined from the above correlation. This factor, which is derived from the slope of the plot of formation factor against porosity, was found to be 1.76.

Using the Archie (2) and Pirson (3) classification system, a cementation factor of 1.76 places the lithology of the formation between slightly and moderately-well cemented, with porosities ranging up to 20%. This is not entirely consistent with the lithology (well consolidated sandstone) and the measured porosity values (Table IV) of the samples.

Because of this discrepancy, another suite of $1\frac{1}{8}$-inch diameter samples was selected and tested for resistivity, using a brine of lower salinity (2% Na Cl). (Archie has shown that the formation factor is constant for waters of varying salinities). Although there was a slight increase in point scattering, the formation factor/porosity plots for the two sets of samples were almost identical.

An examination of the samples shows that some contain significant amounts of pyrite. Although discontinuous, it is possible that the pyrite could have some bearing on the electrical conductivity, which appears to be higher than normal for this type of core material. This anomaly can be better evaluated by testing the resistivity of a greater number of samples from this formation.

The water-oil imbibition tests, as shown in Table III, indicate that all samples were originally water-wet. The maximum amount of oil displaced by water from the samples in these tests was 33% of pore volume; this represents the most permeable group.

The samples used in the imbibition tests were sealed from wellsite to laboratory to preserve the naturally occurring wetting characteristics of the rock. The measured values should therefore fairly closely duplicate the wetting conditions in this reservoir.

Investigations (4) have shown that wettability is intimately related to capillarity, which in turn controls the microscopic fluid saturation and distribution in a reservoir. In addition, under water-wet conditions, measured oil recoveries obtained from preserved cores by imbibition have been shown (5) to agree closely with those obtained by water drive. It can therefore be assumed that wetting tests performed in the East Mereenie No. 4 samples will give some measure of the displacement efficiency of oil by water in this particular (water-wet) formation.

The mercury injection capillary pressure tests were essentially a repeat of test results shown in East Mereenie No. 1 (6). The more permeable samples were typified by low threshold and low irreducible water saturations. Although not as pronounced, the capillary curve profiles and pore size values again essentially indicated a fairly well-sorted pore distribution; curve configuration was generally characterized by low long slopes in relation to the abscissae, rapidly changing and becoming asymtotic to the ordinate axes at irreducible water saturation. A similar, but less pronounced trend was again revealed in those samples having a lower permeability (less than 5 md).

CONCLUSIONS

Special core analysis tests conducted on core samples from the East Mereenie No. 4 well have shown the following:

1. Porosity and permeability values of the reservoir samples tested were generally low; however, as in tests on East Mereenie No. 1, good reservoir characteristics were found in samples having a permeability greater than 10 md.

2. Single-phase liquid permeability tests revealed the sample material to be generally compatable with oil, brine, and fresh water, and no severe reductions in flow capacity were noted. However, two-phase flow tests of oil and water simulating well bore damage by water invasion revealed marked reduction in flow capacity. Permeability was partially restored by flushing the damaged samples with oil; improvement continued beyond apparent residual water saturation, probably due to a continuing rearrangement of the two-phase fluid saturation distribution in the samples.

3. Correlation between the formation factor and porosity in these samples was good; the resulting cementation factor calculated from two separate resistivity tests was found to be 1.76. However, this factor is not entirely in accord with published values on rock of similar porosity/lithology. The reason for resistivity values apparently lower than normal is not clear; additional sample testing is recommended to substantiate the cementation factor value.

4. Wetting tests conducted on preserved samples revealed the formation to be moderately water-wet. Maximum oil displacement by water imbibition in the more permeable samples (up to 50 md.) was 33% of pore volume. Displacement efficiency of oil by water imbibition in samples having low flow capacity (less than 1 md) was poor.

5. Mercury injection capillary pressure tests indicated low initial injection (threshold) pressures and low residual water saturations in samples having good permeability. Capillary curve profiles and calculated pore size generally revealed a well sorted pore distribution.

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5.	MOORE, T.F. SLOBOD, R.L.	"Displacement of Oil by Water - effect of Wettability, Rate, and Viscosity on Recovery". Volume 20 Producers Monthly, 1956.
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TABLE 1.

Well Name and Number	Sample Depth (Feet)	Core Number	Porosity % Bulk Volume	Permeability to dry Nitrogen (Md.)	Equivalent liquid Permeability (Md.)	PERMEABILITY TO SOLTROL-C		PERMEABILITY TO 5% BRINE		PERMEABILITY TO FRESH WATER.	
						(Md.)	% Equivalent Liquid Permeability	(Md.)	%Equivalent Liquid Permeability	(Md.)	%Equivalent Liquid Permeability
East Mereenie No. 4.	4196	1	5.3	0.61	-	0.23		0.29	-	0.59	-
"	4201	1	6.0	0.57	-	0.19	-	0.32	-	0.36	-
"	4608	2	10.5	0.63	-	0.33	-	0.19	-	0.19	-
"	4613	2	14.3	51	47	41	87%	27	57%	21	45%
"	4618	2	14.5	44	36	37	100%	31	86%	20	56%
"	4625	3	10.9	14	11	9.8	89%	8.1	73%	7.2	65%
"	4630	3	8.2	16	12	13	100%	9.8	81%	8.6	72%
"	4635	3	8.7	6.1	4.5	4.3	95%	2.8	62%	2.8	62%
"	4702	4	9.0	1.0	-	0.74	-	0.55	-	0.60	-
"	4710	4	10.4	22	17	16	94%	15.2	89%	21	100%
"	4712	4	10.5	28	23	18	78%	19.4	84%	17	74%
"	4718	4	5.9	0.19	-	0.13	-	0.063	-	0.069	-
"	4731	4	8.0	0.52	-	0.36	-	0.18	-	0.19	-
"	4742	4	11.5	49	44	41	93%	29	65%	30	68%
"	4747	4	6.9	0.76	-	0.38	--	0.22	-	0.22	-
"	4752	4	9.3	6.1	4.0	3.6	90%	3.8	95%	3.6	90%
					Average		92%		77%		70%

TABLE II

Well Name and Number	Sample Depth (Feet)	Porosity (% Bulk Volume)	Permeability to Dry Nitrogen (Md)	Equivalent Liquid Permeability (Md)	Permeability to Oil (Soltrol-C) (Md)	PERMEABILITY TO FRESH WATER AT RESIDUAL OIL SATURATION (Md.)	PERMEABILITY TO FRESH WATER AT RESIDUAL OIL SATURATION % Equivalent Liquid Permeability	PERMEABILITY TO OIL AT RESIDUAL INVASION WATER SATURATION (Md.)	PERMEABILITY TO OIL AT RESIDUAL INVASION WATER SATURATION % Equivalent Liquid Permeability
East Mereenie No. 4	4196	5.3	0.61	-	0.23	-	-	-	
"	4201	6.0	0.57	-	0.19	-	-	-	
"	4608	10.5	0.63	-	0.33	-	-	-	
"	4613	14.3	51	47	41	1.8	3.8%	19	40.0%
"	4618	14.5	44	36	37	2.2	6.1%	12	33.4%
"	4625	10.9	14	11	9.8	0.50	4.5%	3.1	28.2%
"	4630	8.2	16	12	13	0.76	6.3%	4.9	40.8%
"	4635	8.7	6.1	4.5	4.3	0.30	6.6%	1.9	42.2%
"	4702	9.0	1.0	-	0.74	-		-	
"	4710	10.4	22	17	16	1.9	11.1%	7.7	45.2%
"	4712	10.5	28	23	18	2.2	9.6%	7.0	30.4%
"	4718	5.9	0.19	-	0.13	-		-	
"	4731	8.0	0.52	-	0.36	-		-	
"	4742	11.5	49	44	41	4.4	10.0%	10.8	24.5%
"	4747	6.9	0.76	-	0.38	-		-	
"	4752	9.3	6.1	4.0	3.6	0.32	8.0%	2.5	62.5%

TABLE 111

Well Name and Number	Core Number	Sample Depth (Feet)	Porosity (% Bulk Volume)	Dry-Air Permeability (Md.)	Saturating Medium	VOLUME OF WATER IMBIBED % PORE VOLUME			
						After 1 Day	After 2 Days	After 3 Days	After 7 Days
East Mereenie No. 4	1	4196	5.3	0.61	SOLTROL-C	TRACE	TRACE	TRACE	TRACE
"	1	4201	6.0	0.57	"	Nil	TRACE	TRACE	TRACE
"	2	4608	10.5	0.63	"	Nil	TRACE	TRACE	1
"	2	4613	14.3	51	"	24	26	26	26
"	2	4618	14.5	44	"	31	31	33	33
"	3	4625	10.9	14	"	10	13	13	13
"	3	4630	8.2	16	"	8	10	12	12
"	3	4635	8.7	6.1	"	6	12	14	16
"	4	4702	9.0	1.0	"	2	2	4	9
"	4	4710	10.4	22	"	11	12	14	17
"	4	4712	10.5	28	"	13	18	21	24
"	4	4718	5.9	0.19	"	2	2	5	5
"	4	4731	8.0	0.52	"	8	12	14	14
"	4	4742	11.5	49	"	13	21	22	32
"	4	4747	6.9	0.76	"	7	11	11	11
"	4	4752	9.3	6.1	"	15	15	18	21

TABLE IV

CORE NUMBER	SAMPLE DEPTH (Feet)	PERMEABILITY TO DRY NITROGEN (Md.)	POROSITY (% Bulk Volume)	FORMATION FACTOR
1	4196	0.61	5.3	156
1	4201	0.57	6.0	130
2	4608	0.63	10.5	55
2	4613	51	14.3	27
2	4618	44	14.5	35
3	4625	14	10.9	56
3	4630	16	8.2	87
3	4635	6.1	8.7	80
4	4702	1.0	9.0	69
4	4710	22	10.4	56
4	4712	28	10.5	47
4	4718	0.19	5.9	145
4	4731	0.52	8.0	92
4	4742	49	11.5	38
4	4747	0.76	6.9	95
4	4752	6.1	9.3	72

TABLE V

AVERAGE PORE ENTRY RADIUS (MICRONS)

SATURATION - % PORE VOLUME								Sample Depth (Feet)
0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	
2.7	2.5	2.1	1.9	1.5	0.93	0.31		4196
	1.7	1.3	0.95	0.60	0.24			4201
1.3	1.1	0.97	0.81	0.62	0.42	0.24		4608
6.9	6.2	5.7	5.2	4.7	4.0	2.0	0.30	4613
7.1	6.8	6.6	6.2	5.6	5.2	3.7	0.97	4618
5.0	4.7	4.5	4.3	4.0	3.0	2.0	0.43	4625
	7.0	6.7	5.5	4.1	2.7	0.94	0.17	4630
7.1	5.3	4.1	3.0	2.1	0.99	0.35		4635
								4702
7.1	6.8	6.5	5.8	5.3	4.3	1.9	0.25	4710
	5.6	5.3	4.3	4.0	3.3	1.1	0.17	4712
		0.60	0.47	0.33	0.21			4718
	1.2	1.1	0.89	0.69	0.49	0.29		4731
		9.2	8.6	7.6	6.0	3.0	0.47	4742
	2.2	2.0	1.6	1.2	0.66	0.31		4747
			3.7	3.0	1.9	0.56		4752

FIGURE 1

MERCURY CAPILLARY PRESSURE

WELL NAME — E. MEREENIE No 4 SAMPLE DEPTH - 4196'

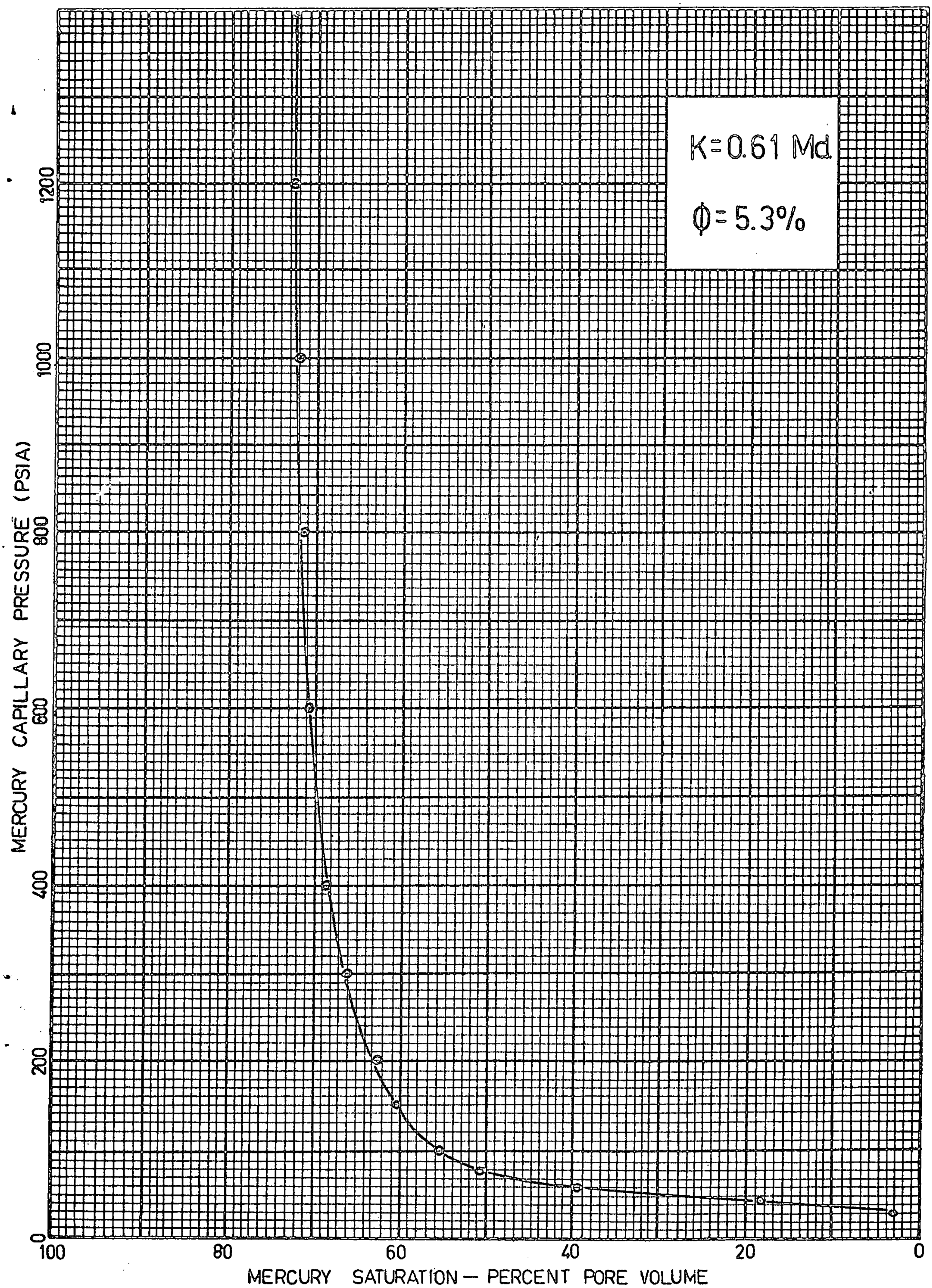

FIGURE 2

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH-4201

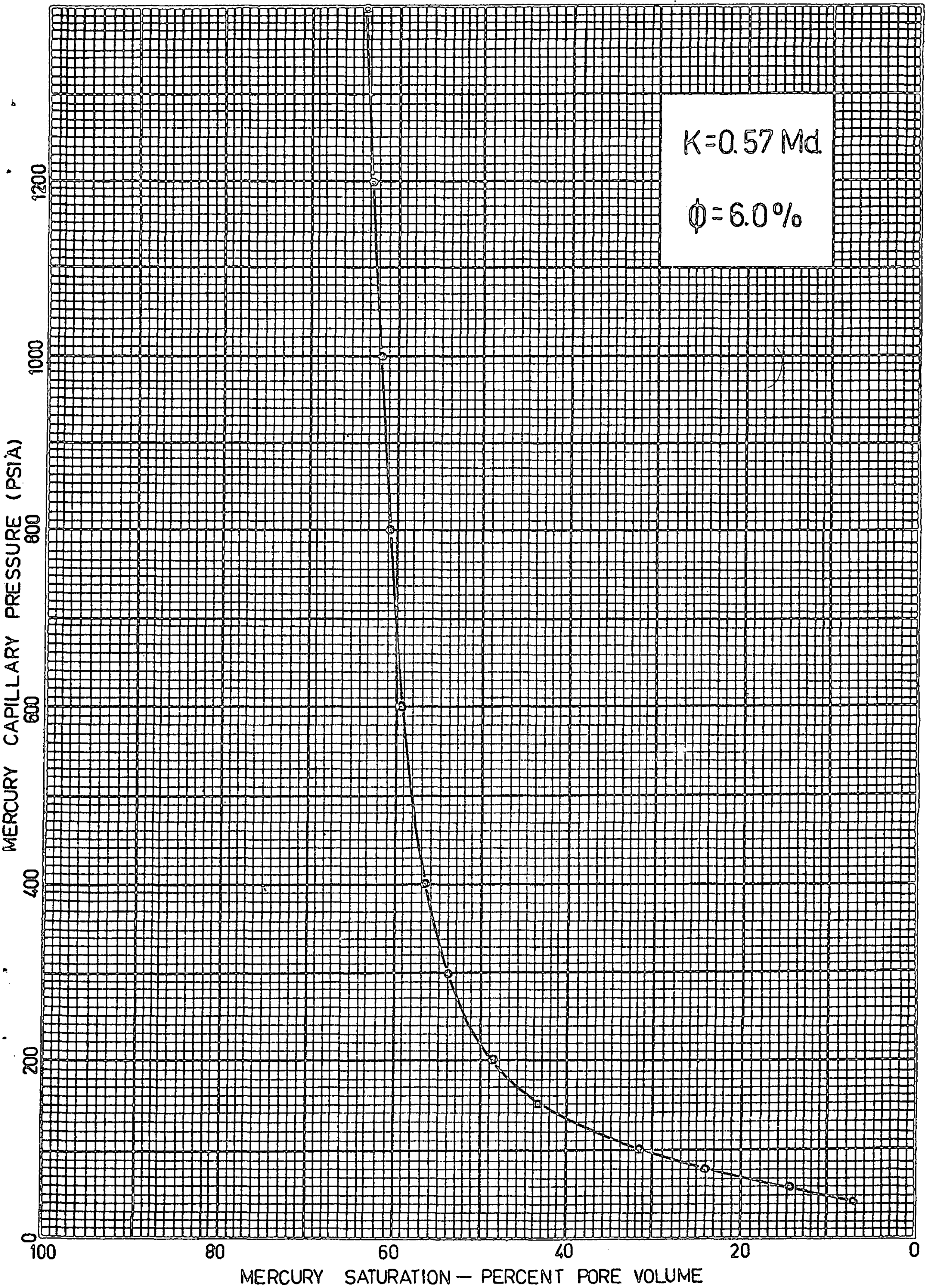

FIGURE 3

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4   SAMPLE DEPTH 4608

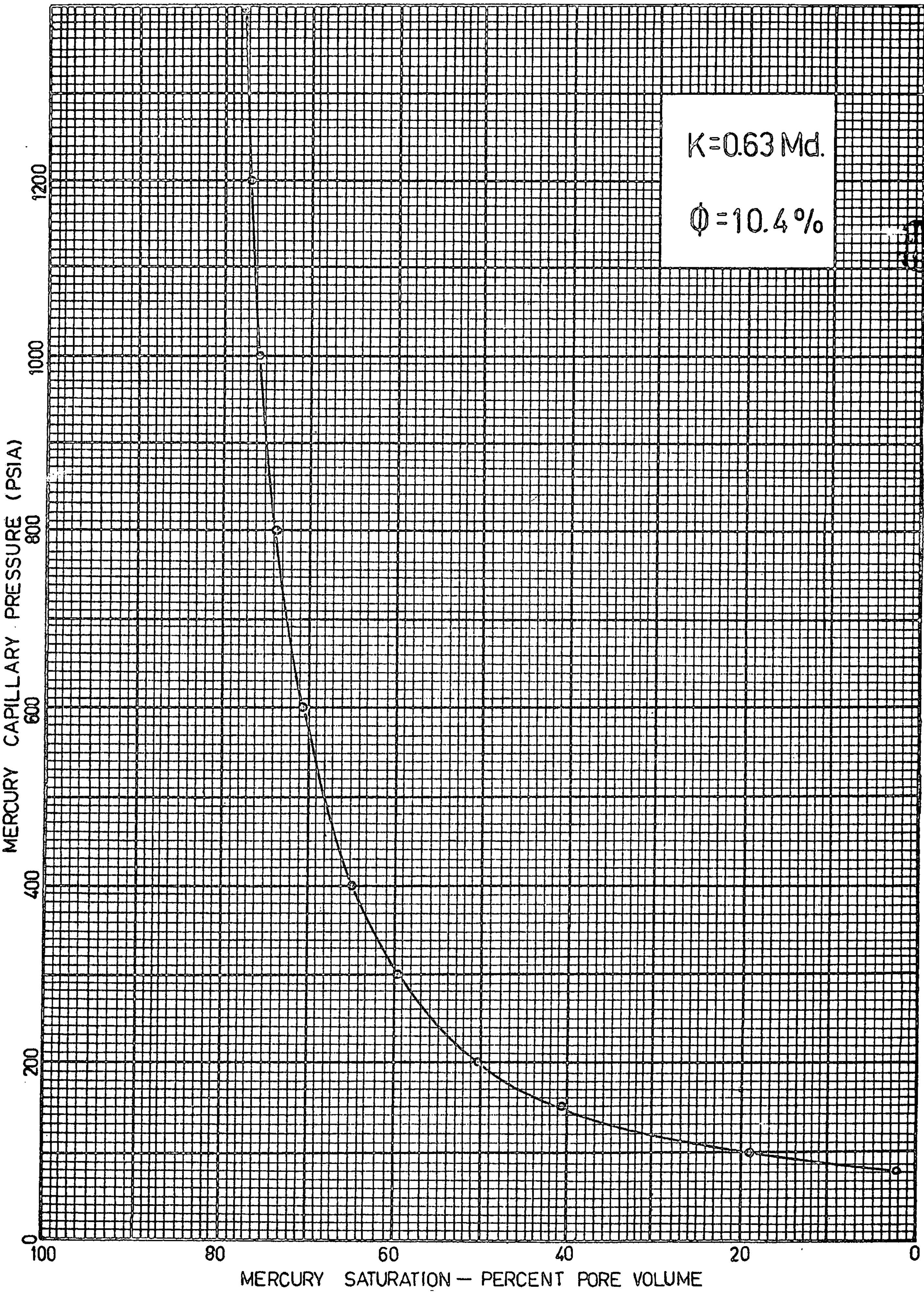

FIGURE 4

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH 4613

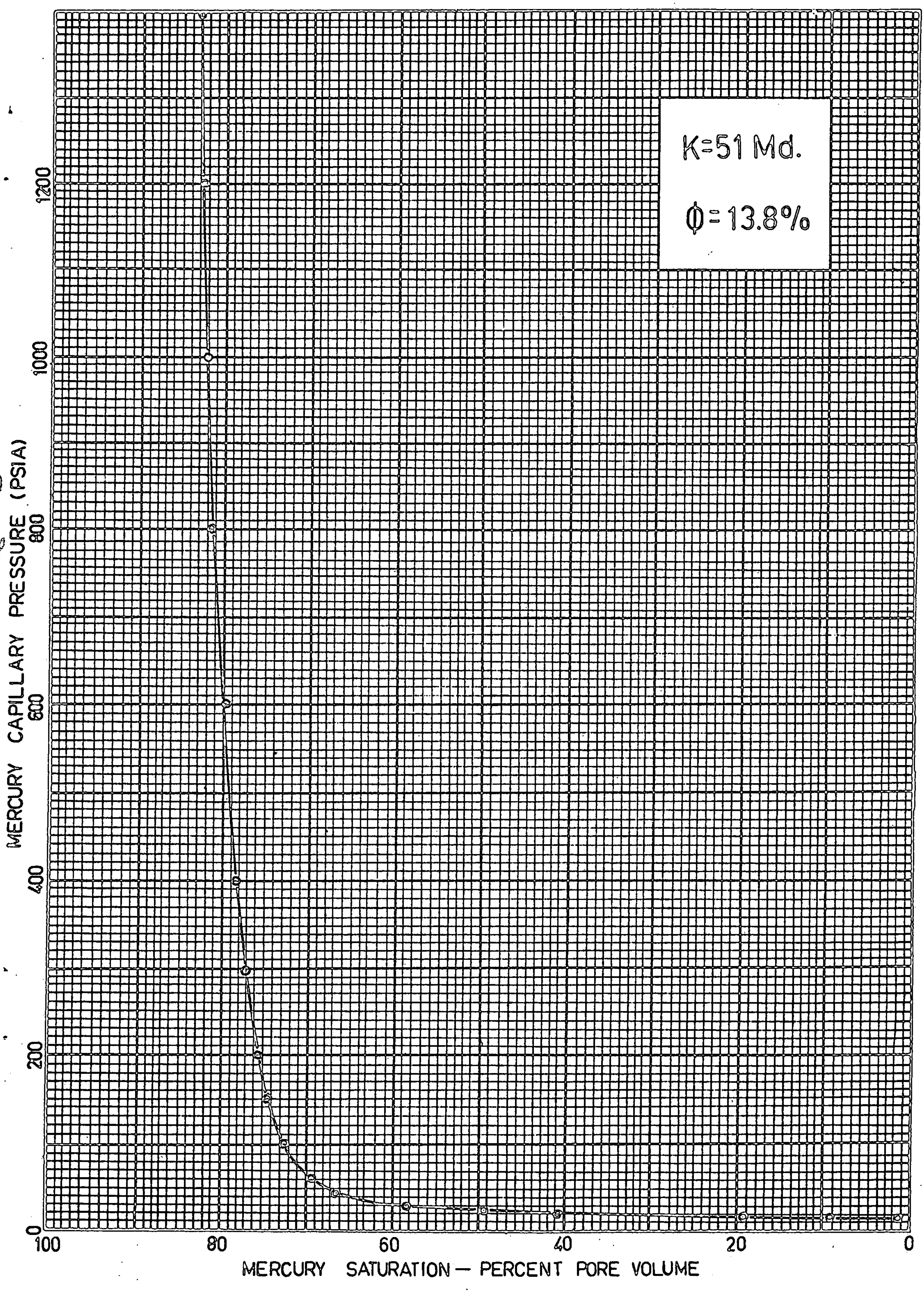

FIGURE 5

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH-4618

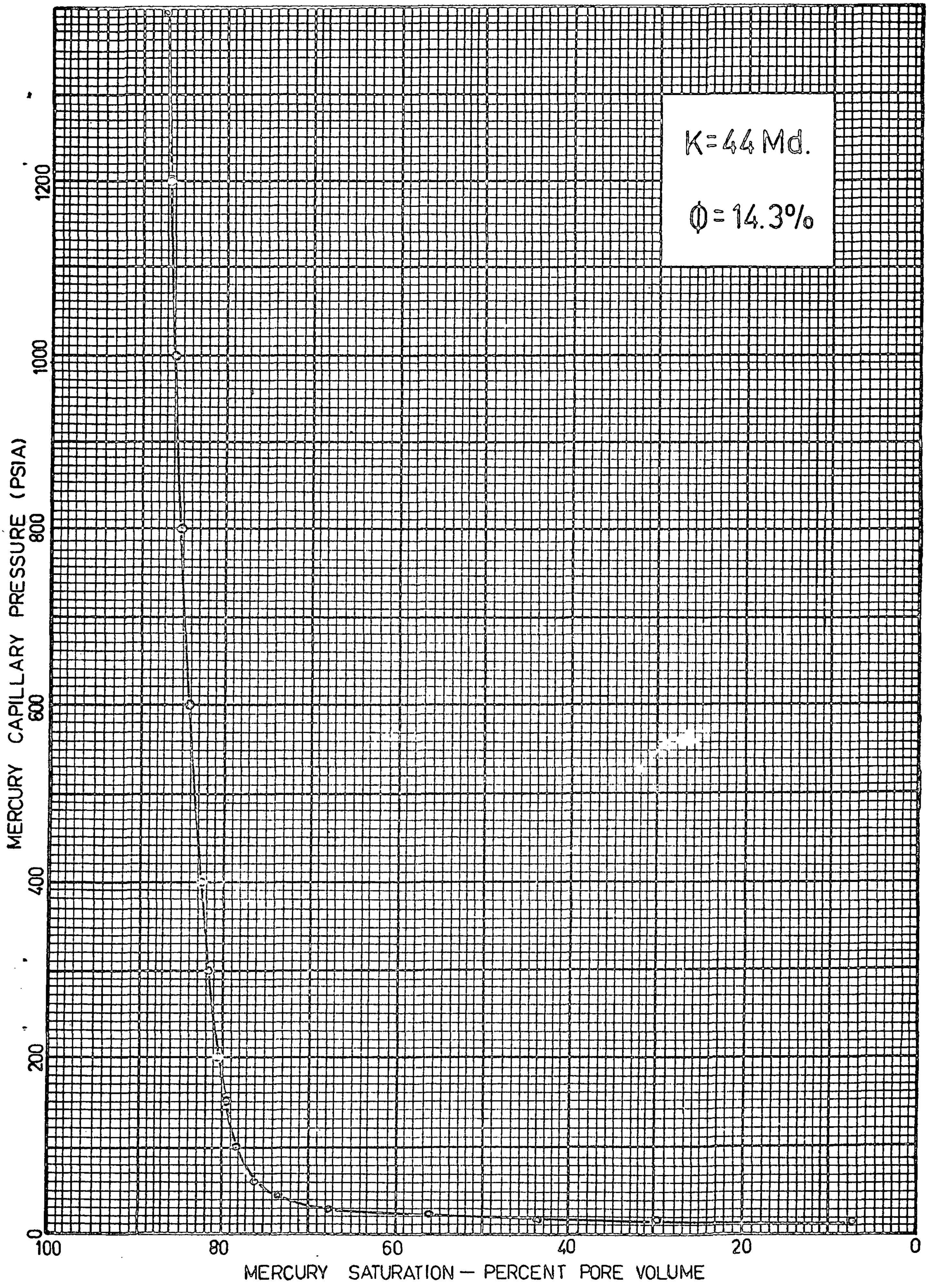

FIGURE 6

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH - 4625

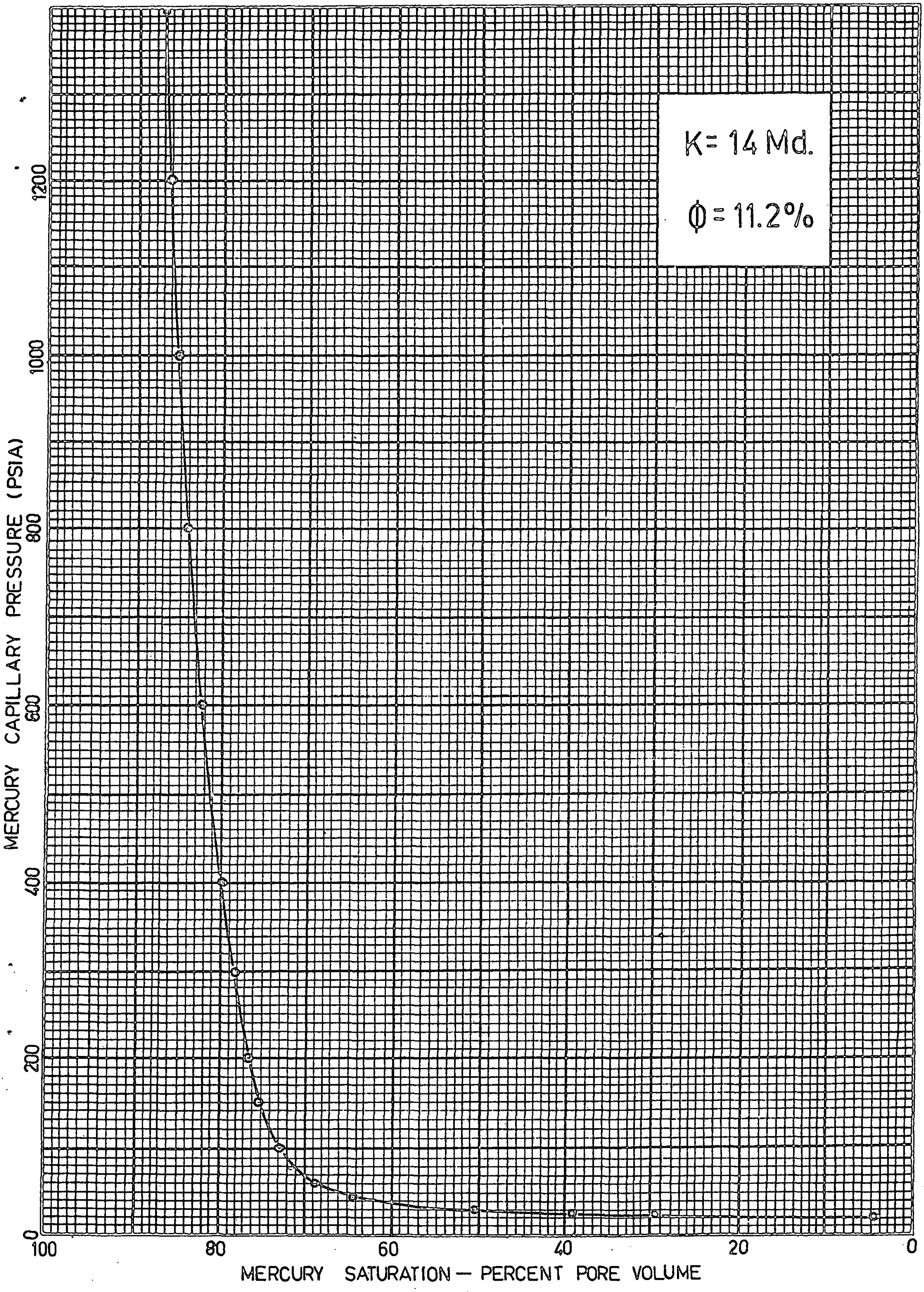

FIGURE 7

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH-4630

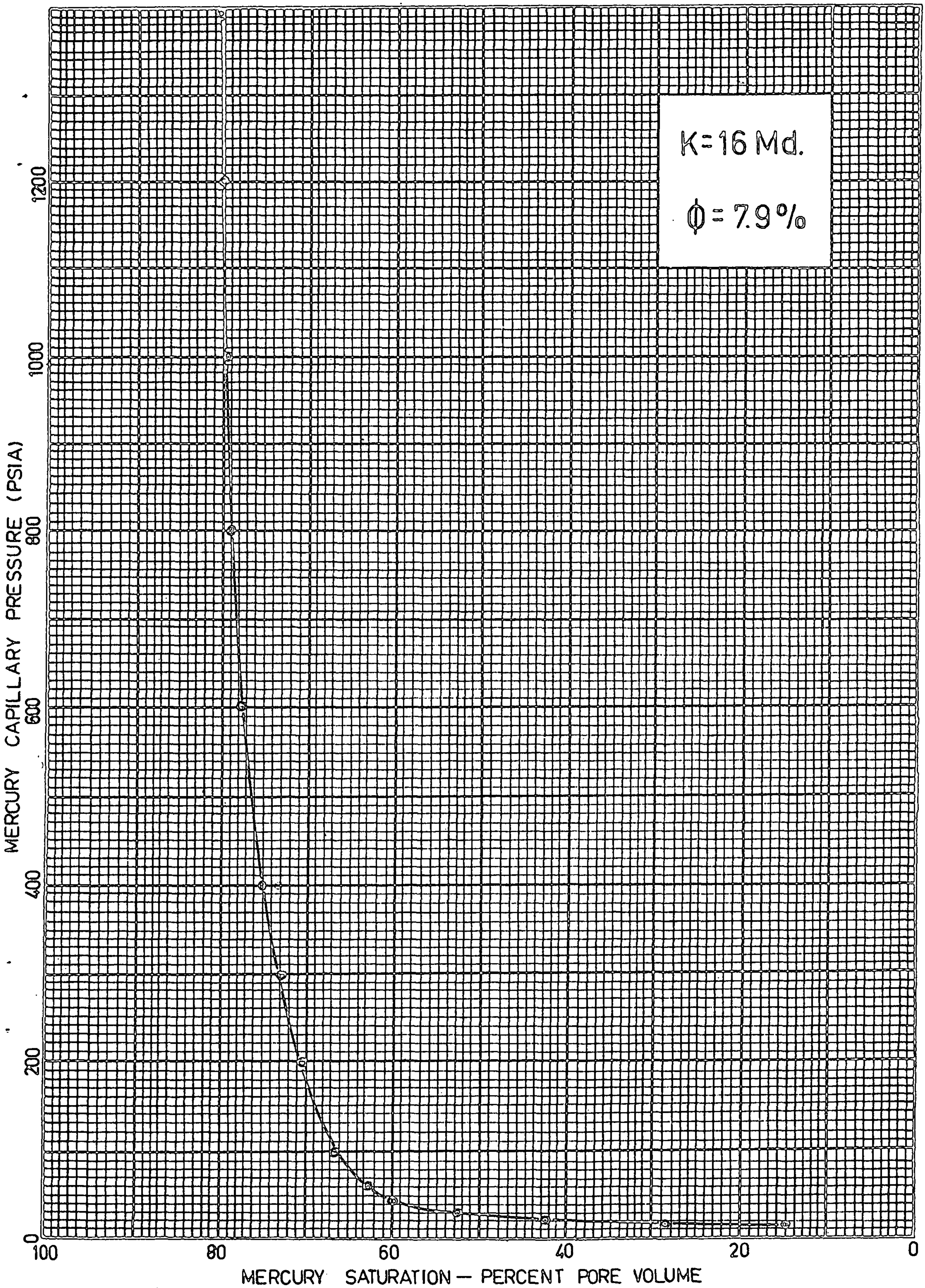

FIGURE 8

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH—4635

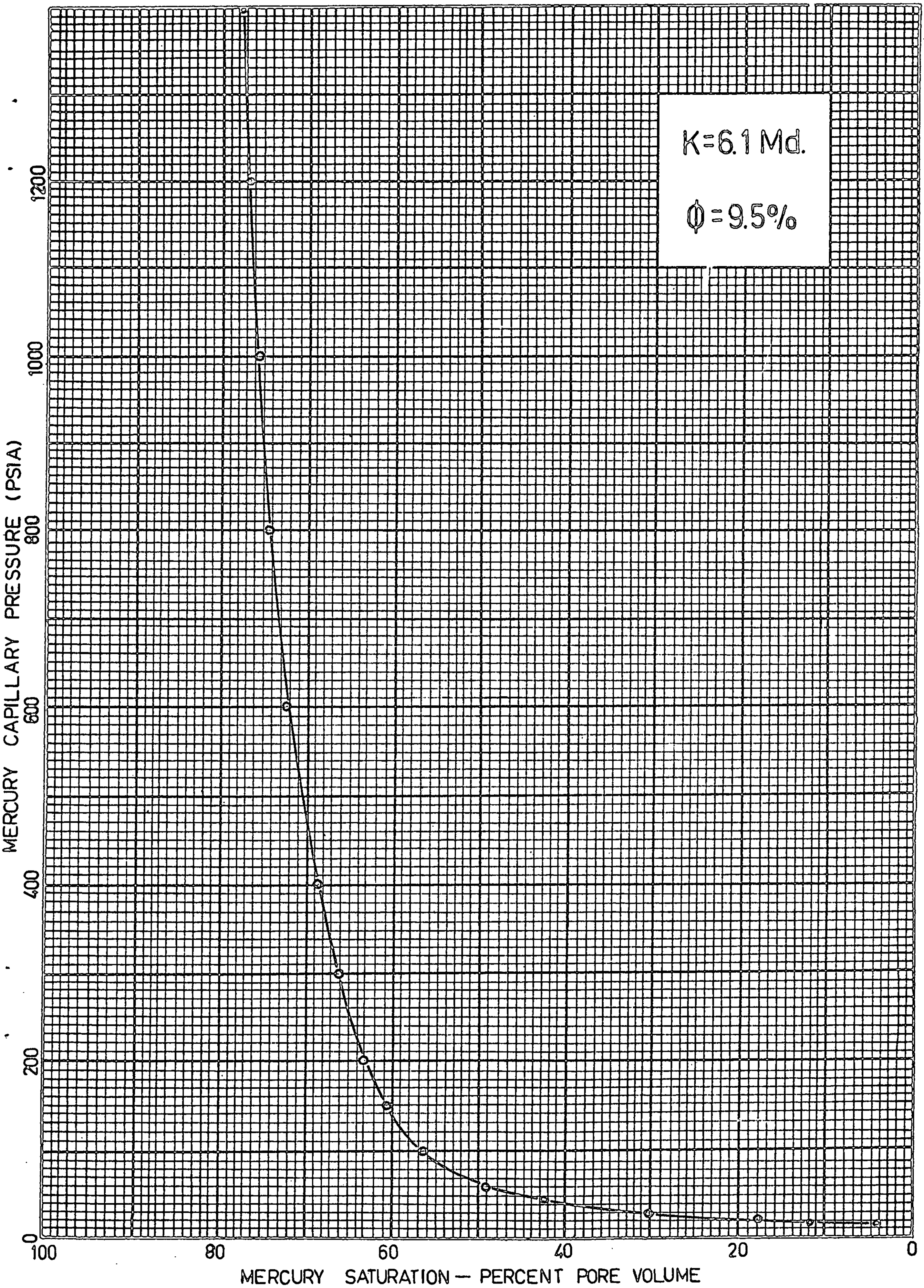

FIGURE 9

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4702

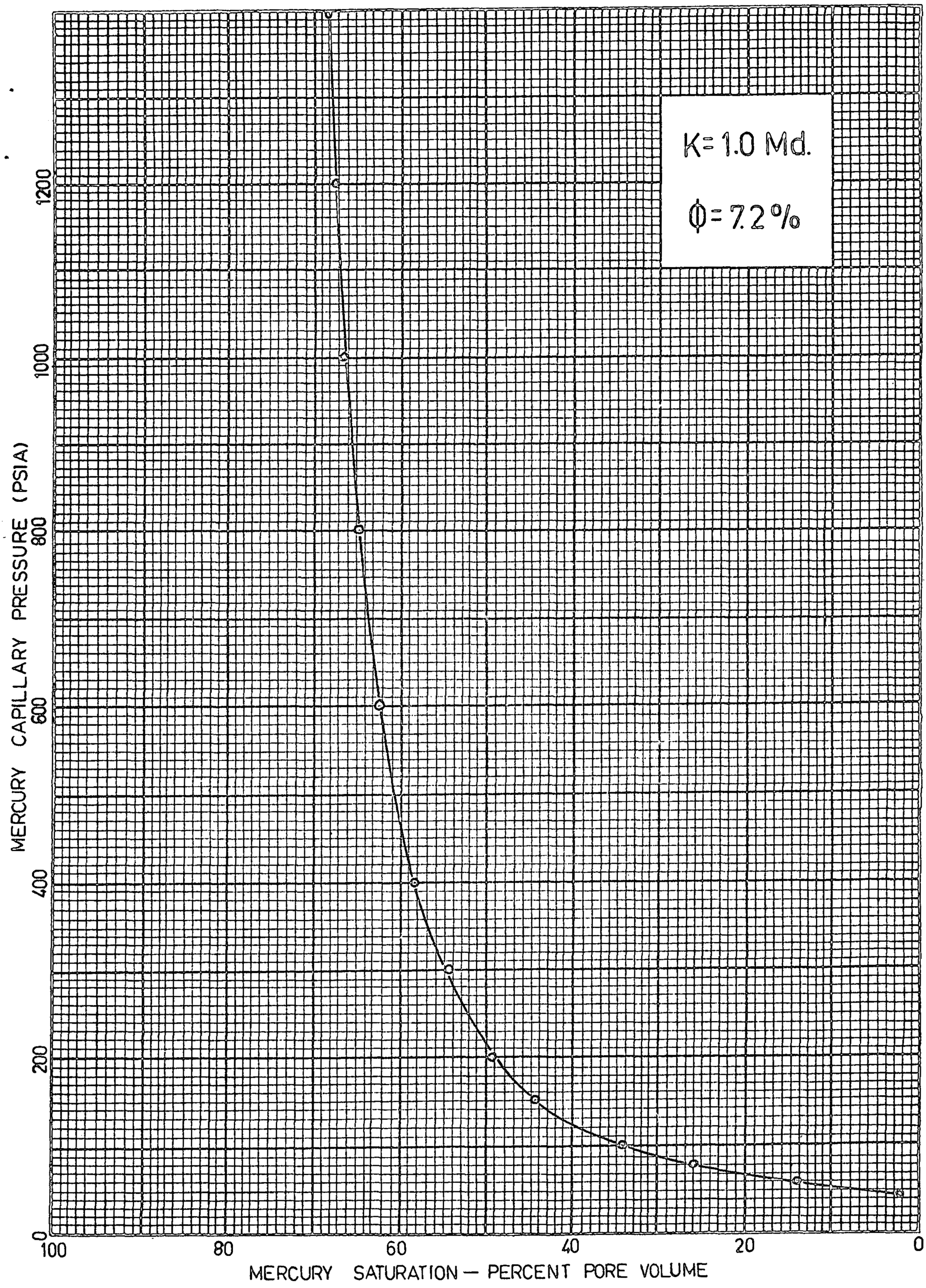

FIGURE 10

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4710

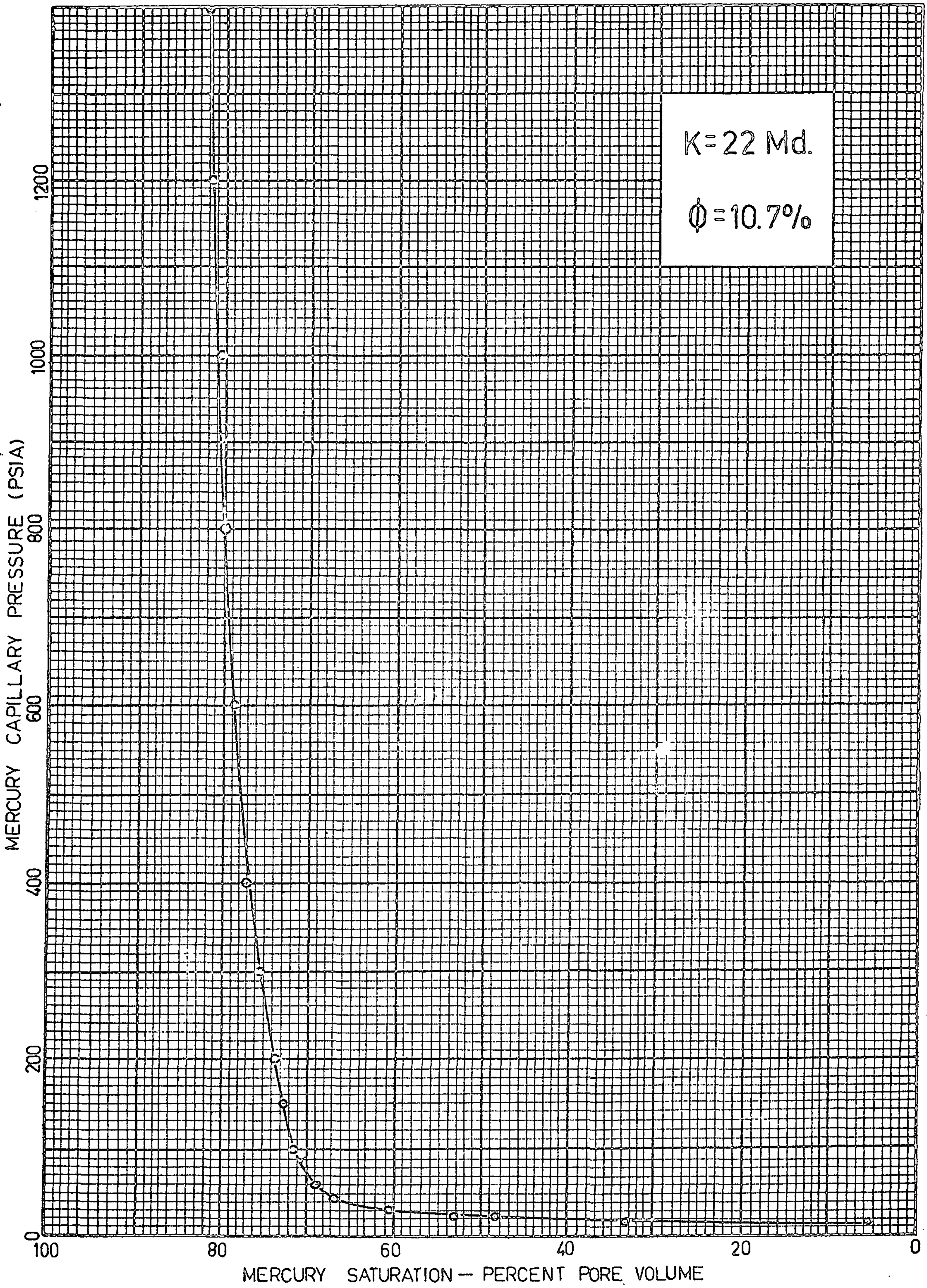

FIGURE 11

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4712

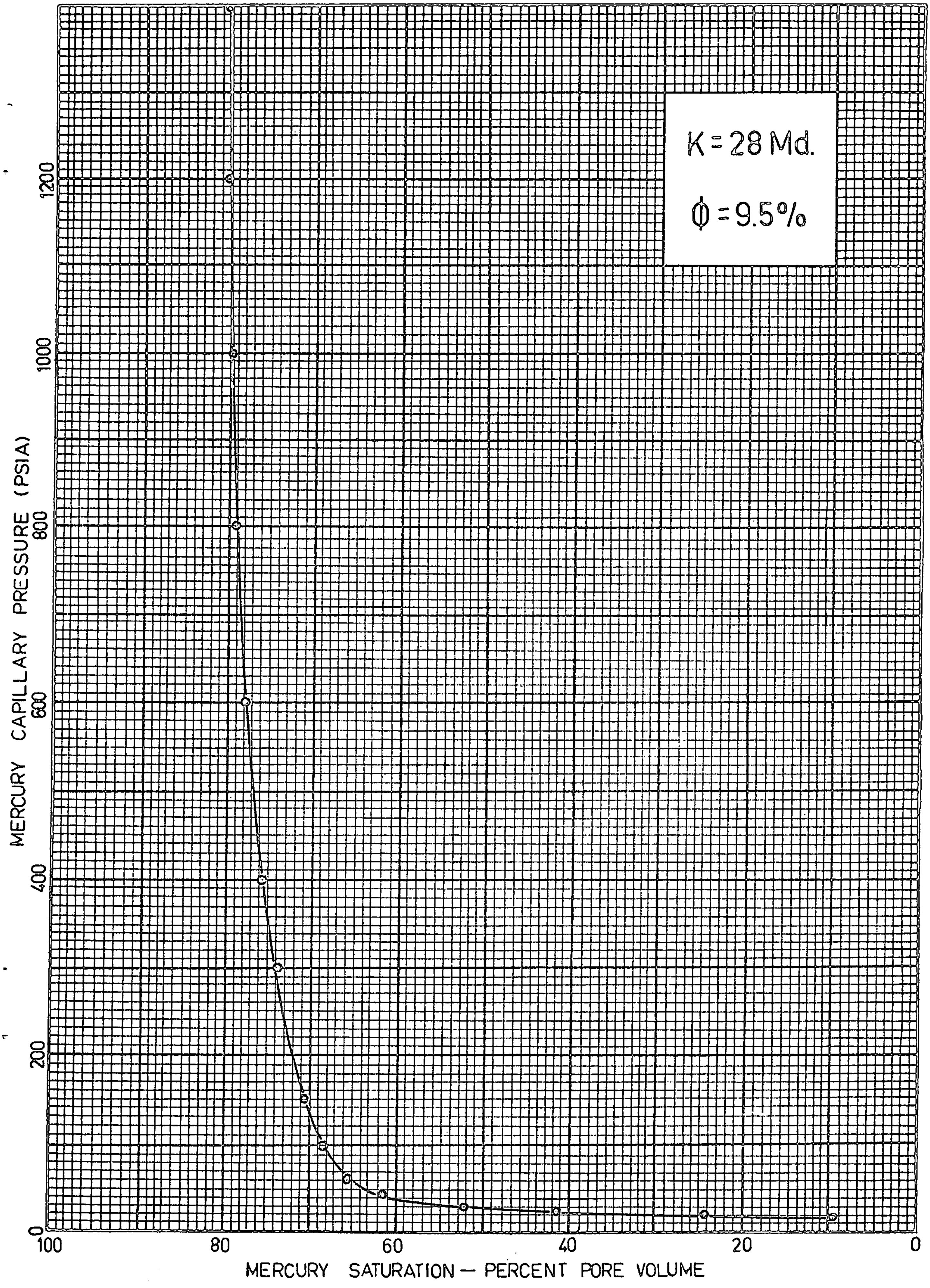

FIGURE 12

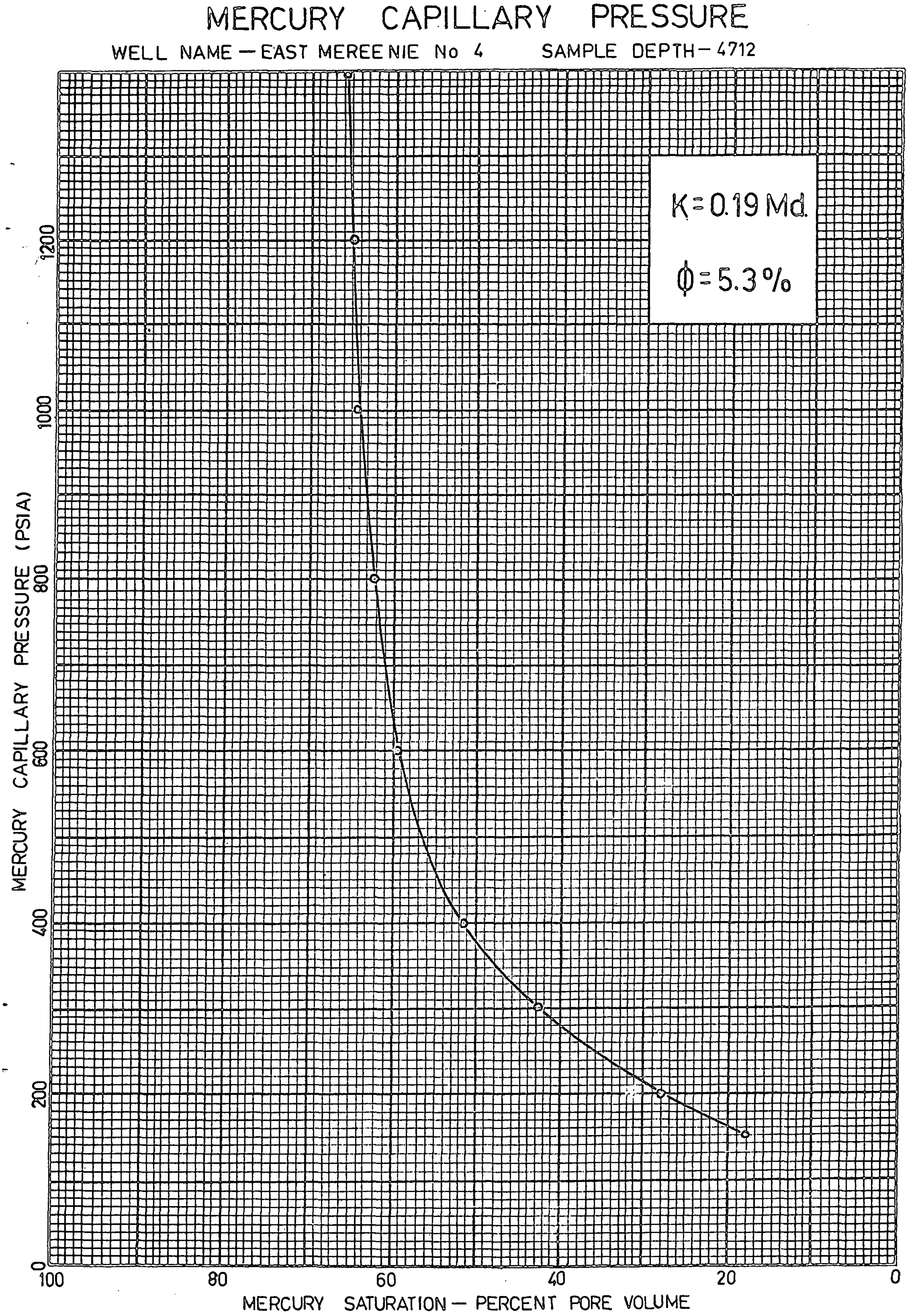
MERCURY CAPILLARY PRESSURE
WELL NAME — EAST MEREENIE No 4
SAMPLE DEPTH — 4712
K = 0.19 Md.
ϕ = 5.3 %
MERCURY CAPILLARY PRESSURE (PSIA)
0
200
400
600
800
1000
1200
100
80
60
40
20
0
MERCURY SATURATION — PERCENT PORE VOLUME

FIGURE 13

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4731

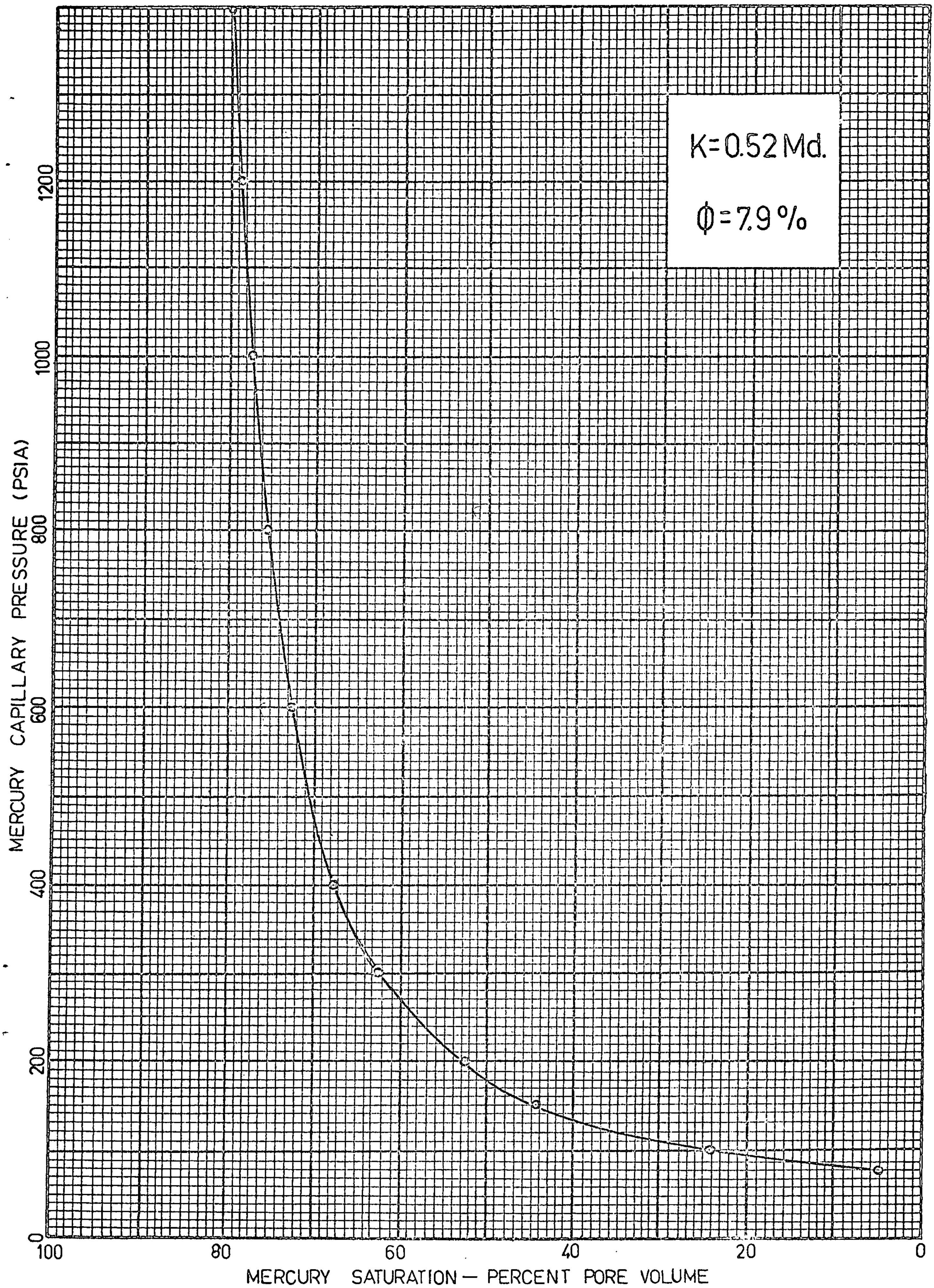

FIGURE 14

MERCURY CAPILLARY PRESSURE

WELL NAME —EAST MEREENIE No 4   SAMPLE DEPTH—4742

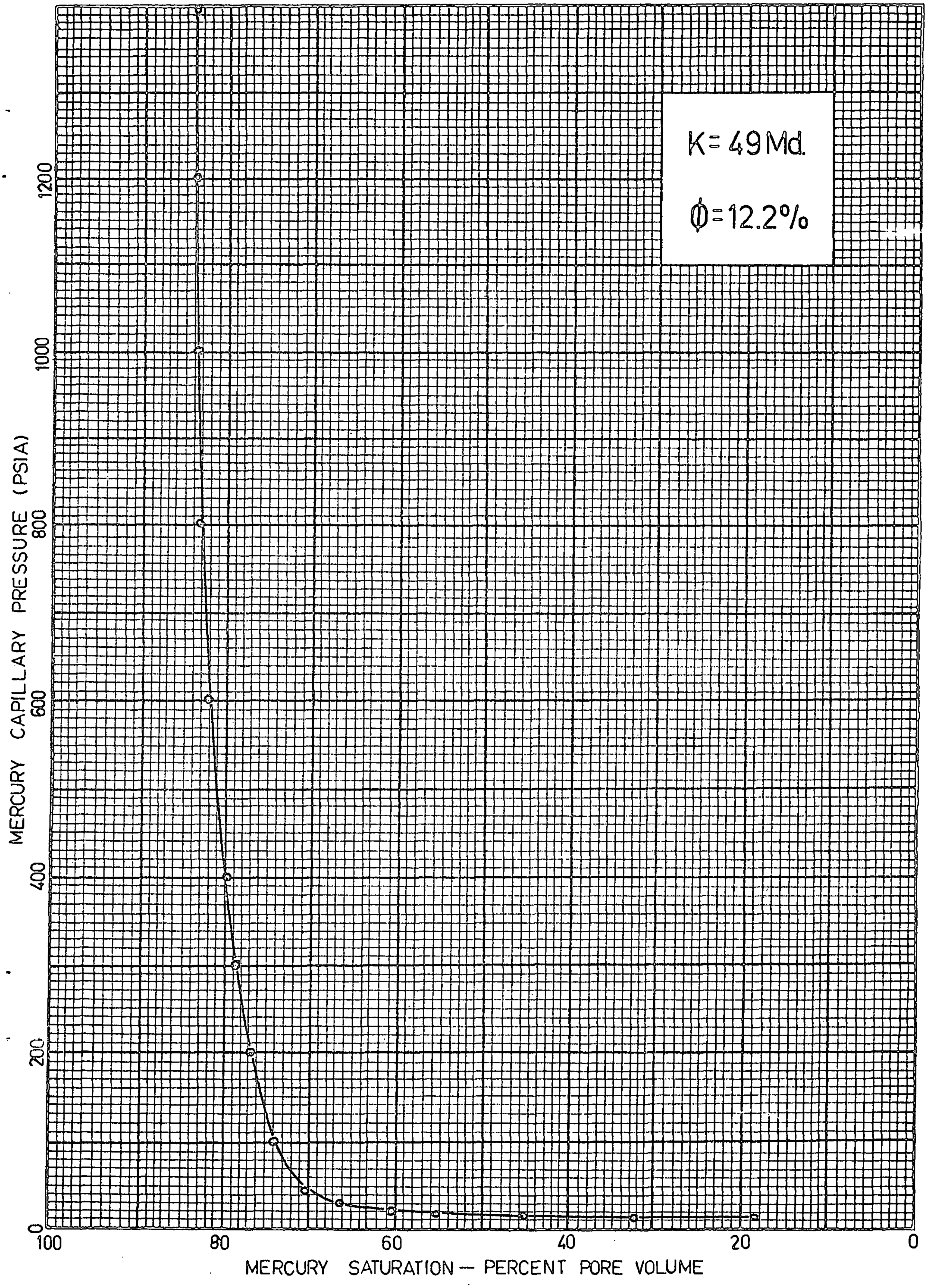

FIGURE 15

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4747

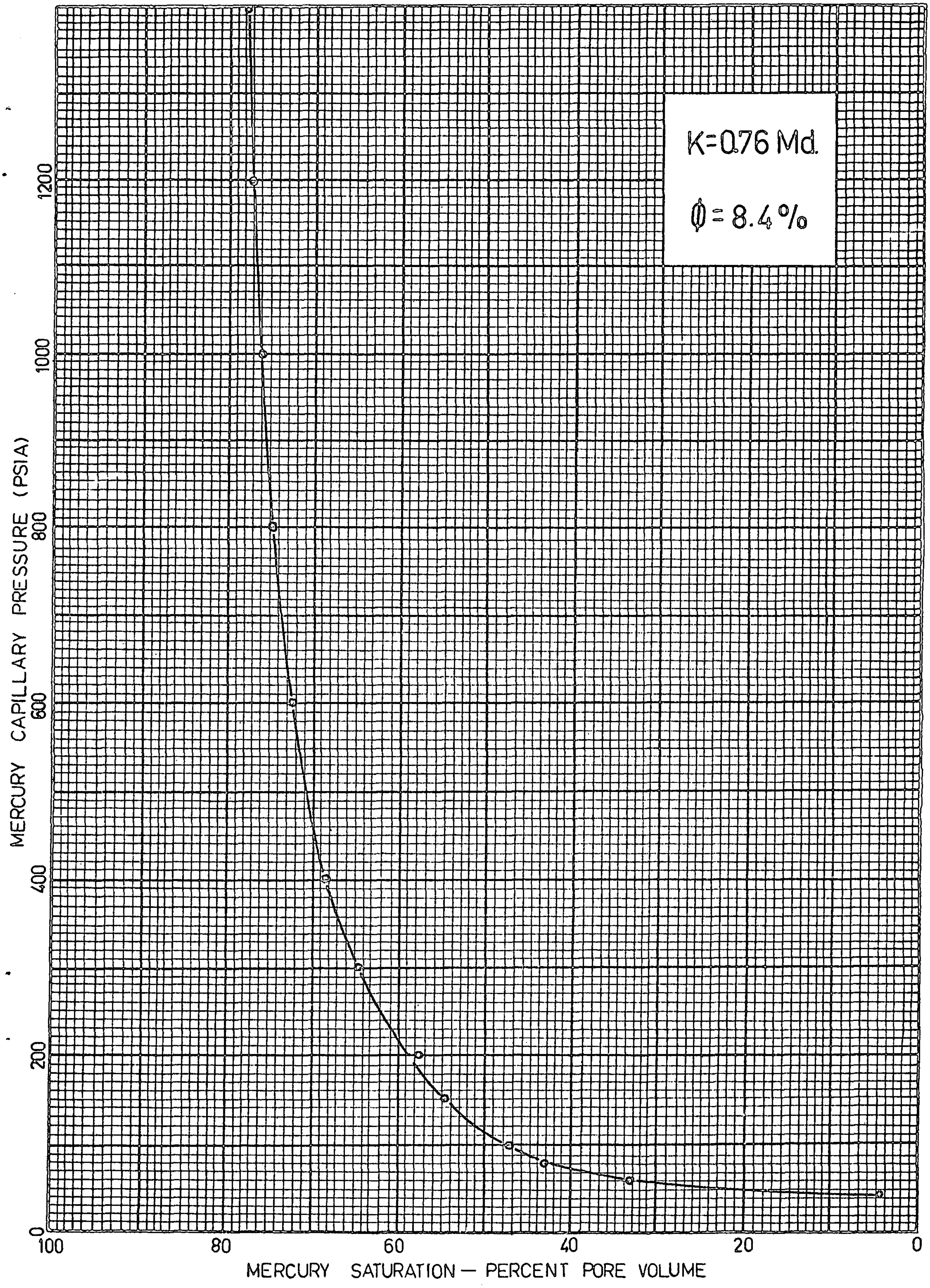

FIGURE 16

MERCURY CAPILLARY PRESSURE

WELL NAME — EAST MEREENIE No 4 SAMPLE DEPTH — 4752

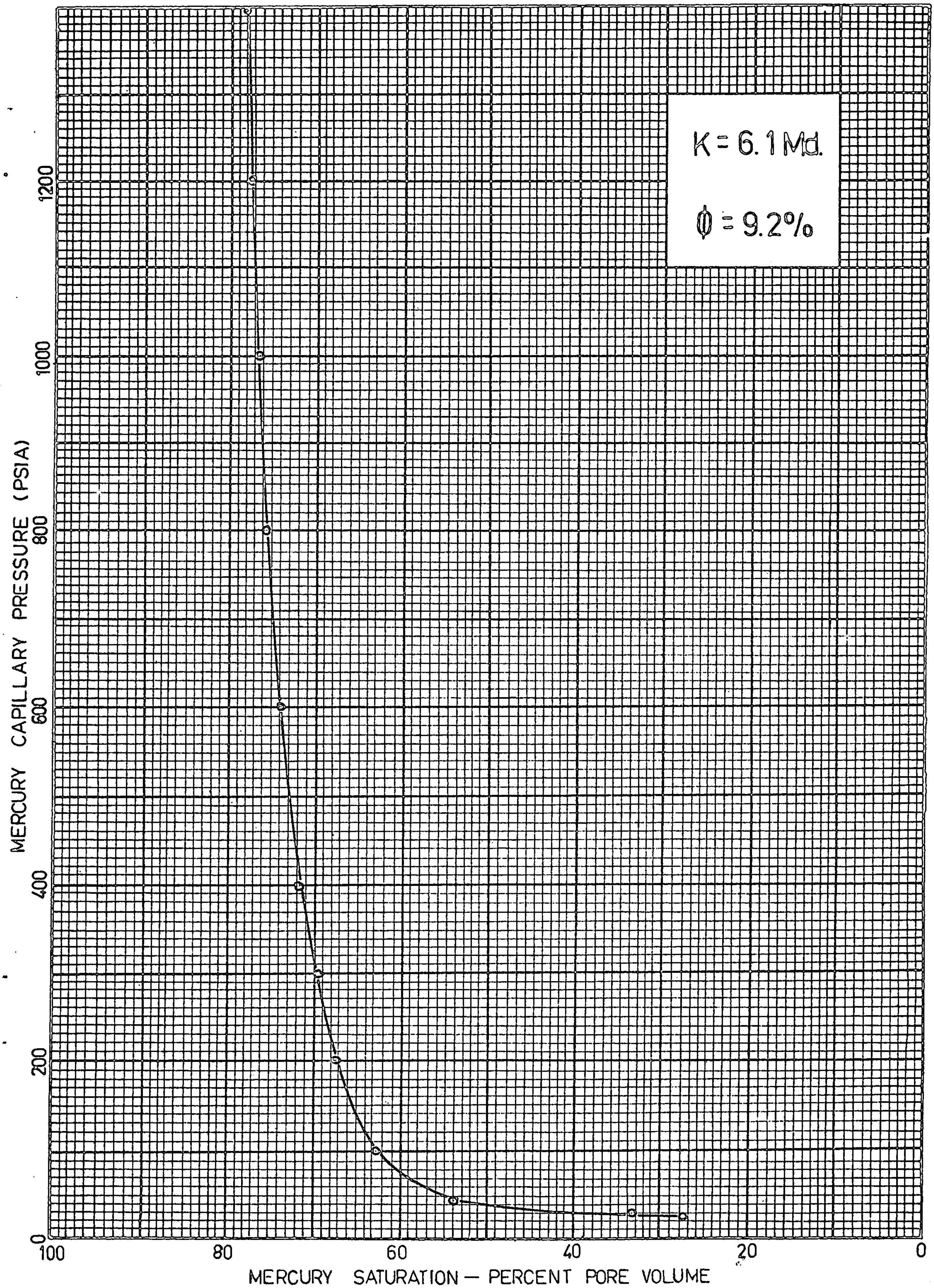

FIGURE 17

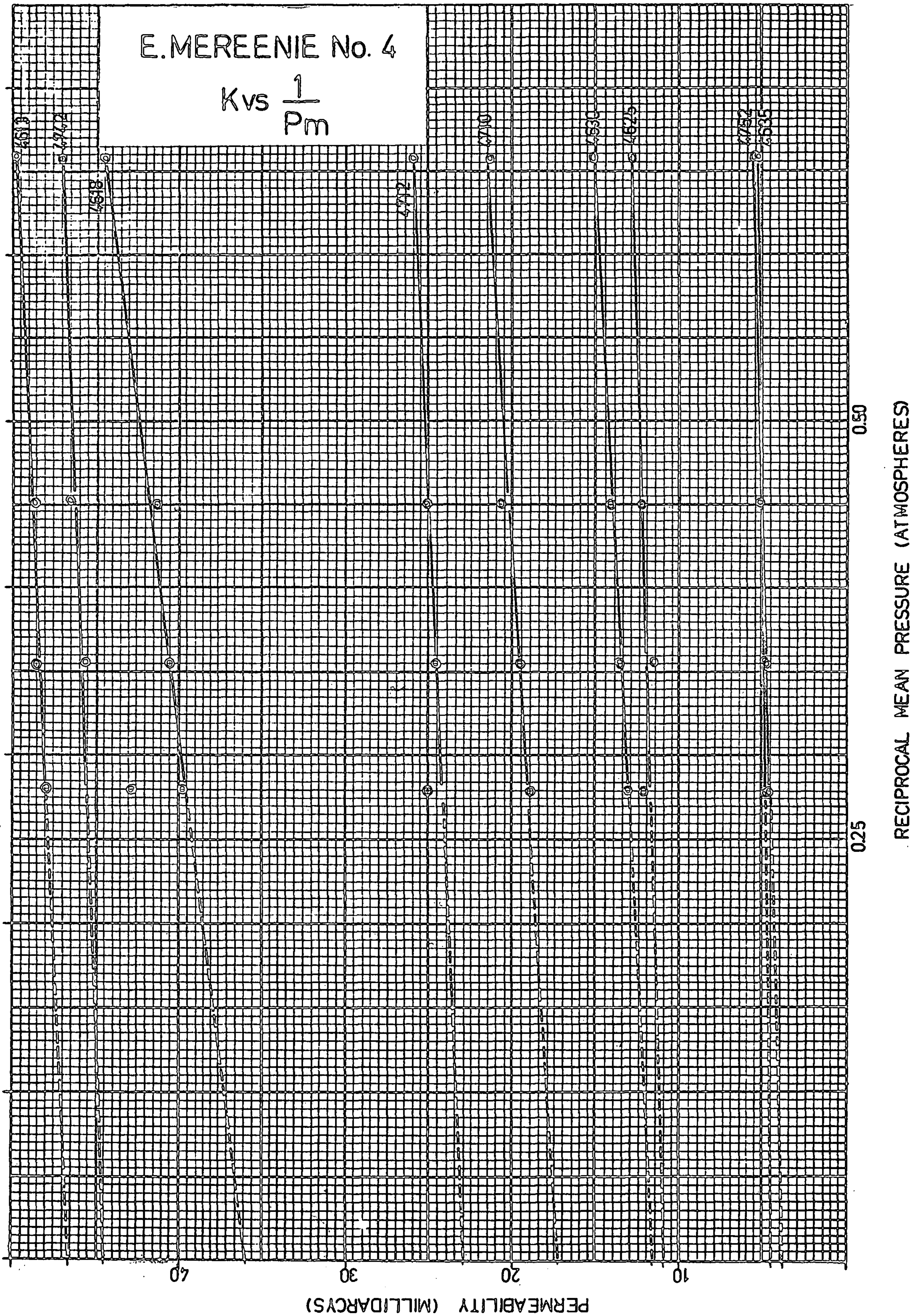
E. MEREENIE No. 4
K vs $\frac{1}{Pm}$
4613
4742
4618
4712
4710
4630
4625
4752
4635
0.50
0.25
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
40
30
20
10
PERMEABILITY (MILLIDARCYS)

FIGURE 18

CORE LABORATORIES TYPE RESISTIVITY APPARATUS

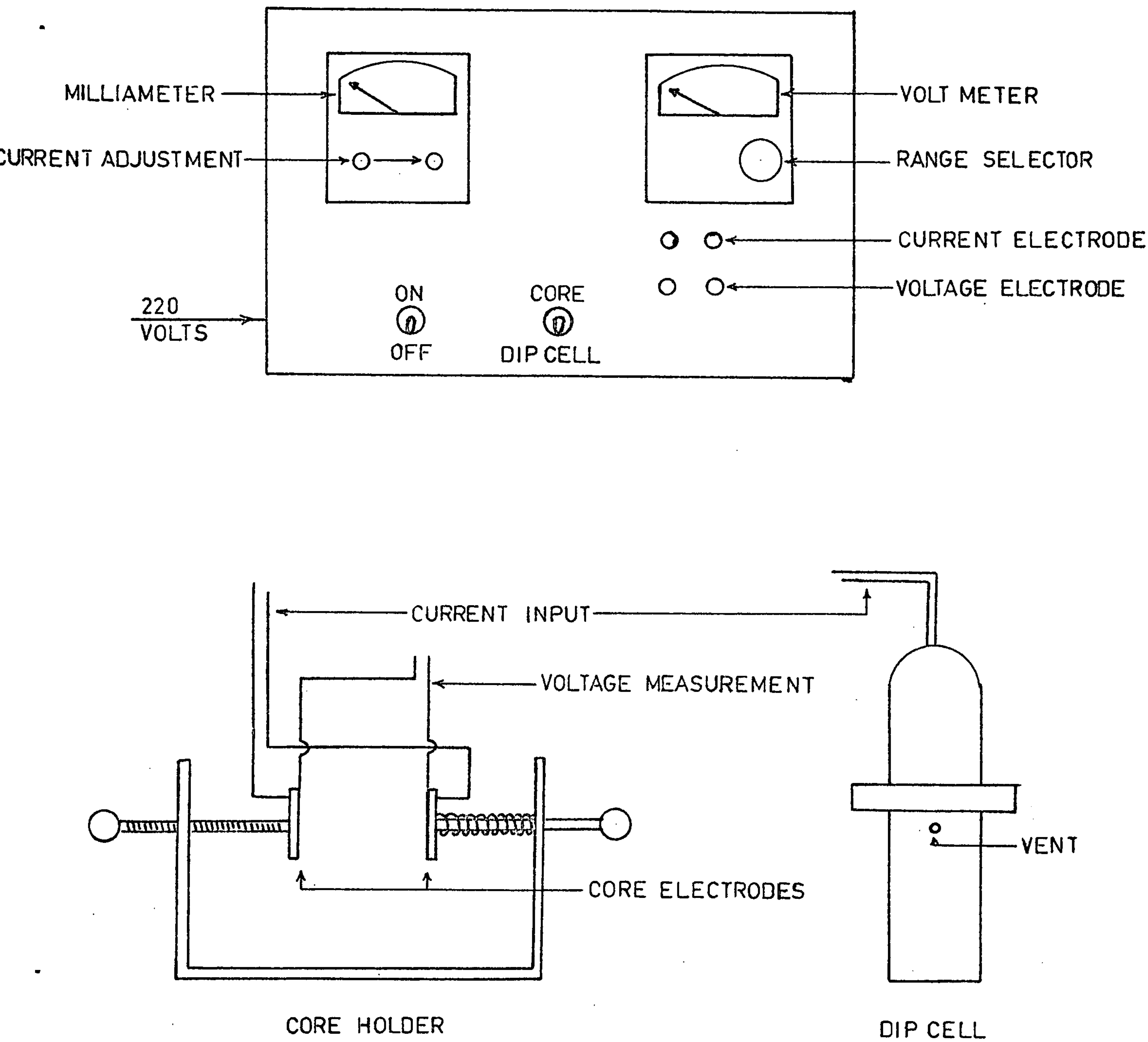

FIGURE 19

FORMATION FACTOR Vs POROSITY FRACTION

WELL NAME AND NUMBER- E.MEREENIE No. 4

DEPTH INTERVAL- 4196-4752

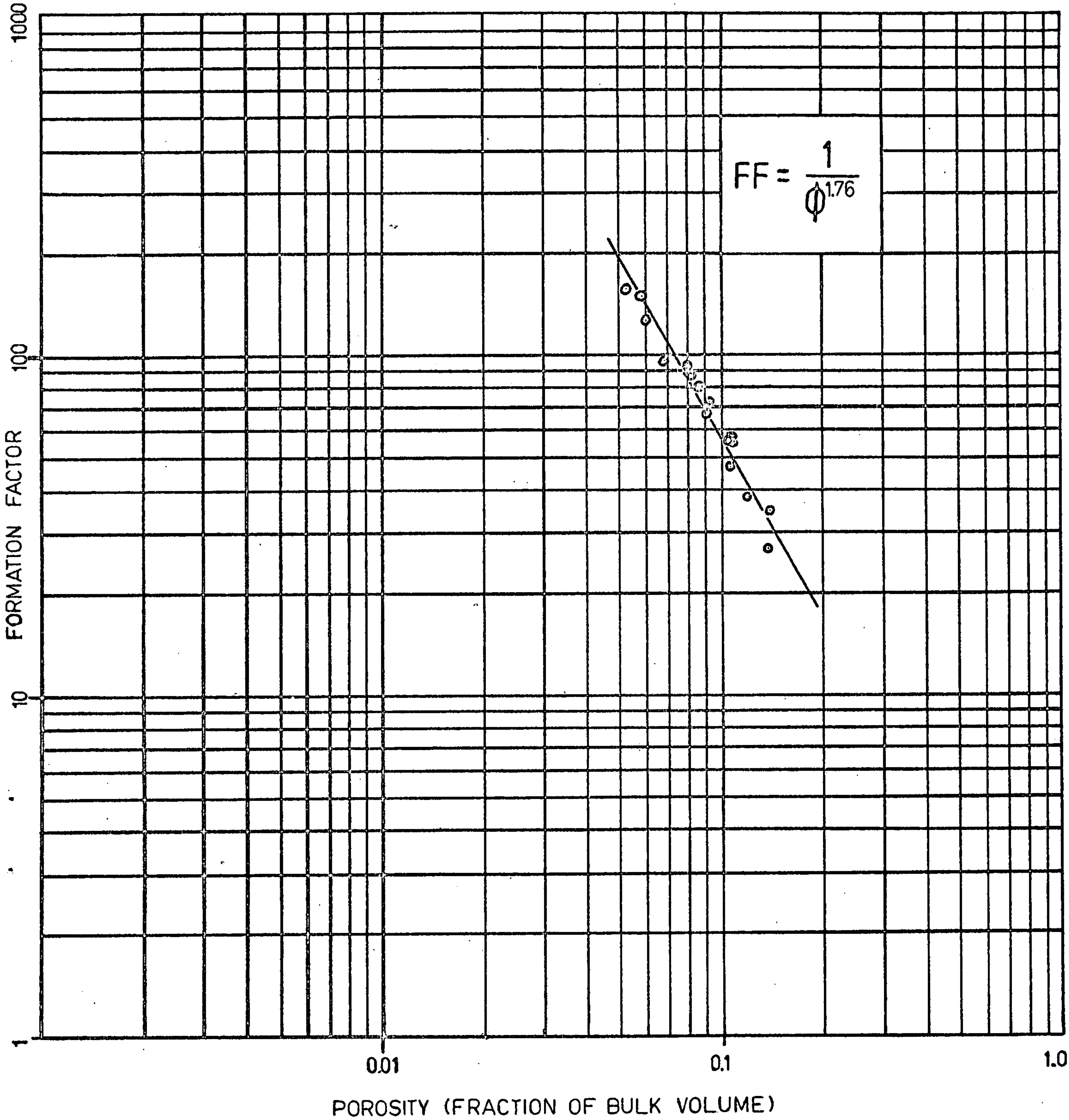

FIGURE 20

EAST MEREENIE NO. 4 ELECTRICAL LOG

SPONTANEOUS POTENTIAL (MILLIVOLTS)	DEPTH	RESISTIVITY OHMS-M^2/M	SAMPLE DEPTH (FEET)
-5+	2" = 100'	0 100