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MOONIE No 2
SPECIAL CORE ANALYSIS TESTS OF SAMPLES FROM THE LOWER JURASSIC PRECIPICE SANDSTONE

by

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5928/65

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INTRODUCTION

The Australian Oil and Gas Corporation obtained Authority to Prospect 57P in Queensland in 1958. Union Oil of California and the Kern County Land Company became farm-in partners with A.O.G. in 1959, and Union Oil Development Corporation acted as the operator in subsequent operations.

In November, 1961, these companies drilled Moonie No.1 as a test of an indicated domal closure in the Lower Jurassic Precipice sandstone. The well was successful and resulted in high gravity oil production from two intervals in the Precipice sandstone.

Moonie No.2 was sited half a mile south west of No.1. It was drilled in early 1962 further to evaluate the same Precipice sandstone section. Production was again established from two intervals (5651'-5675' and 5795'-5827') for a combined oil production of 2052 barrels per day.

Moonie No.2 was not subsidized by the Commonwealth Government under the Petroleum Search Subsidy Act, being excluded for payment when Moonie No.1 was declared an oil producer. However, no core was recovered from the producing intervals of Moonie No.1. Core samples for the following analysis were therefore obtained from the two producing intervals in Moonie No.2 through the courtesy of Union Oil and the Queensland Mines Department. The analyses cover porosity, permeability (gas and liquid), capillary pressure, wettability and electrical resistivity investigations.

PROCEDURE AND APPARATUS

Three separate sets of samples totalling 57 plugs were selected for testing. Nineteen $1\frac{1}{4}$-inch diameter plugs were selected for porosity, permeability (gas and liquid) and electrical resistivity determinations, nineteen $1\frac{1}{4}$-inch diameter plugs for oil/water imbibition tests, and nineteen $\frac{3}{4}$-inch diameter samples for mercury injection capillary pressure and pore size distribution measurements.

All the samples were diamond drilled parallel to the bedding from weathered whole core samples and trimmed with a diamond saw to an approximate length of $1\frac{1}{4}$ inches. They were extracted with toluene in a soxhlet-type apparatus for about 8 hours, then oven dried at 110°C for 24 hours. After cooling, the effective porosity and absolute permeability to dry nitrogen were determined.

The liquid flow tests were preceeded by "Klinkenberg" or equivalent liquid permeability tests, to evaluate flow capacity in each of the samples to a non-reactive liquid. Using nitrogen as the flowing phase, permeability was measured in each of the samples at several (four) different mean, but relatively constant differential pressures. These four permeability values for each sample were then plotted as a function of the reciprocal mean pressure, giving the non-reactive liquid permeability.

Separate liquid permeability tests were then performed on each of the samples to determine its compatability with various fluids. These were carried out using a light refined oil (SoltrolC), 3% NaCl brine, and fresh water as the flowing fluids respectively. Each test was preceded by extraction and drying of the samples; dry weight continuity checks were made on each of the samples between tests.

When the permeability tests had been done, the samples were again thoroughly extracted and dried, and then saturated with a 3% brine. Formation resistivity tests were conducted in a Core Laboratories type core resistivity apparatus (Figure 23). This equipment consists of a cell for measuring formation water resistivity and a core sample holder incorporating spring mounted electrodes for evaluating 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 were then correlated with sample porosity, enabling a cementation factor to be calculated from the slope of the curve of this correlation.

Mercury injection capillary pressure tests were then carried out in a Ruska type mercury injection appartus, following a method by Purcell (1). After extensive evacuation, each sample was subjected to increasing mercury pressure, and the volume of mercury injected at each pressure "step" was measured. The ultimate pressure used in each sample was 1400 psia.

The pressure/volume data obtained from tests on these samples were subsequently used for compilation of mercury capillary pressure curves, after corrections for mercury surface conformance and pump expansion had been made.

Pore size distribution values were calculated from the above 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).

Imbibition tests were conducted on the final nineteen $1\frac{1}{4}$-inch diameter samples to determine their fluid wetting characteristics. This was accomplished by saturating the samples with oil (Soltrol C) and immersing them in fresh water for a period of seven days. The amount of oil displaced by water from the samples over this period was noted.

DISCUSSION OF RESULTS

The results of the tests described above are listed as follows:

Table I shows the gas, liquid and "Klinkenberg" permeability results:

Table II the oil/water imbibition test results;

Table III the porosity and formation factor correlation:

Table IV the pore throat radius values calculated from the capillary pressure information.

The capillary pressure curves are shown in Figures 1-19; Figures 20-22 present the Klinkenberg test results; Figure 23 shows the core resistivity apparatus and Figure 24 presents the graphical correlation between porosity and formation factor of all the samples.

The liquid flow tests (Table I) with respect to oil, brine and fresh water resulted in values generally lower than the equivalent liquid (Klinkenberg) permeability (ELP). Permeability reductions were most pronounced using fresh water as the flowing medium, while flow tests using the Soltrol-C were most characteristic of the Klinkenberg values. However, no very severe reductions in permeability to any of the phases were noted. In addition, variations between the flow tests using brine and fresh water were not great, indicating minimal reductions in permeability due to swelling clays in the samples tested. The main reductions in flow capacity with respect to the aqueous phases were apparently caused by movement of mineral fines, creating some blockage of the pore channels and instability of flow rates during the tests.

The wetting characteristics of these samples from the oil/water imbibition tests indicated all material to be water-wet. Most of the plugs imbibed water readily within a short time of immersion in water. The maximum amount of oil displaced from the samples by the imbibing water was 49% of pore volume; this occurred in samples from the uppermost sandstone interval.

The reactions of two samples (5636' and 5686') were of particular interest. After immersion in fresh water for approximately 24 hours, both samples commenced to decompose; decomposition of the sample matrix was complete after the seven-day testing period. This was apparently caused by some water-sensitive clays in the rock in these particular zones. However, flow tests on other samples further to evaluate this phenomenon could not be carried out because of the impermeable nature of the core material in this zone.

The wide range of permeability values measured in the test samples was strongly reflected in the capillary pressure results. Very low and very high displacement (threshhold) pressures and residual water saturations were obtained throughout the intervals tested. Generally, samples with permeability greater than 10 millidarcys showed moderate to low displacement pressures and low water saturations. The balance of samples tested showed rather poor reservoir characteristics with very high indicated water saturations.

The plot of the formation factor and porosity shows a very good correlation between these two values. Point scattering of the plot was quite limited, although sample porosity covered a relatively wide range (9% to 22%). Two samples (5681' and 5785') were the main deviations from the plot; this could be a reflection of the inability to obtain 100% brine saturation conditions in these two plugs.

The cementation factor (m) derived from the slope of the line referred to above was found to be 1.76. Pirson's (2) classification system places samples with this cementation factor in a category of slightly to moderately well cemented, with porosities ranging up to 20%. This is quite consistent with the lithology of these samples and their measured porosity values (Table IV).

CONCLUSIONS

Special core analysis tests, comprising porosity, permeability (gas and liquid), capillary pressure, fluid imbibition and electrical resistivity measurements were conducted on core samples from the Moonie No.2 well, and have shown the following results:-

1. Flow tests using oil, brine and fresh water in the samples resulted in values lower than the Klinkenberg permeability, the fresh water phase giving the lowest result. However, permeability reductions were generally not severe, and appeared to be mainly caused by movement of mineral fines in the samples.

2. The results of the oil/water imbibition tests showed that all samples were water-wet. Water was rapidly imbibed into the samples shortly after immersion, and oil/water saturations generally became stabilized in the plugs after two days.

3. Mercury injection capillary pressure tests indicated low threshhold pressures and low residual water saturations in samples with permeability greater than 10 millidarcys. The remainder of the samples tested showed poor reservoir characteristics with high threshhold pressures and high indicated water saturations.

4. The correlation between formation factor and porosity in the samples was good; the cementation factor calculated from the resistivity tests was 1.76. This agrees closely with published values of rock with similar porosity and lithology.

REFERENCES

1. Purcell, W.R. "Capillary Pressures, Their Measurement using Mercury and the Calculation of Permeability Thereform". Petroleum Transactions, AIME, February, 1949.

2. Pirson, S.J. "Oil Reservoir Engineering"; 2nd Edition, page 107.

MOONIE NO.2

TABLE 1

SAMPLE DEPTH (FEET)	POROSITY (% BULK VOLUME)	DRY NITROGEN PERMEABILITY (Md.)	EQUIVALENT LIQUID PERMEABILITY (Md.)	PERMEABILITY TO SOLTROL		PERMEABILITY TO 3% BRINE		PERMEABILITY TO FRESH WATER	
				Md.	% E.L.P.	Md.	% E.L.P.	Md.	% E.L.P.
5636	9.5	<0.1	-	-	-	-	-	-	-
5641	13.0	1.5	0.5	0.76	150	0.27	54	0.35	70
5646	19.0	29	24	22	92	13	54	11	46
5651	14.6	13	8.0	9.2	113	4.7	59	3.7	46
5656	21.6	654	550	527	96	355	65	294	52
5668	19.7	1052	950	903	97	845	91	546	59
5671	20.5	472	362	300	83	207	57	151	42
5681	10.5	< 0.1	-	-	-	-	-	-	-
5686	11.3	0.14	-	-	-	-	-	-	-
5785	8.7	<0.1	-	-	-	-	-	-	-
5823	17.6	118	82	85	104	47	57	59	72
5831	17.6	76	60	51	85	45	75	43	72
5834	13.8	4.5	3.0	2.8	93	1.7	57	1.6	53
5847	15.7	382*	-	-	-	-	-	-	-
5855	11.2	0.12	-	-	-	-	-	-	-
5863	20.3	320	250	255	102	151	61	113	45
5867	17.9	735	620	473	76	484	78	437	70
5877	22.5	2755	2600	2630	101	2630	101	1820	70
5879	19.4	6176	5850	5840	99	5150	88	4360	75

* Mounted in Wax

MOONIE NO.2

TABLE 2

CORE NUMBER	SAMPLE DEPTH (FEET)	POROSITY (% BULK VOLUME)	DRY NITROGEN PERMEABILITY (Md.)	SATURATING MEDIUM	VOLUME OF WATER IMBIBED (% PORE VOLUME)			
					AFTER 1 DAY	AFTER 2 DAYS	AFTER 3 DAYS	AFTER 7 DAYS
2	5636	9.5	<0.1	Soltrol	5.9	Sample Disintegrated		
2	5641	13.0	1.5	"	30	30	30	30
2	5646	19.0	29	"	48	48	49	49
3	5651	14.6	13	"	41	41	41	41
3	5656	21.6	654	"	28	33	33	35
3	5668	19.7	1052	"	29	33	33	34
3	5671	20.5	472	"	31	31	32	33
4	5681	10.5	<0.1	"	15	20	20	20
4	5686	11.3	0.14	"	7.3	14.0	Sample Disintegrated	
5	5785	8.7	<0.1	"	11	11	11	14
6	5823	17.6	118	"	4.3	6.4	8.7	12
6	5831	17.6	76	"	30	32	34	34
6	5834	13.8	4.5	"	26	33	33	33
6	5847	15.7	382	"	5.5	14	16	19
7	5855	11.2	0.12	"	13	19	19	19
8	5863	20.3	320	"	30	30	33	35
8	5867	17.9	735	"	13	17	24	26
9	5877	22.5	2755	"	5	9	12	12
9	5879	19.4	6176	"	10	13	15	17

TABLE 3

	MERCURY SATURATION (% PORE VOLUME)									SAMPLE DEPTH (FEET)
	0-10	10-20	20-30	30-40	40-50	50-60	60-70	70-80	80-90	
PORE ENTRY RADIUS (MICRONS)		0.95	0.65	0.44	0.28	0.17				5641
		4.4	2.4	2.0	1.2	0.70	0.34	0.15		5646
		1.6	1.2	0.77	0.48	0.26	0.11			5651
		21	16	9.7	4.8	2.2	0.95	0.32		5656
		39	22	12	4.6	2.2	0.92	0.27		5668
		16	9.3	4.1	2.0	0.89	0.32			5671
		7.1	4.1	2.4	1.4	0.68	0.28			5823
		7.1	4.3	2.5	1.4	0.71	0.31			5831
			1.8	1.1	0.65	0.36	0.17			5834
		22	13	6.7	3.5	1.6	0.66	0.21		5847
		0.23	0.15							5855
		13	7.5	4.6	2.4	1.2	0.57	0.22		5863
		19	13	8.2	3.6	1.2	0.36			5867
		44	43	30	22	12	3.4	0.39		5877
		37	32	28	17	7.2	1.8	0.30		5879

	MERCURY SATURATION (% PORE VOLUME)									SAMPLE DEPTH (FEET)
	0-2	2-4	4-6	6-8	8-10	10-12	12-14	14-16	16-18	
PORE ENTRY RADIUS (MICRONS)		0.15	0.13	0.10	0.09					5636
		0.12	0.09							5681
		0.47	0.37	0.27	0.18	0.13				5686
						0.13	0.12	0.10	0.08	5785

TABLE IV

SAMPLE DEPTH (FEET)	PERMEABILITY TO DRY NITROGEN (Md.)	POROSITY % BULK VOLUME	FORMATION FACTOR	LITHOLOGY
5636	<0.1	9.5	65	Sandstone, very fine grained, well consolidated, clayey
5641	1.5	13.0	37	" , fine to medium grained, carbonaceous shaley Laminae
5646	29	19.0	20	Sandstone, fine grained, sub angular grained
5651	13	14.6	30	" , medium to coarse grained, silty
5656	654	21.6	14	" , fine to medium grained subangular grains
5668	1052	19.7	18	" , medium to coarse grained, angular to sub angular.
5678	472	20.5	17	Sandstone, medium to coarse grained to pebbly
5681	<0.1	10.5	87	" , very fine grained, well consolidated
5686	0.14	11.3	53	" , as above, clayey matrix
5785	<0.1	8.7	100	" , as above
5823	118	17.6	23	" , fine to coarse grained to pebbly
5831	76	17.6	19	" , as above
5834	4.5	13.8	32	" , very fine to fine grained, well consolidated
5847	382	15.7	N.D.*	Conglomerate, quartzose cobbles, pebbles, fine grained matrix
5855	0.12	11.2	50	Sandstone, very fine grained, micaceous
5863	320	20.3	19	" , coarse to very coarse grained, subangular
5867	735	17.9	22	" , fine to coarse grained, angular-subangular
5877	2755	22.5	15	" , as above, sub angular, sub rounded
5879	6176	19.4	22	" , medium grained to pebbly sub angular to sub rounded.

*N.D. - Not Determined.

FIGURE 1

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH—5636

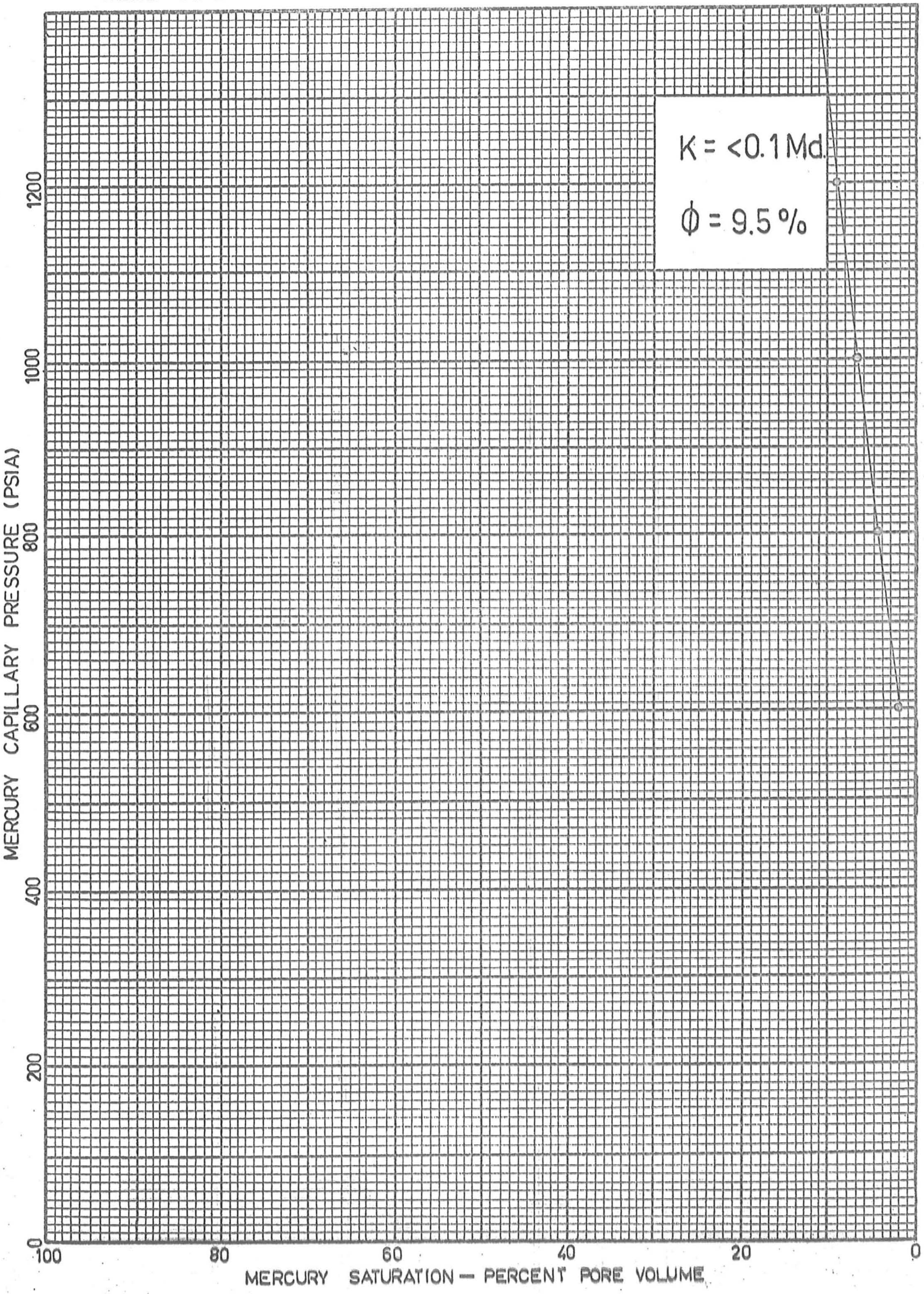


FIGURE 2

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2   SAMPLE DEPTH - 5641

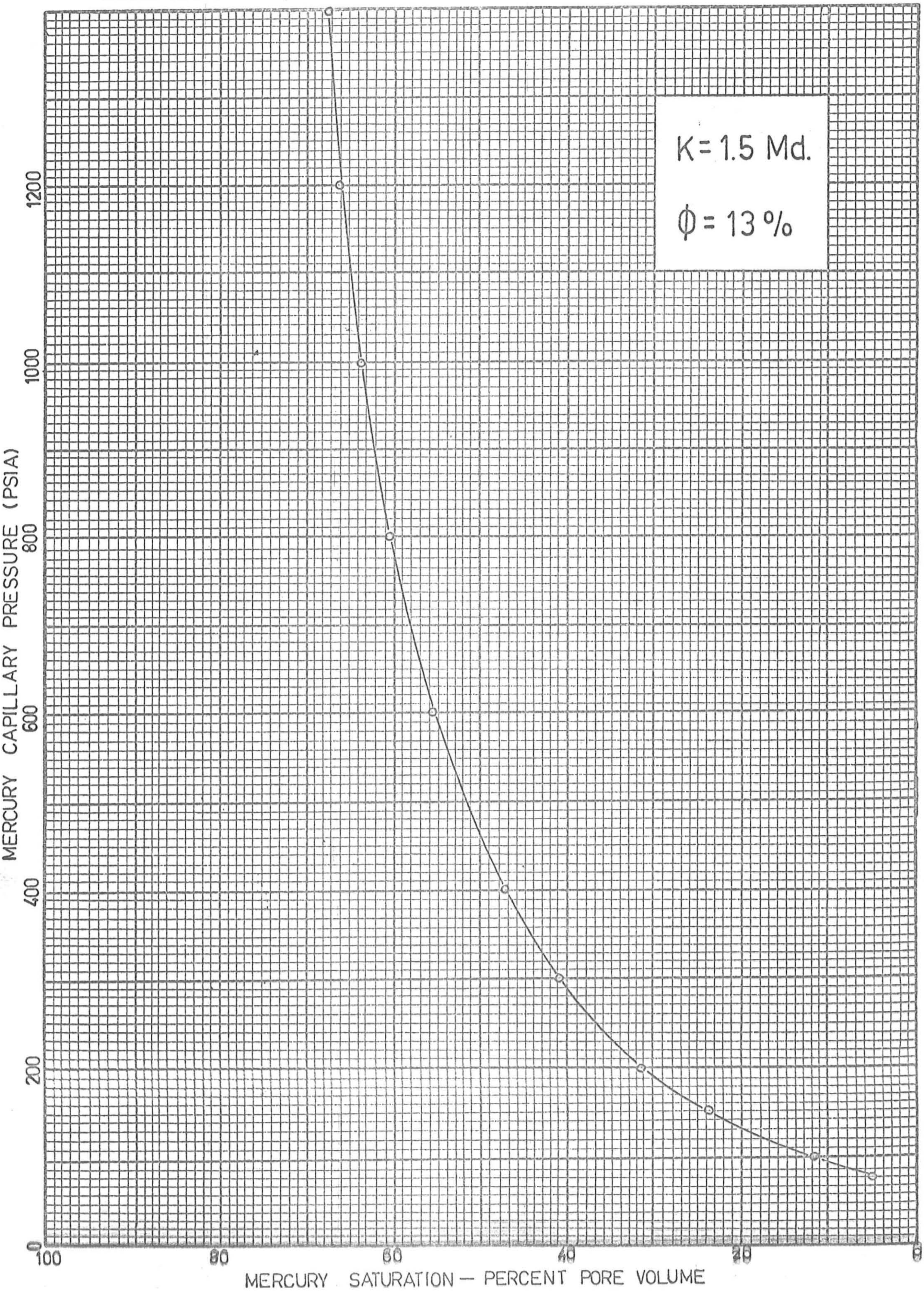


FIGURE 3

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH - 5646

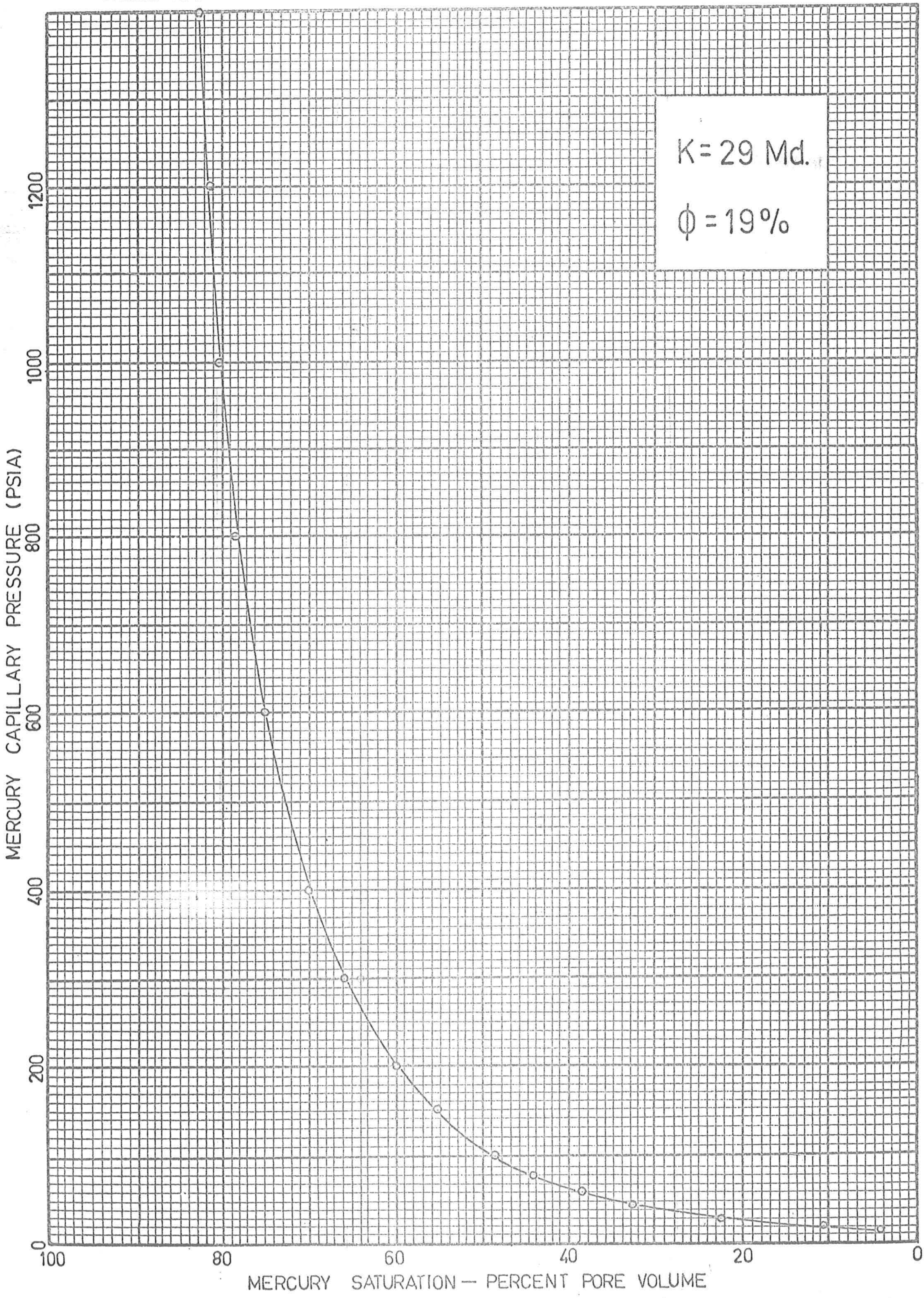


FIGURE 4

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH—5651

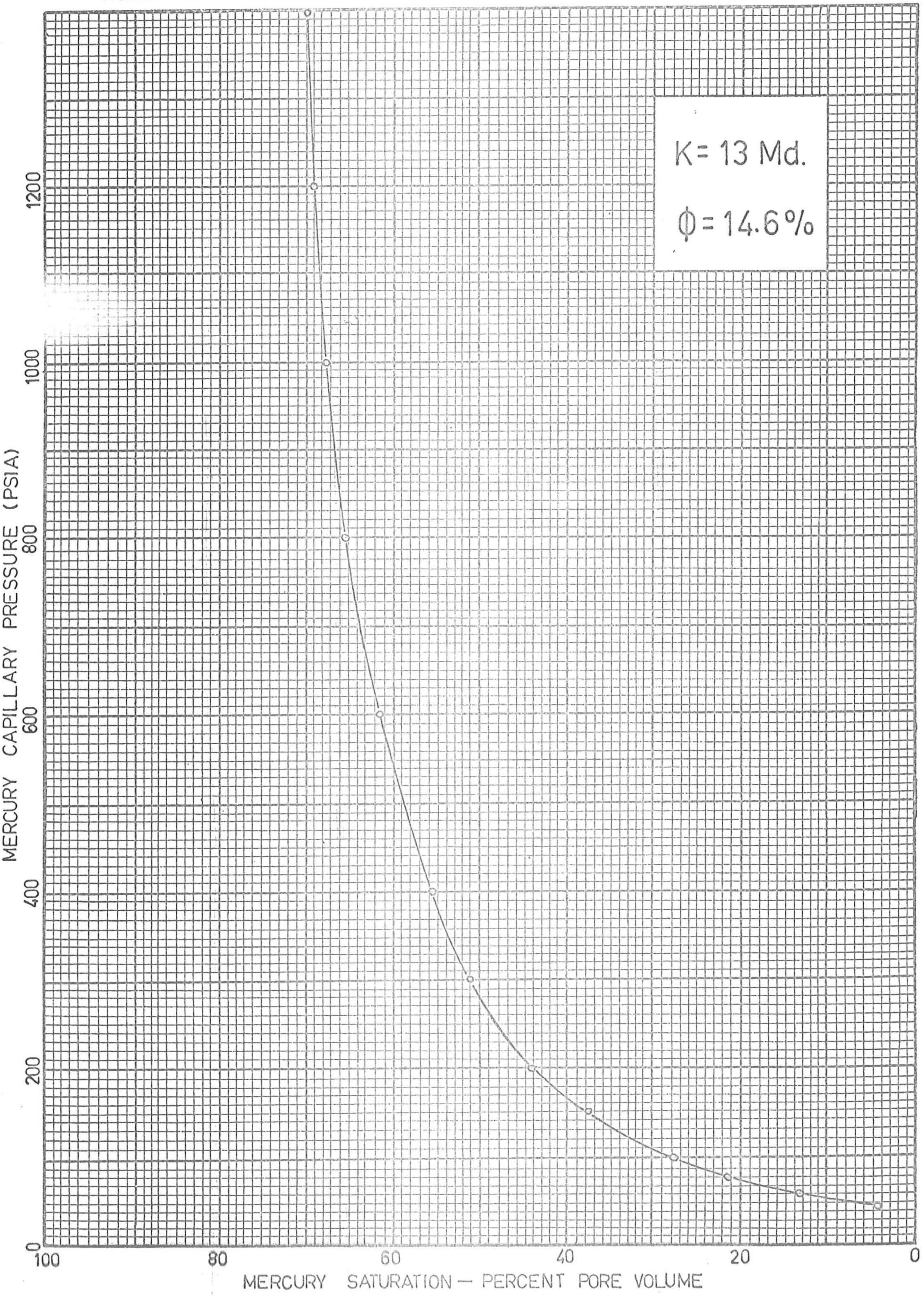


FIGURE 5

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2　　　SAMPLE DEPTH — 5656

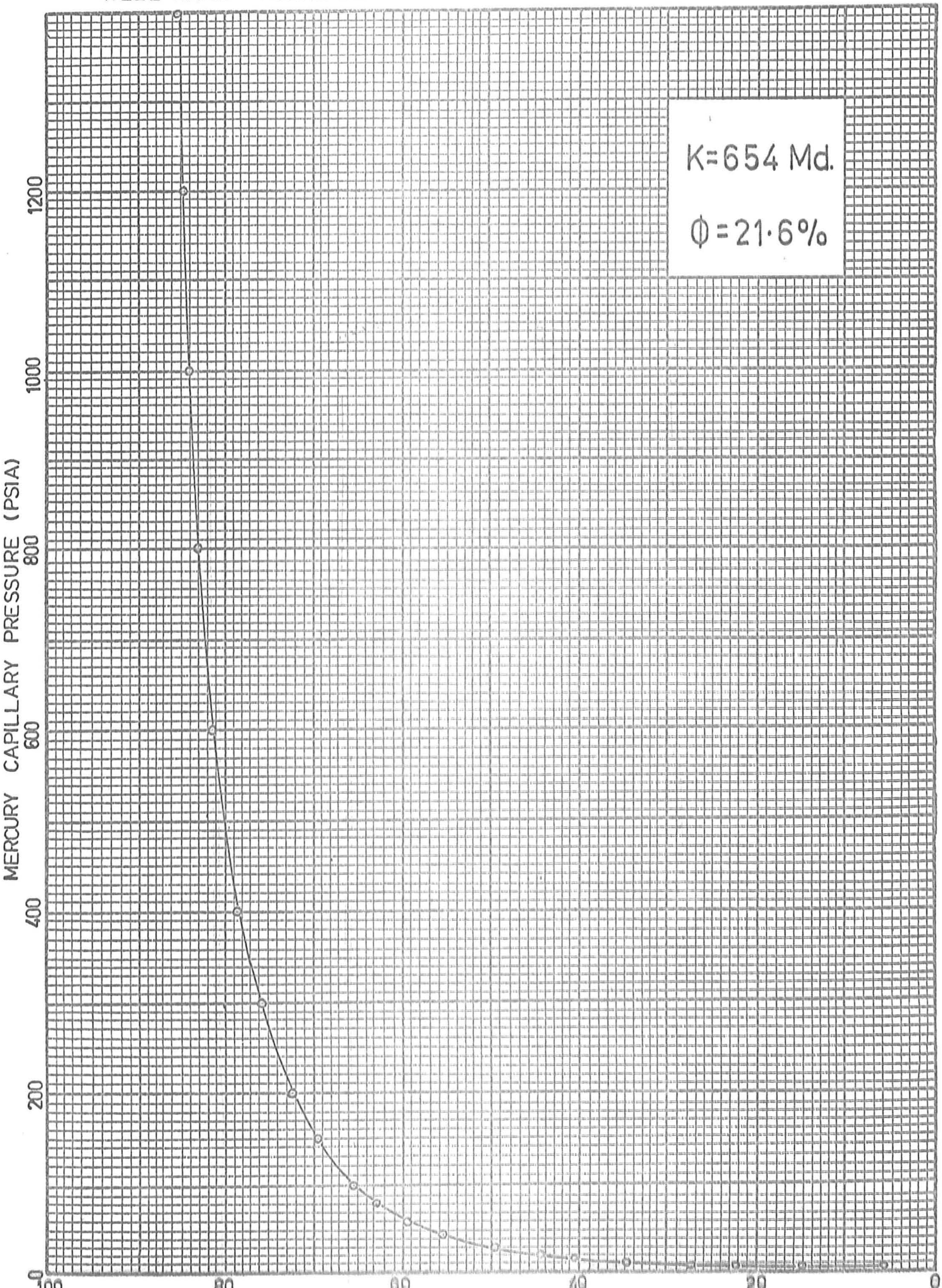


FIGURE 6

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH - 5656

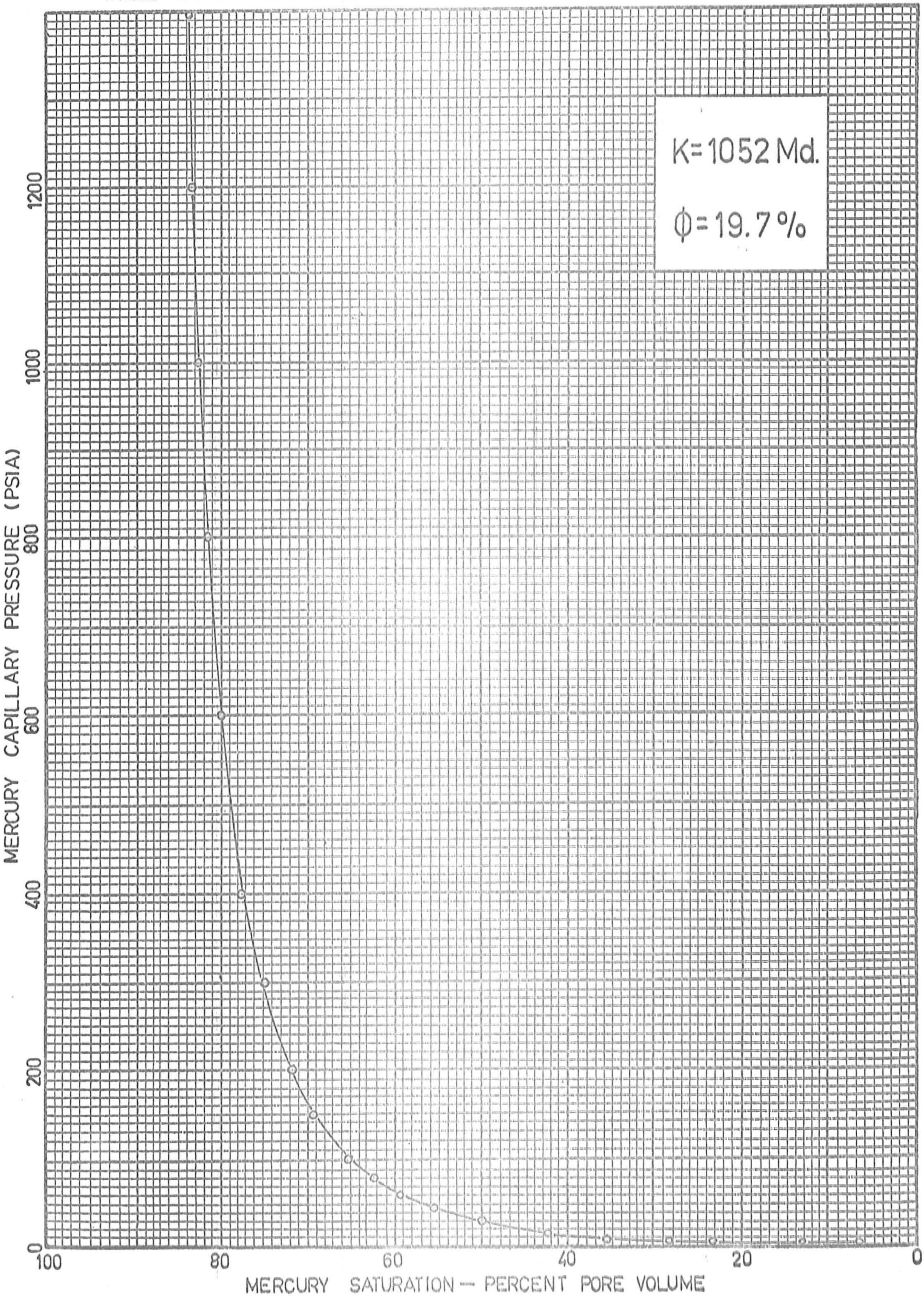


FIGURE 7

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5671

FIGURE 8

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2 SAMPLE DEPTH - 5681

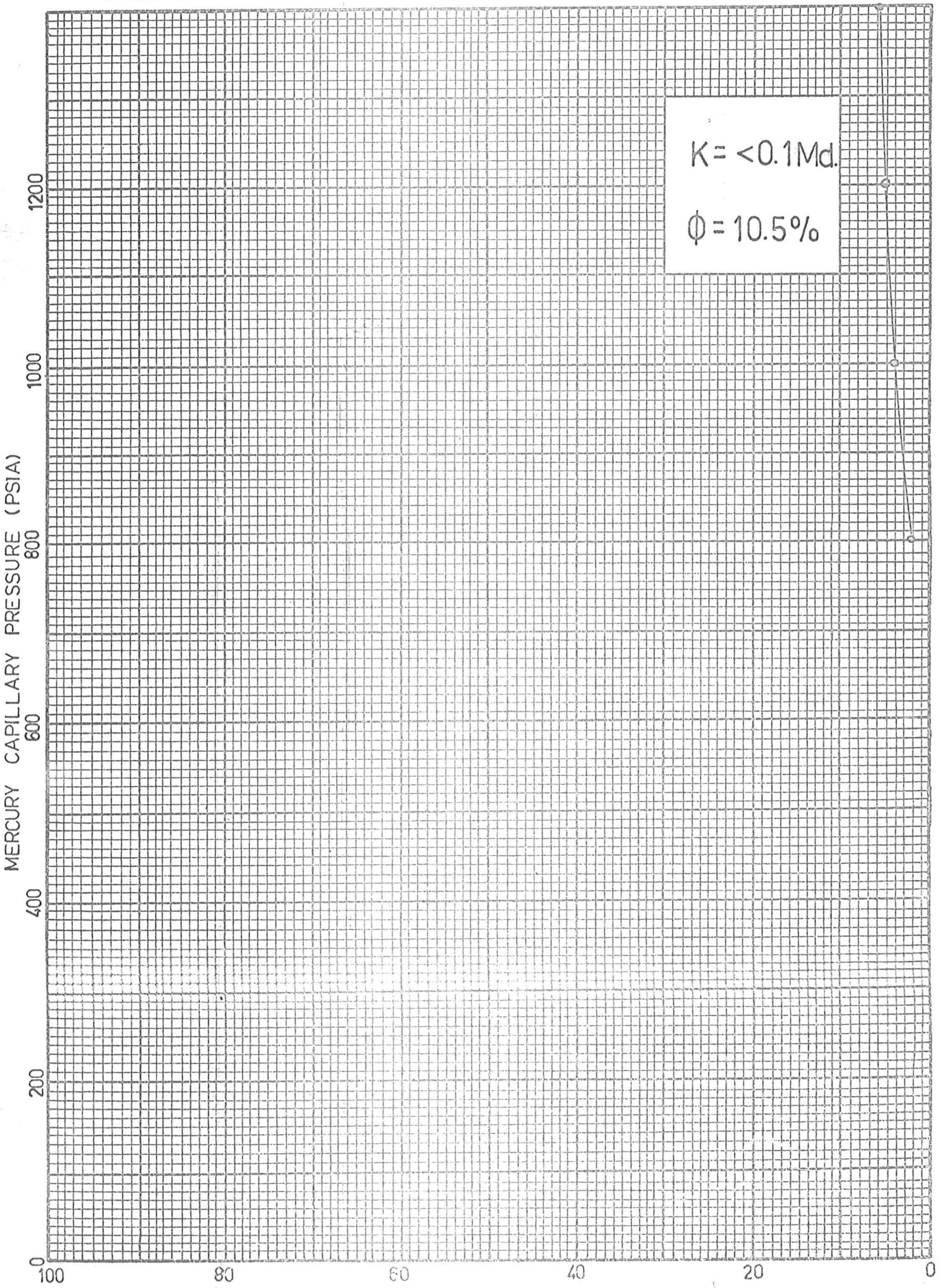


FIGURE 9

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH - 5686

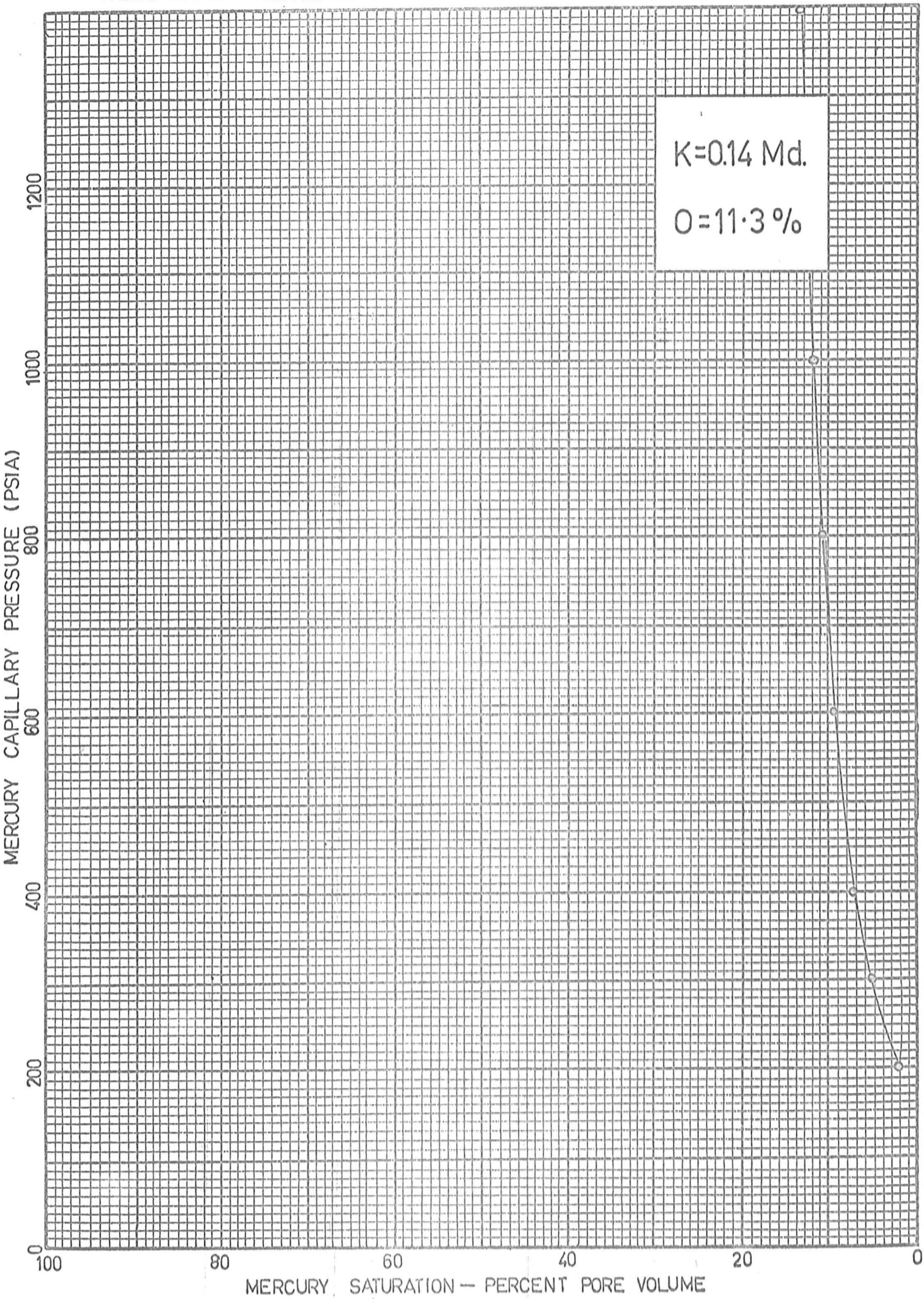


FIGURE 10

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5785

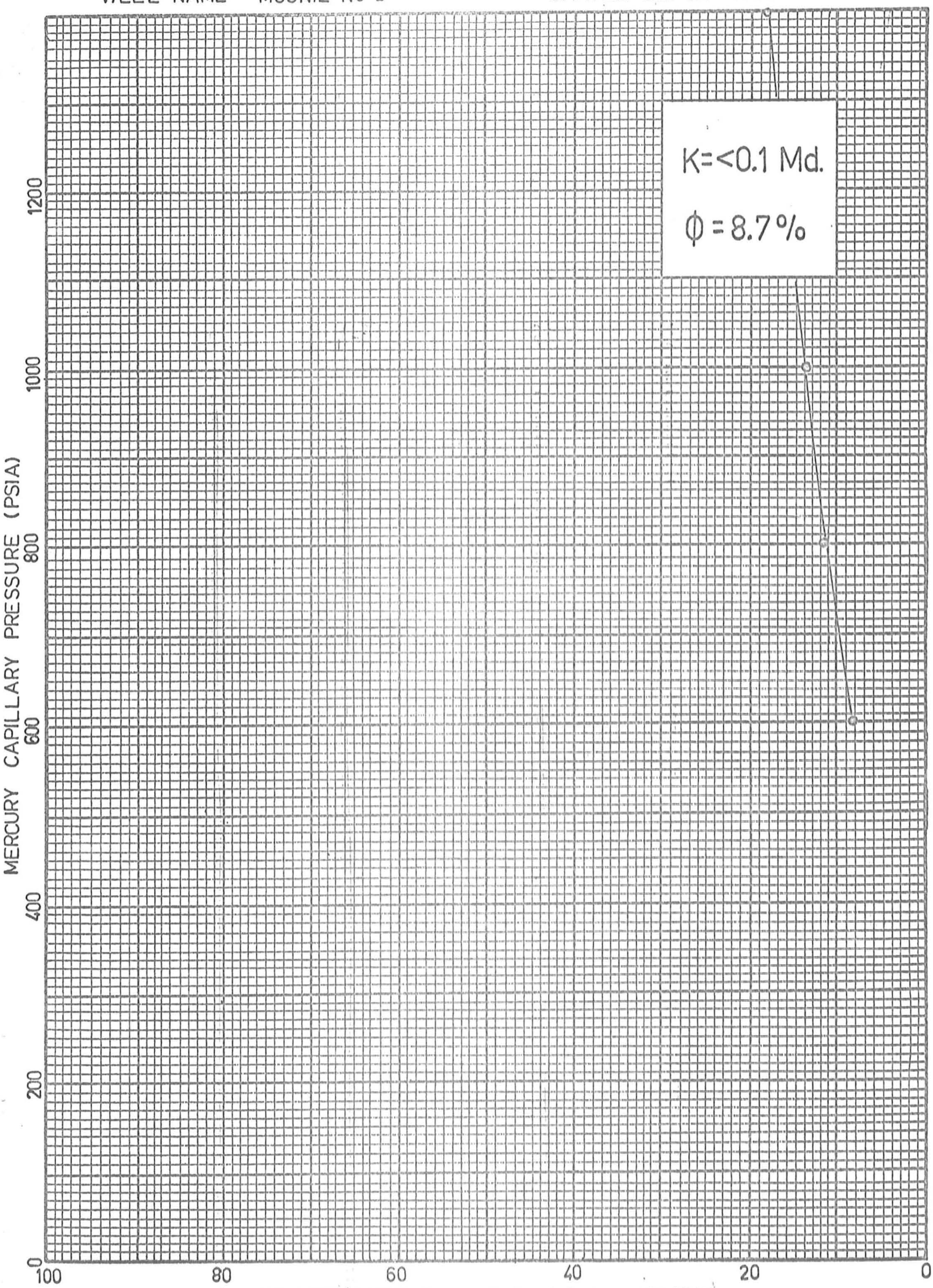


FIGURE 11

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2 SAMPLE DEPTH — 5823

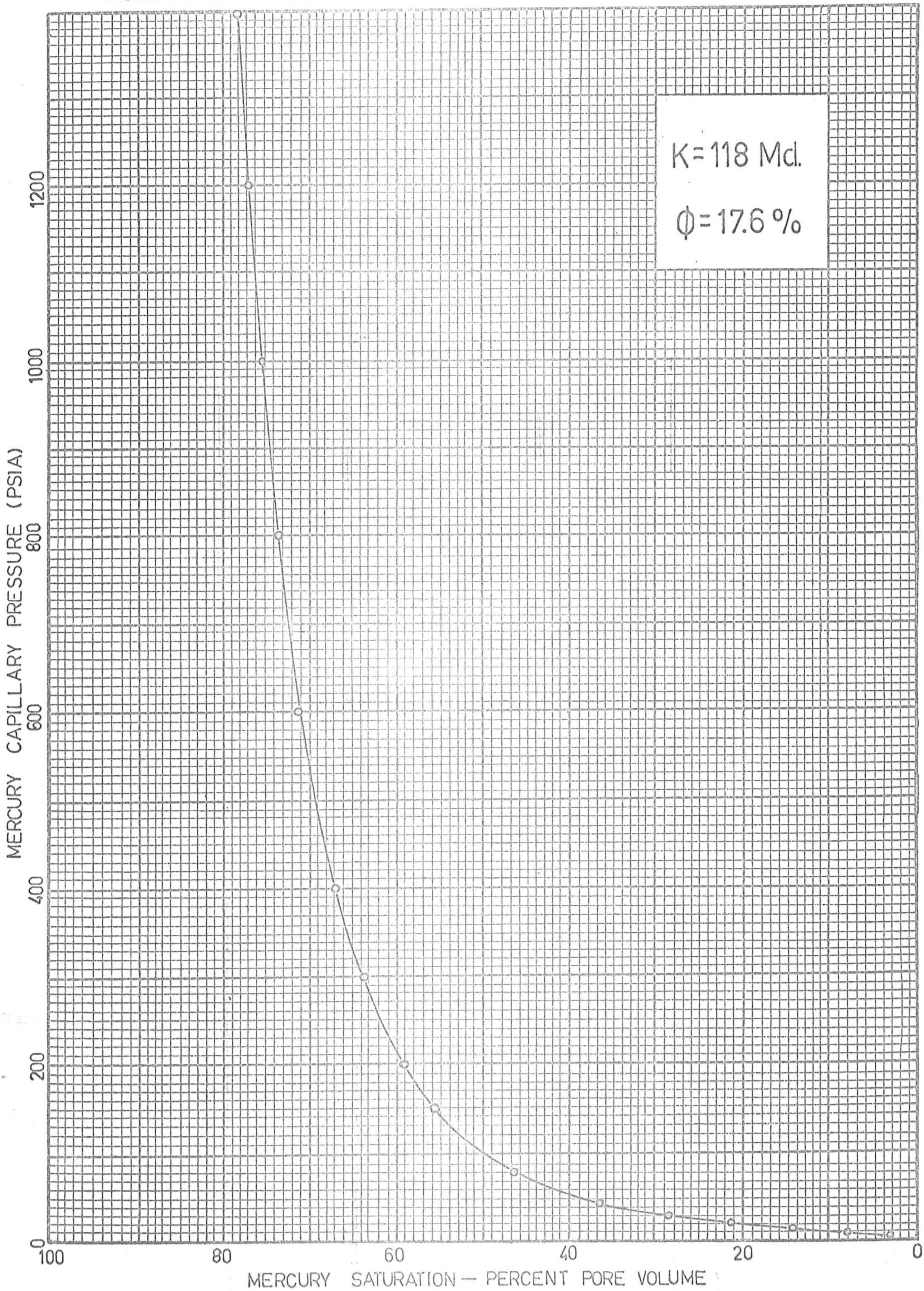


FIGURE 12

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5831

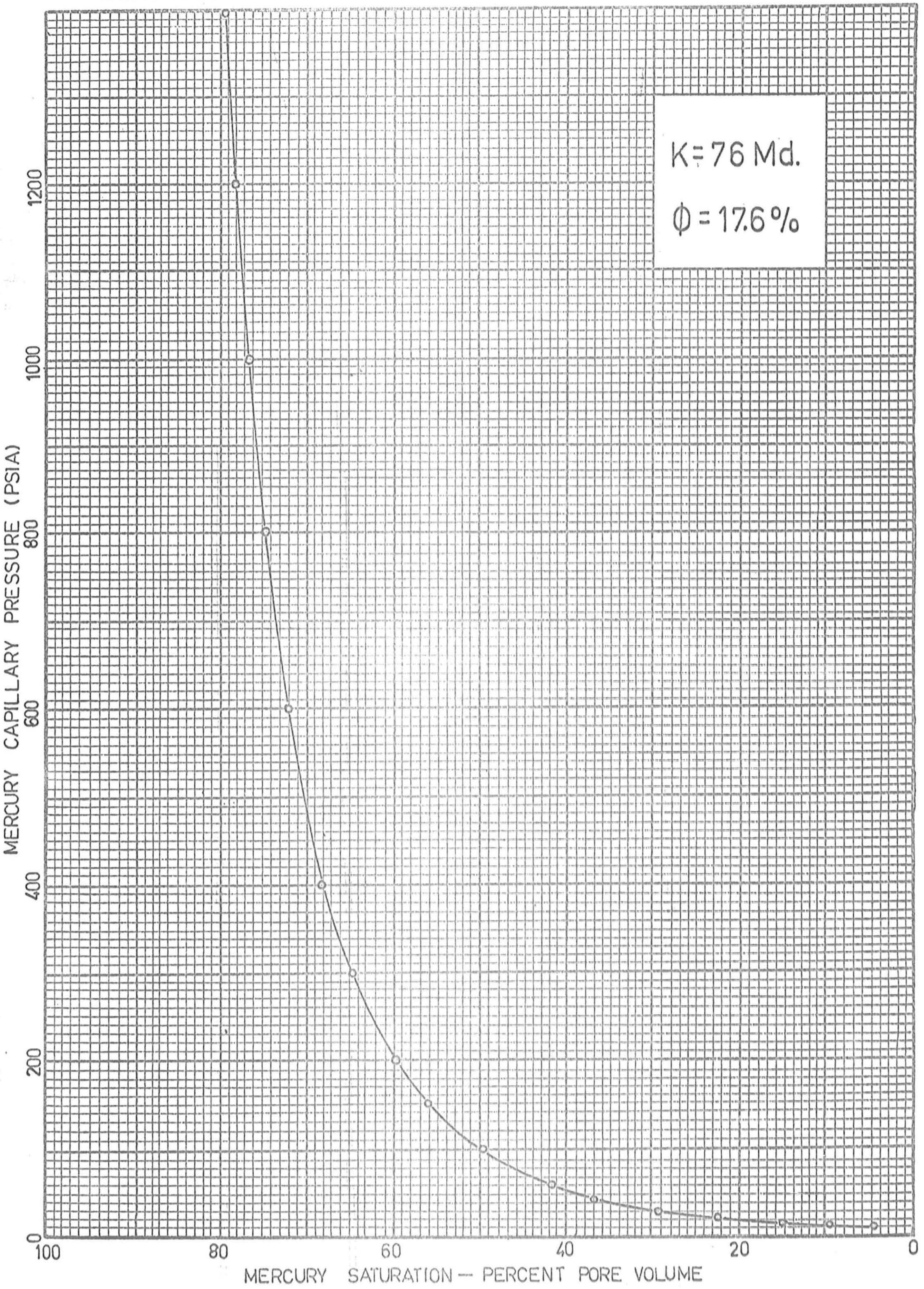


FIGURE 13

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5834

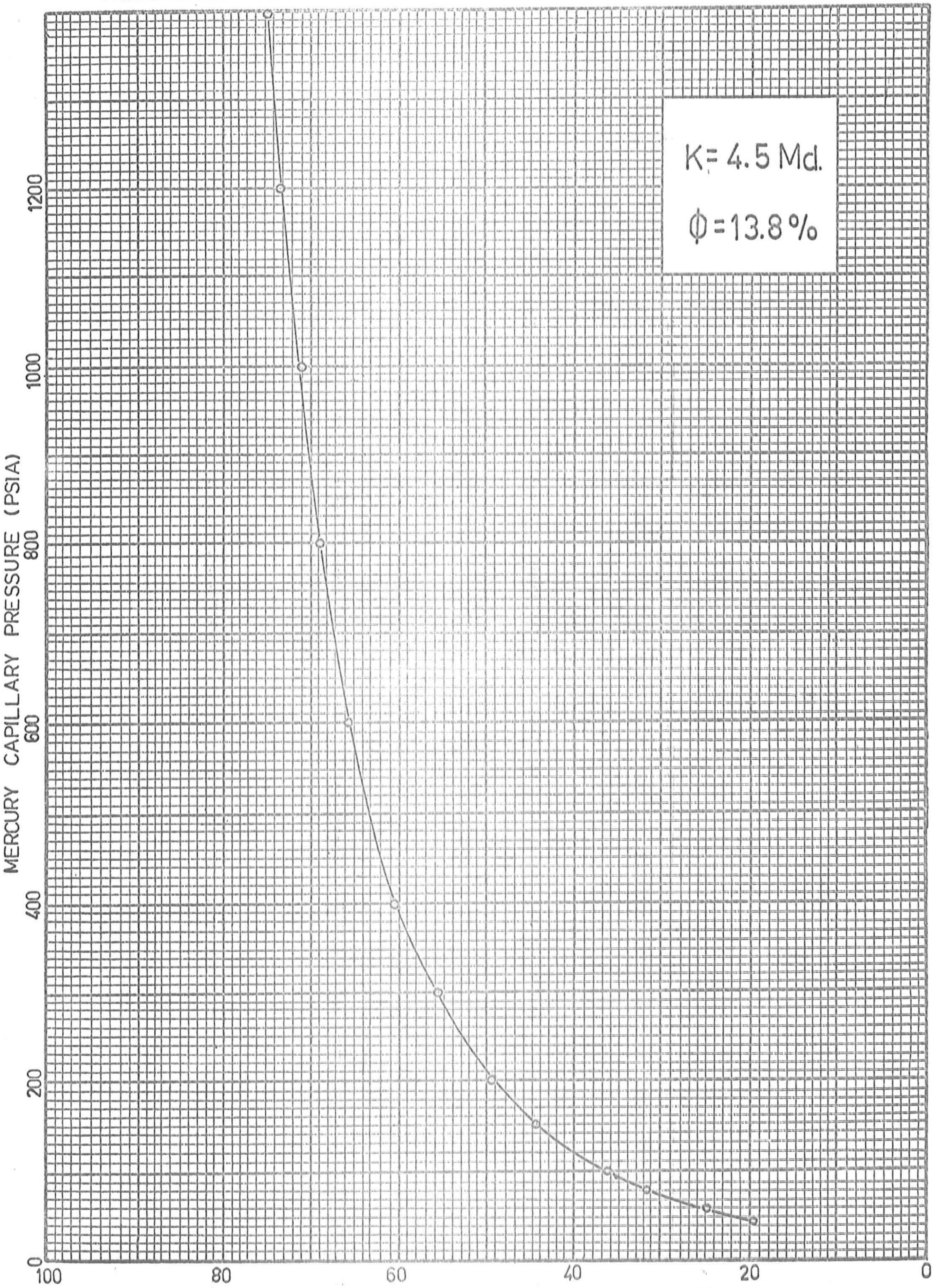


FIGURE 14

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5847

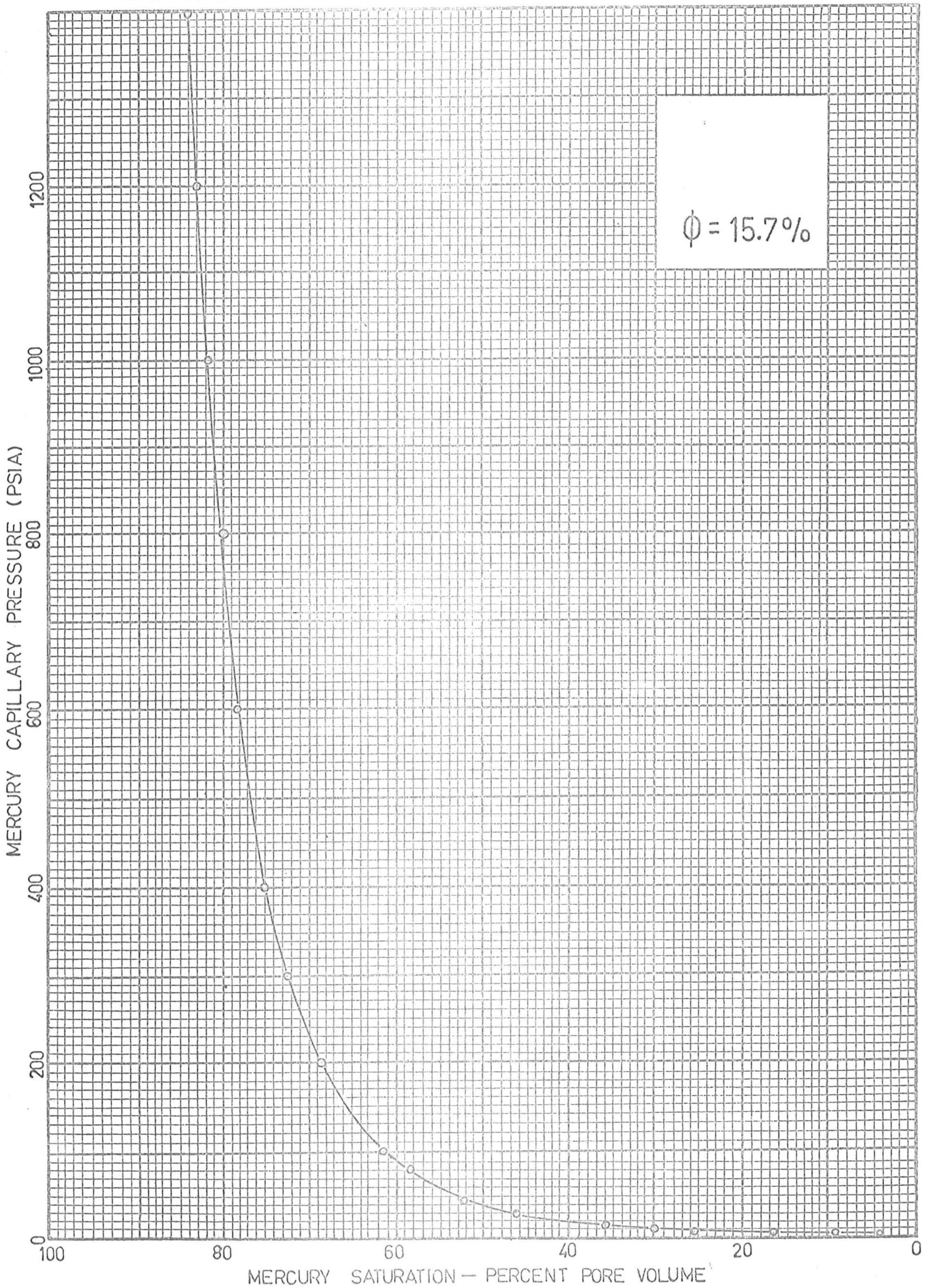


FIGURE 15

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2 SAMPLE DEPTH - 5855

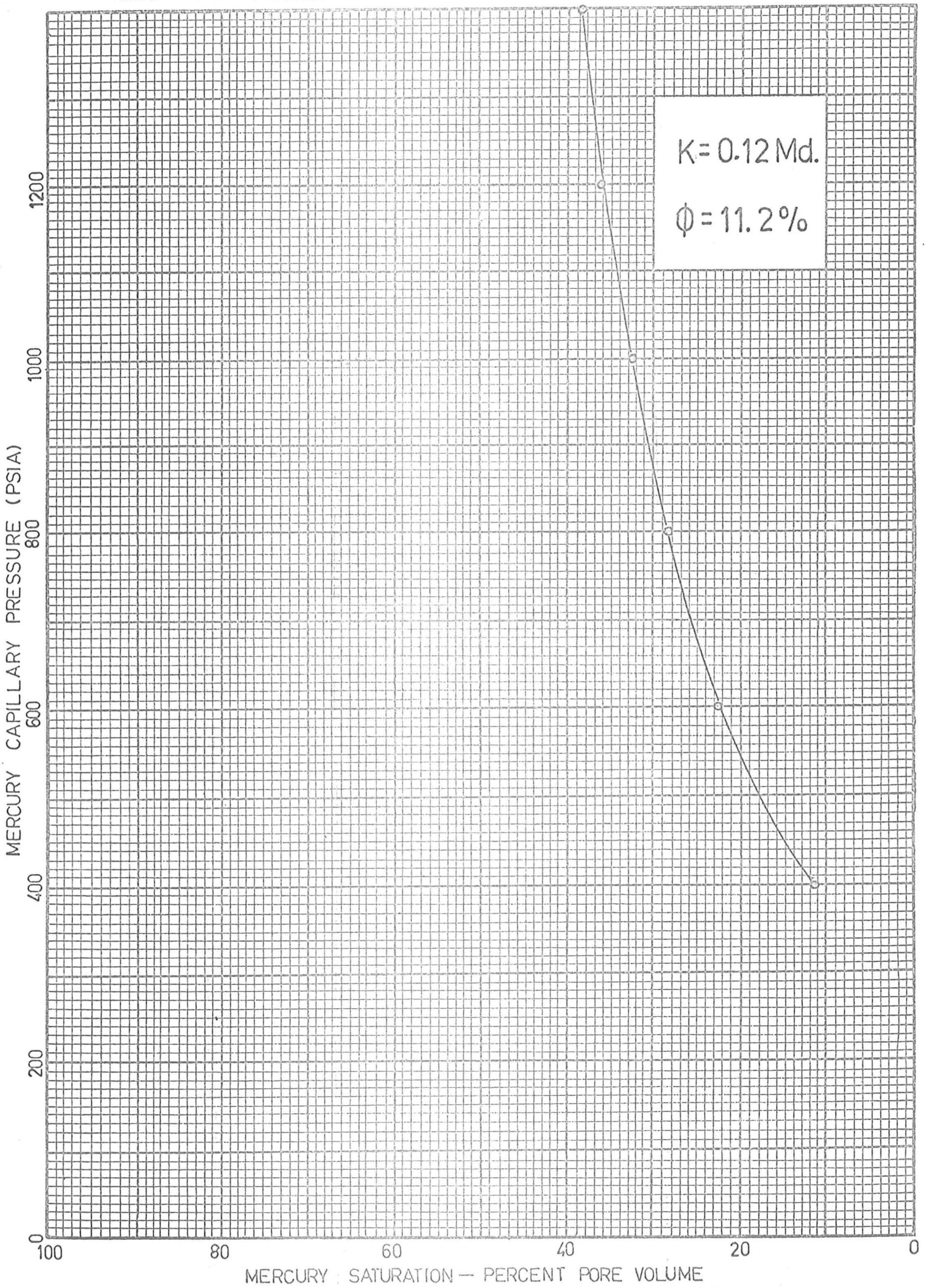


FIGURE 16

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2 SAMPLE DEPTH — 5863

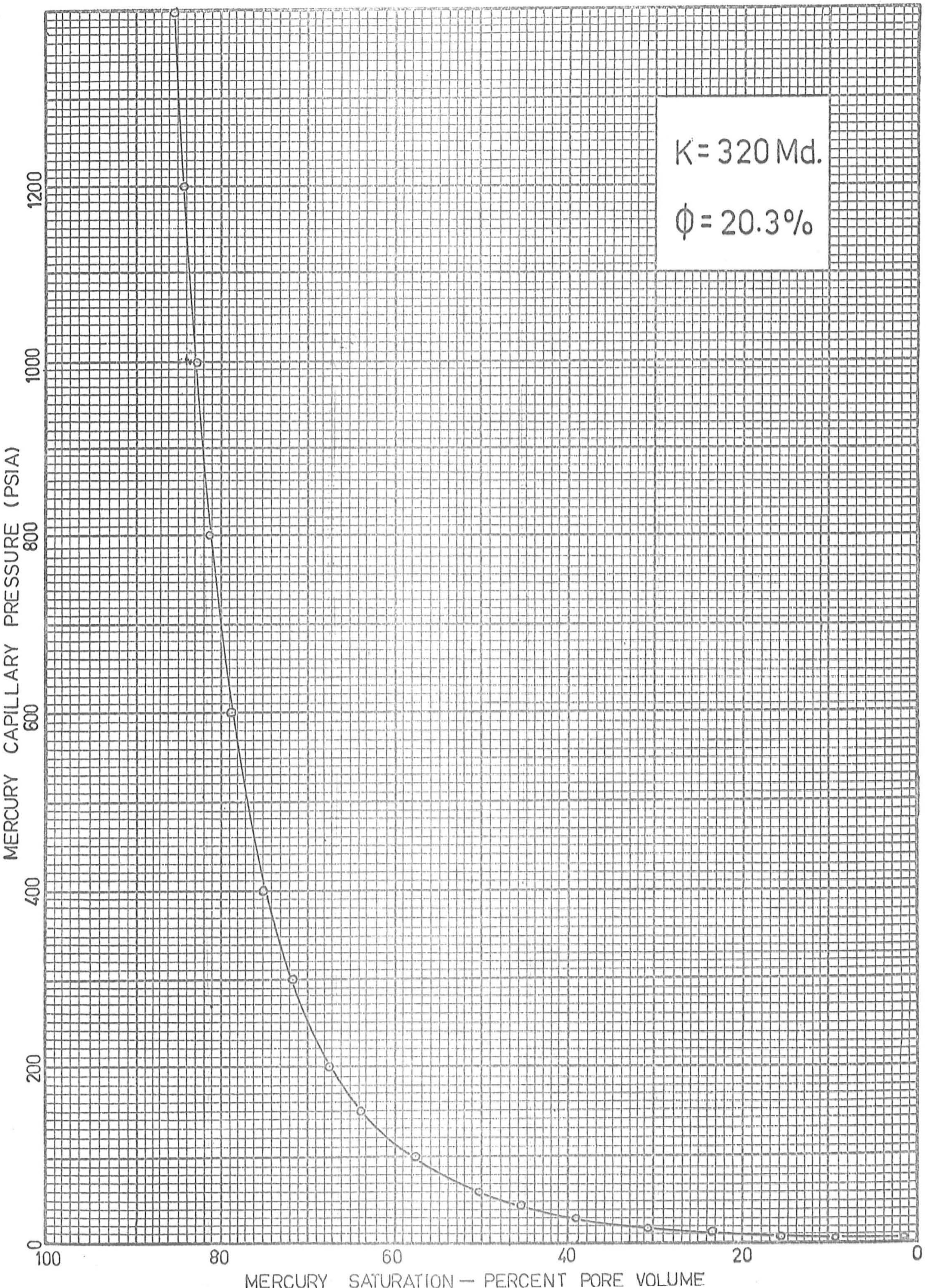


FIGURE 17

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No. 2 SAMPLE DEPTH — 5867

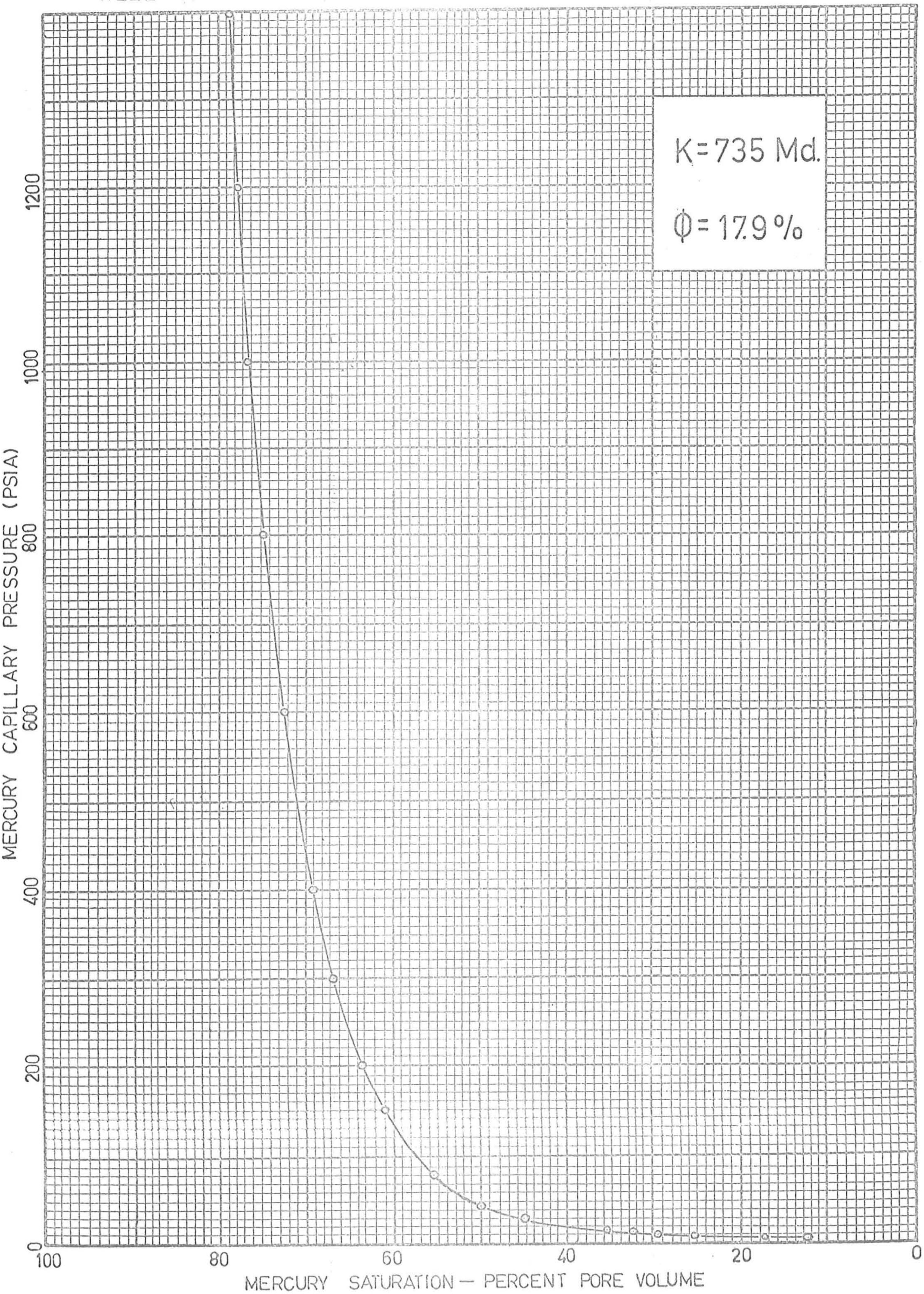


FIGURE 18

MERCURY CAPILLARY PRESSURE

WELL NAME — MOONIE No 2 SAMPLE DEPTH — 5877

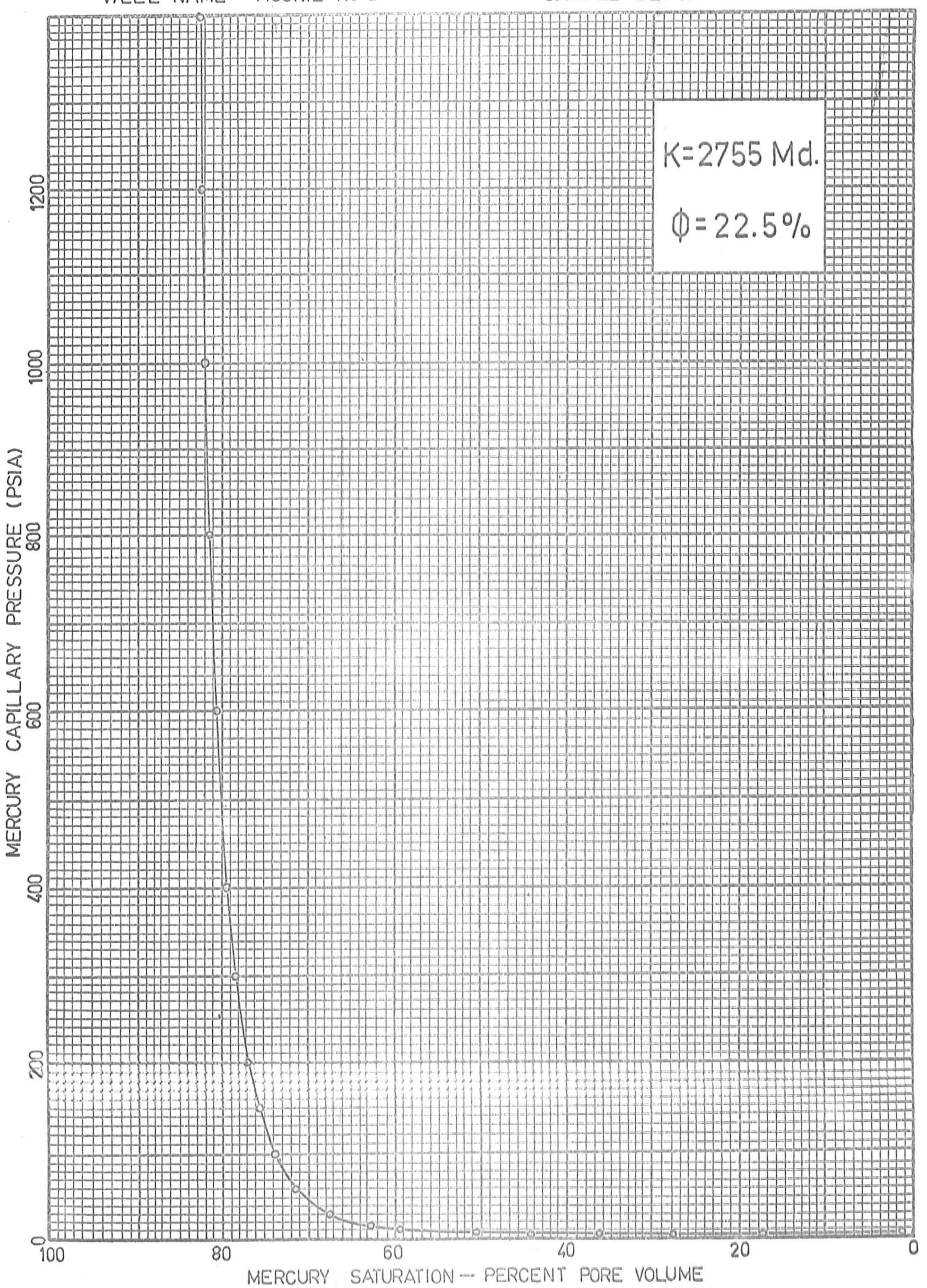
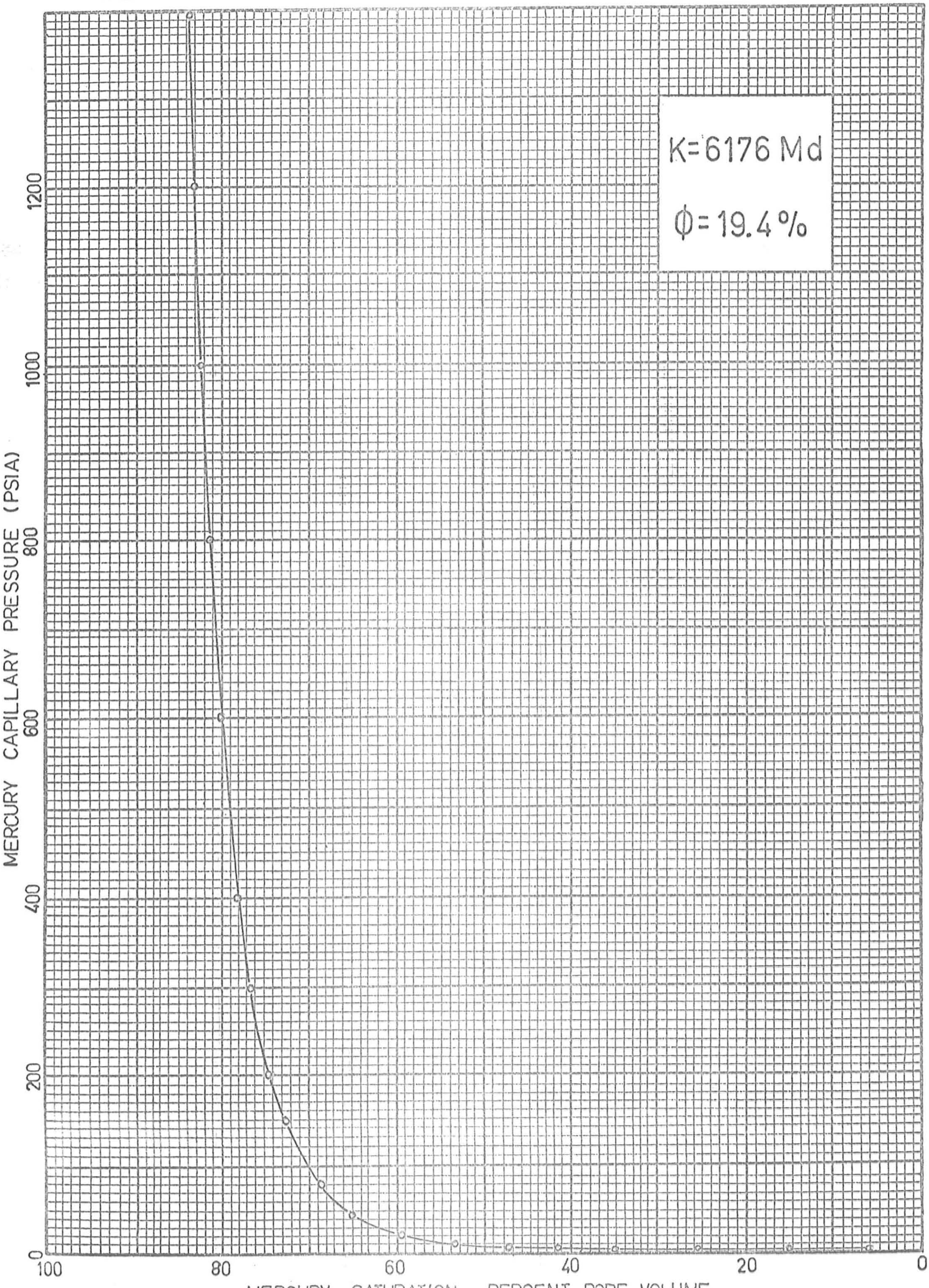
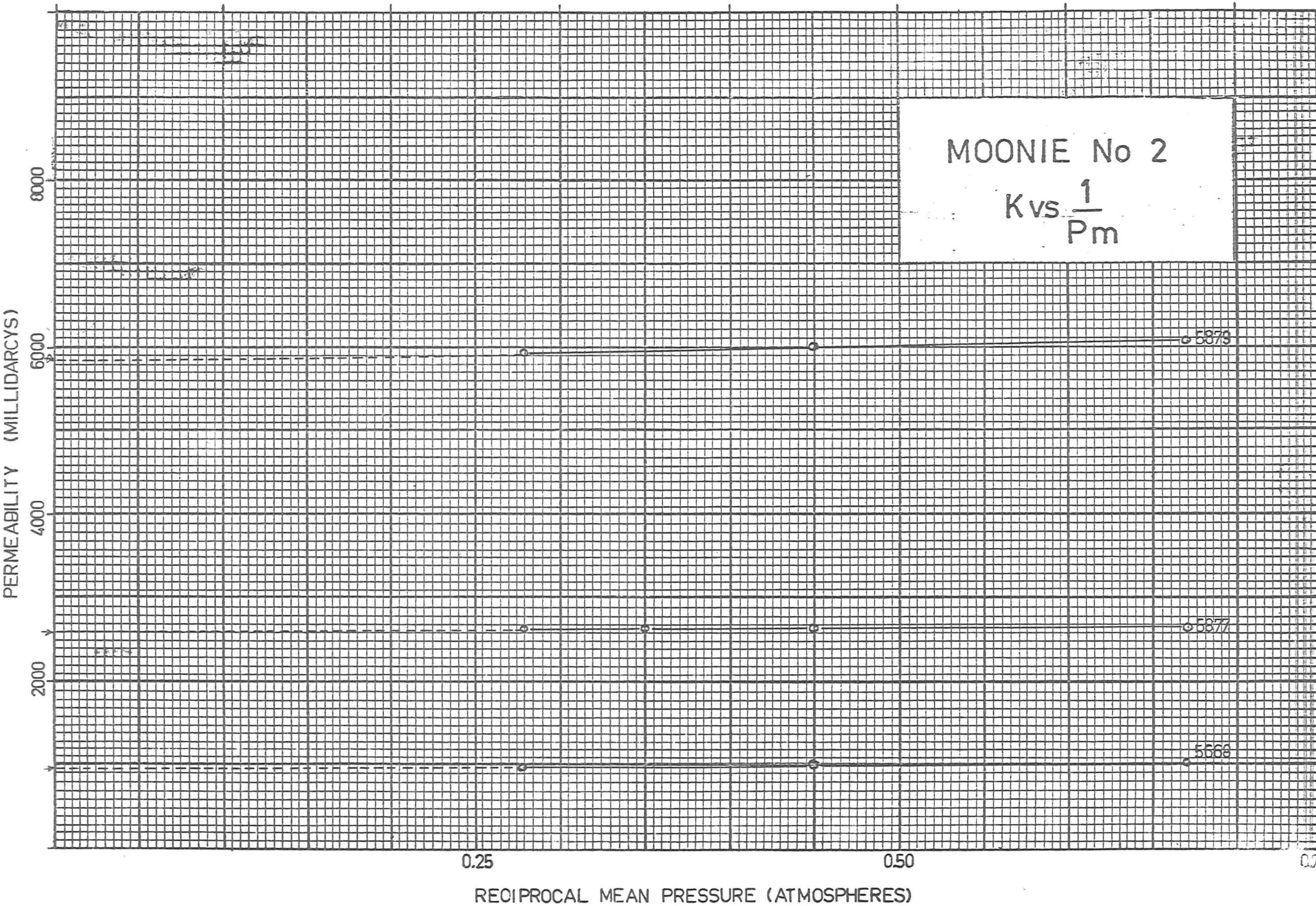


FIGURE 19

MERCURY CAPILLARY PRESSURE

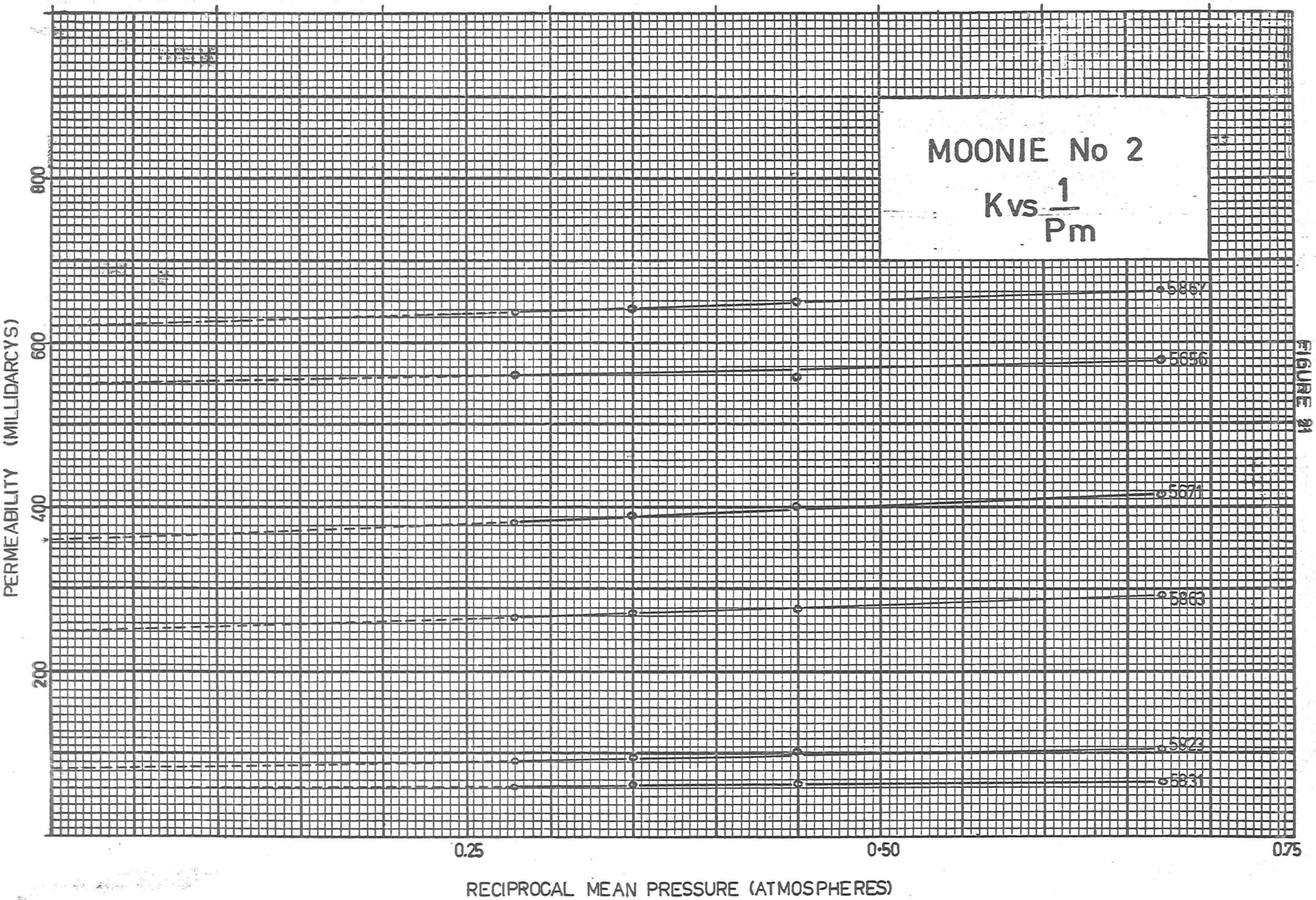
WELL NAME — MOONIE No. 2 SAMPLE DEPTH — 5879





MOONIE No 2
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
8000
6000
4000
2000
5879
5877
5668
0.25
0.50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)

FIGURE 20



MOONIE No 2
K vs 1/Pm
PERMEABILITY (MILLIDARCYS)
800
600
400
200
5867
5656
5671
5863
5823
5831
0.25
0·50
0.75
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)
FIGURE 21

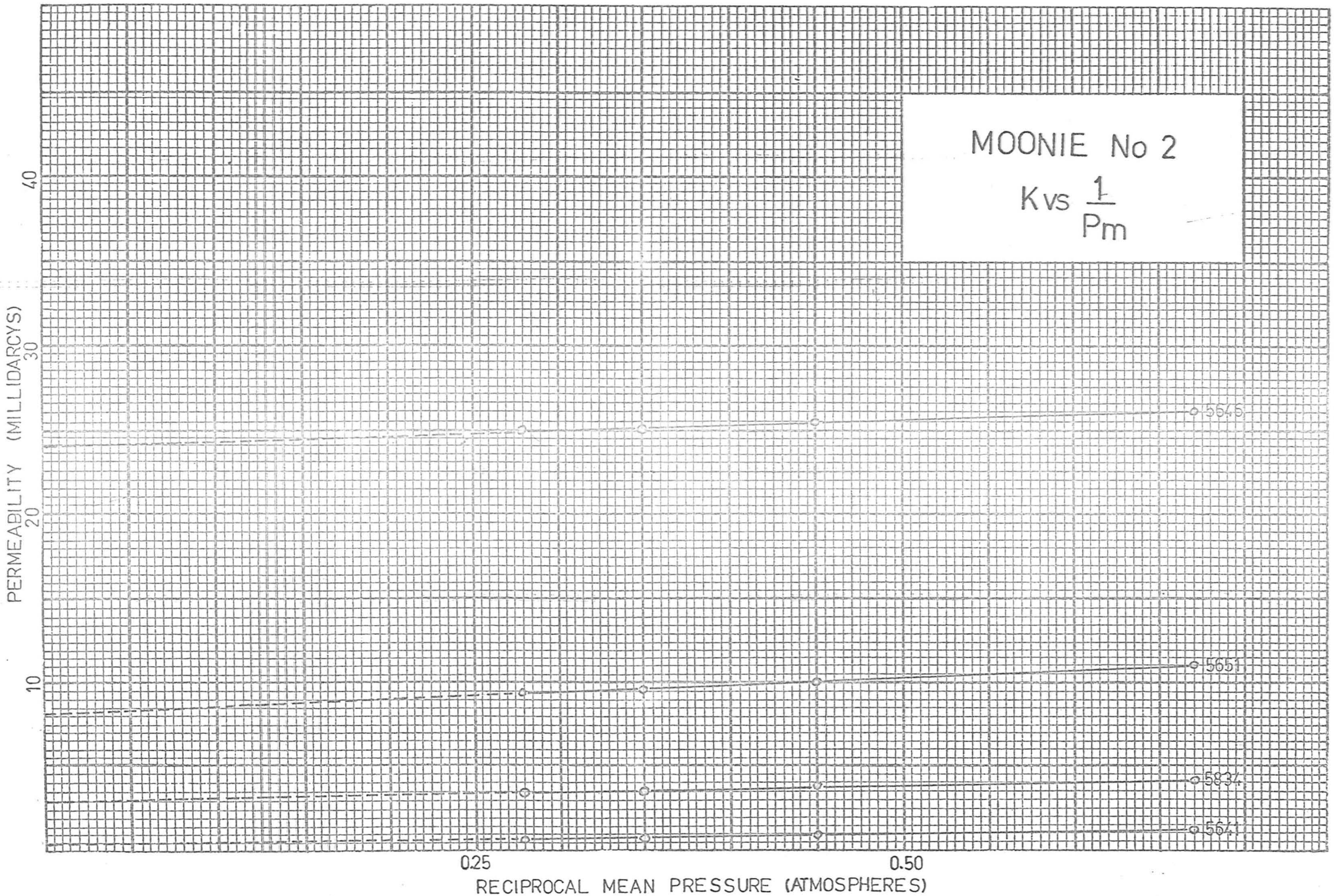

MOONIE No 2
K vs $\frac{1}{Pm}$
40
30
20
10
PERMEABILITY (MILLIDARCYS)
5646
5651
5834
5641
0.25
0.50
RECIPROCAL MEAN PRESSURE (ATMOSPHERES)

FIGURE 22

FIGURE 23

CORE LABORATORIES TYPE RESISTIVITY APPARATUS

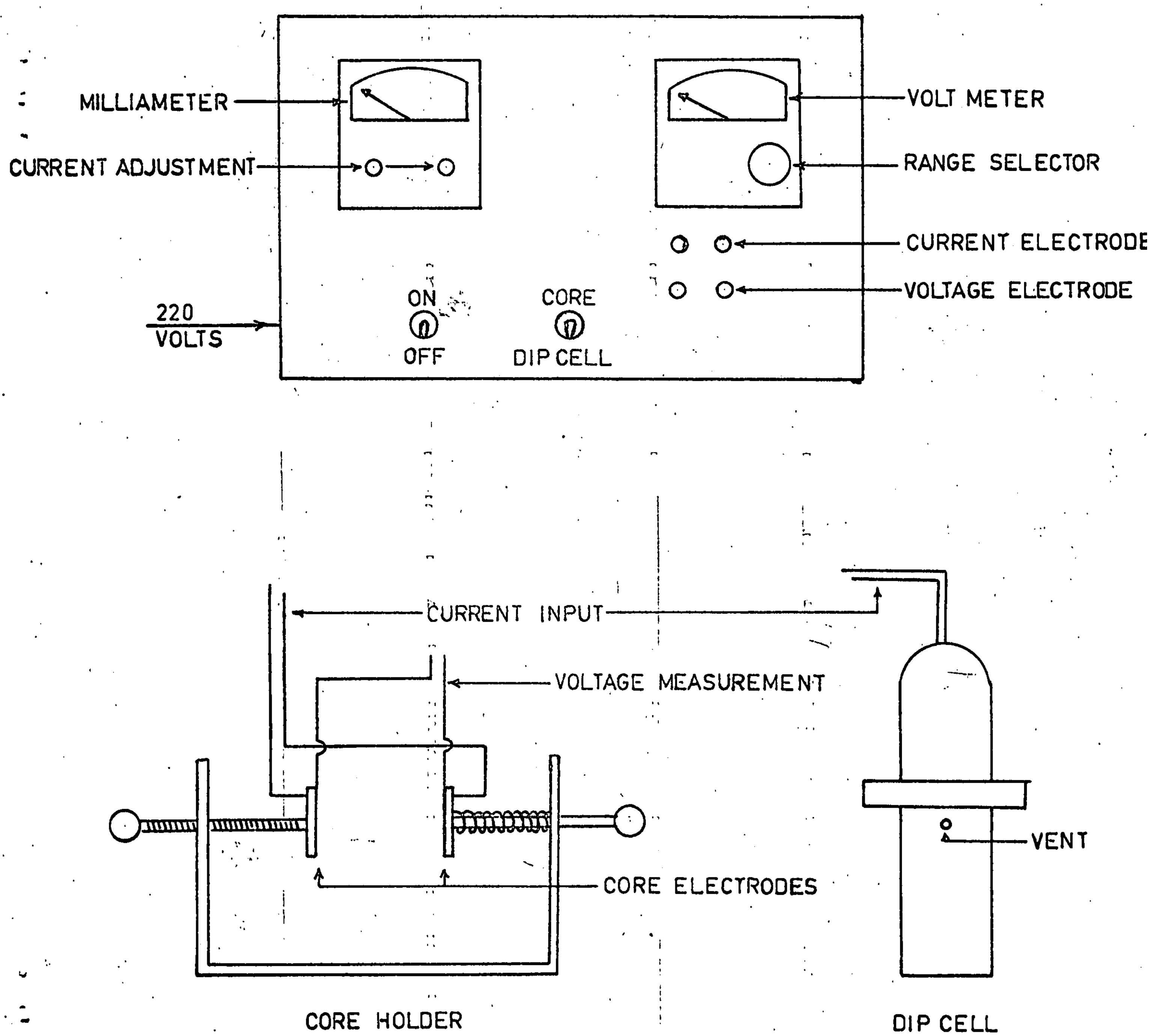


FIGURE 24

FORMATION FACTOR Vs POROSITY FRACTION

WELL NAME AND NUMBER- MOONIE No. 2

DEPTH INTERVAL - 5636-5879