STATOIL PRODUCTION LAB
SPECIAL CORE ANALYSIS
FILE NUMBER 050 34/10-2
050 P.5.12.10
REPORT # 1, 34/10-2

PETROLEUM ENGINEERING DEPT. OCT 1979

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1. SUMMARY

Checks on the quality of consultant routine core analysis and, where possible, log parameters, are made by cross-plotting with PROLAB's special core analysis data. GECO's routinely measured porosities are indicated to be in the range 0.5 to 1.0 P.U. too high.

A relationship between Ø and F at standard conditions for clean sand was found to be

$F = \phi^{-m}$ $\quad 1.9 < m < 2.0$ (Statfjord formation)

A Waxman - Smits approach for shaley sand indicated

$F^{*} = \phi^{-m^{*}}$ $\quad 1.8 < m^{*} < 1.9$ (Brent formation)

$1.9 < m^{*} < 2.0$ (Statfjord formation)

1. INTRODUCTION

A study was done on various horizontal core analysis parameters of well 34/10-2, Brent formation and Statfjord formation, the latter being the predominant area of analysis.

After defining representative sections of the reservoir by means of $\emptyset$ - K_L plotting, various quality checks on the consultant routine core measurements, and comparisons of log and lab data, could be made. Finally, porosity versus formation factor, both at atmospheric conditions, was plotted to attempt to define an "m" or "m^*" value for use in the petrophysical analysis.

3 RESERVOIR DESCRIPTION

The Jurassic sandstone was divided into four zones in this study.

The Brent formation comprises the Massive sand (Etive) zone and the Mica sand (Rannoch). The Etive is made up of coarse grained, fairly unconsolidated clean sands with good porosity and permeability. The Rannoch at the top is similar to the Etive but gradually increases in mica content with increasing depth.

The Statfjord formation comprises the Nansen and Ericsen zones, both consisting of clean to argillaceous sandstone interbedded with shale and coal.

Plots of KLCO, horizontal empirical liquid permeability as measured by Geco, versus PHEC, the Geco helium porosity, were made for each zone. (Figs 1-4)

Plugs representative of the zones were selected from these plots for analysis. The analysis is done mainly in the Statfjord formation, as work has been done previously on the Brent. (Lab report, 34/10-1, Brent sand, Jan 1979)

4. EXPERIMENTAL PROCEDURES

After the consultant (Geco) analysis had been performed, 37 well shaped 1 inch cylindrical plugs were cleaned in toluene and methanol , and dried (at 60°). Air permeabilities, and hence empirical liquid perms (KKLB) were obtained using Core Lab empirical correction for Klinkenberg, and Statoil measured helium porosities (PHE) were found using matrix cup/ Boyles' Law Helium-injection method. As an independent check on porosity, Ø saturation (PSAT) was measured gravimetrically using kerosene as the saturating fluid. Standard calibrations were made for all measurements.

Evacuation and saturation (1000 psi) with 60,000 ppm salinity degassed sodium chloride solution followed, measuring Co and Cw, the conductivity of 100 % saturated plug, and the conductivity of the saturating brine. Temperature was held to 22°C.

The plugs were salt extracted in a centrifuge extraction systems using methanol, dried at 60°C for 24 hours, and the process repeated at 90,000 ppm, and finally 120,000 ppm with Co in each case being measured along with Cw. Plugs were again salt extracted.

5 RESULTS DISCUSSION

Table 1 gives a listing of measured parameters with associated computer data numbers, plug numbers, and core depth. A nomenclature is found at the end of this report.

The accuracy of the lab porosity measurement is illustrated by the confirmation check PHE vs PSAT, fig 5, where two completely independent techniques for porosity measurement give good agreement.

5.1 Consultant (GECO) routine core analysis quality checks.

Poor agreement of PHE and PHEC (consultant lab porosity) is shown by fig. 6, obtaining.

$$PHE = 0.969\ PHEC - 0.20 \quad (r^2 = 0.985)$$
(in porosity units, P.U.)

This suggest that Geco porosities are 1.0 P.U. too high at 25 P.U., and 0.5 P.U. too high at 12 P.U. These discrepancies are outside the erro limits of the method.

Fig. 7, KLLB vs KLCO illustrates fair agreement of emperical liquid permeabilities. However, the measurement air permeability depends on the input air pressure. If this pressure was known from Geco's report a more thorough comparison could be made.

PROLAB's matrix densities (RMALB) distribution is shown in histogram , fig 8 and indicates 2.65 g/ml (2.63 ?) predominant. Plug 5 contains dolomite and plug D contains siderite.

The Geco matrix densities (RMAC) distribution for eleven fewer plugs is shown in fig. 9.

Fig 10 shows the composite cross-plot.

5.2 Log/Laboratory cross-checks.

Fig 11, PELG vs PHE, shows a plot of effective log porosity, after shaliness and hydrocarbon corrections have been performed, against lab helium porosity. If we assume some scatter due to inexact depth matching, (see appendix), we obtain an expected relationship where PHE is slightly higher than reservoir conditions PELG. This plot has better statistics on the petrophysical evaluation report, sep 1979.

Figs 12 and 13, RBLB vs PHE for each formation, describe sandstone lines with some mica influence. This description matches the geological microscope one.

RBLB is related to PHE by the following equation:

$$RBLB = RMALB - (RMALB - \rho mp)\,PHE \quad g/ml$$

where

RBLB = lab bulk density "in situ"
RMALB= lab matrix (grain) density
ρmf = density of mud filtrate in situ
PHE = lab helium fractional porosity

Two assumptions are made:

1. Ø reduction with N.C.P., net confining pressure, is negligible; the effect of taking this into account is to slightly increase the RBLB values by $\sim$ 0.01 g/ml, compensated for by a decrease an Ø, and the slope of PHE vs RBLB remains the same.

2. The fluid within the depth of investigation of the density log is 100 % mud filtrate.

For well 34/10-2

Temperature = 112.8 $^{\circ}$C
Fluid pressure = 441.4 bar
Rmf = 112.8 $^{\circ}$C

and according to Schlumberger "LIP" fig 8-5, we read ρmf = 0.985 g/ml

These in the above equation lead to:

RBLB = 2.65 - 1.67 PHE (SS)
RBLB = 2.71 - 1.73 PHE (LM)
RBLB = 2.86 - 1.88 PHE (DOL)

and these are overlain on the figures.

5.3 Porosity vs Formation Facttor

Figs 14 - 19 plot Co, conductivity of 100 % saturated plug versus Cw, conductivity of saturating brine. The "clean" points plot a line through the origin as espected, indicating constant F values independent of salinity. But some points intersect the negative Cw axis indicating "shale" effect where shale ions contribute to the Co measurement Hence it can be understood that the Archie "clean sand" approach can be used for analysis of 34/10-2 "clean" points. Hoyer and Shann (Exxon) suggested that

$$\frac{B_{max} \quad Qv}{Cw} \qquad 0.1$$

for "clean" points (SPWLA 16th symphosium, 1975, B).
So in this case ,

$$B_{max} \quad Qv < 0.1 \times 6 \cdot 3 \text{ mho m}^{-1}$$

$$B_{max} \quad Qv < 0.63 \text{ mho m}^{-1}$$

where the formation salinity is taken as 44,000 ppm NaCl equivalent, i.e. Cw = 6.3 mho m^{-1} at 22^{o}C, the temperature of measurement.

The reciprocal slopes of these lines, theoretically through the origin, are taken as the formation factor values, F44K, and these are plotted with PHE for 15 points (mainly Statfjord) in fig 20.

Most of the points fall within

$$F = \emptyset^{-m} \quad \text{where } 1.9 < m < 2.0$$

$F = \emptyset^{-2.0}$, and $F = \emptyset^{-1.90}$ are plotted in fig 20.

Shaley sands are defined where B_{max} Qv > 0.63 $mhom^{-1}$ and F^*, the shaley sandstone Formation Factor, is represented by

$$F^* = \frac{1}{Co} (B_{max} Qv + Cw)$$

and is calculated for 25 clean and shaley sands from the reciprocal slopes of the Co - Cw plots.

Figs 21 and 22 show PHE vs F^* for Brent and Statfjord formations, for 5 and 20 points respectively.
For the Brent, most points fall within

$$F^* = \emptyset^{-m^*} \quad \text{where } 1.8 < m^* < 1.9$$

and for the Statfjord, the limits of m^* are

$$1.9 < m^* < 2.0$$

Qv values from this method are presented in a later report, Qv for 34/10-2.

Net overburden pressure would result in a very slight increase in m or m^* value. A first assumption of m = 2.0 in log analysis would seen reasonable. A second report with simulated reservoir pressures of Ø and F should confirm this.

CONCLUSIONS

The results of this first report on 34/10-2 show some discrepancy in helium porosity between Geco and Statoil, with Geco reading high by 1.0 P.U. at 25 P.U. and 0.5 P.U. at 12 P.U.

Empirical liquid permeabilities are in fair agreement.

Log and lab porositty comparison have too much scatter to be useful.

Clean sands plot an F vs Ø relationship of

$$F = \emptyset^{-m} \quad \text{where } 1.90 < m < 2.0$$

10 samples were indicated to be shaley-sands, as defined by $B_{max}\ Qv > 0.63\ mhom^{-1}$, and clean and shaley sands plot an F^* vs Ø relationship of

$$F^* = \emptyset^{-m^*}$$

where $1.8 < m^* < 1.9$ Brent formation
$1.9 < m^* < 2.0$ Statfjord formation

m and permeability change with overburden stress will be presented in a later report.

APPENDIX CORE/LOG DEPTH MATCHING

Two cores were cut in Brent fm. and six in Statfjord formation. The coremeasured rock properties have been correlated to logs. The correlations are listed below:

Core No. 1	Interval	:	3031	-	3041.2
	Recovery	:	100%		
	Log Interval (CPI)	:	3030	-	3040.2
Core No. 2	Interval	:	3103	-	3113.6
	Recovery	:	100%		
	Log Interval (CPI)	:	3100.5	-	3111.1
Core No. 3	Interval	:	3338.0	-	3345.2
	Recovery	:	100%		
	Log Interval (CPI)	:	3337	-	3344.2
Core No. 4	Interval	:	3345.2	-	3363.5
	Recovery	:	89%		
	Log Interval (CPI)	:	3344.7	-	3360.5
Core No. 5,6,7,8	Interval	:	3363.5	-	3390.1
	Recovery	:	100%		
	Log Interval (CPI)	:	3360.5	-	3387.1

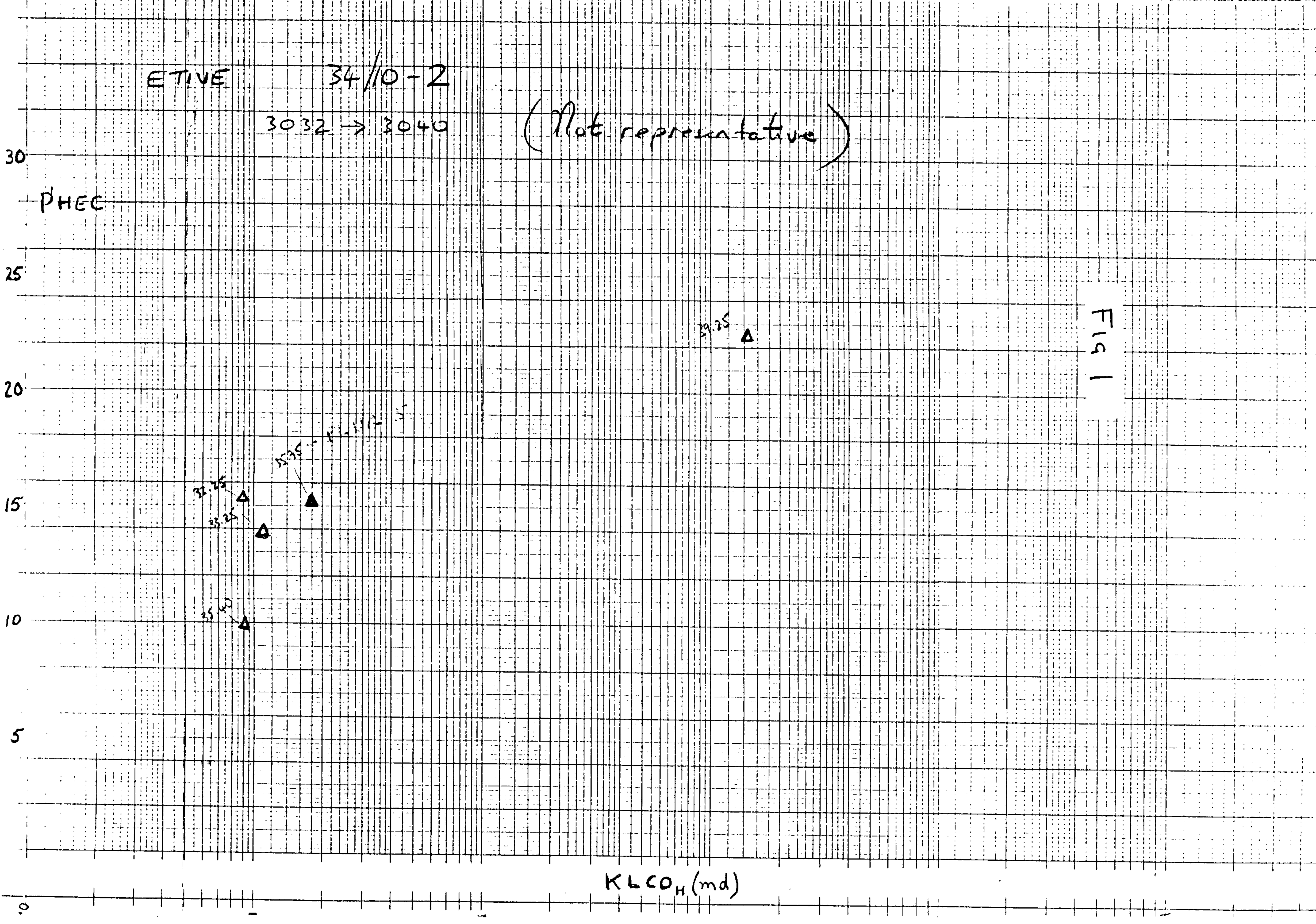
Nomenclature

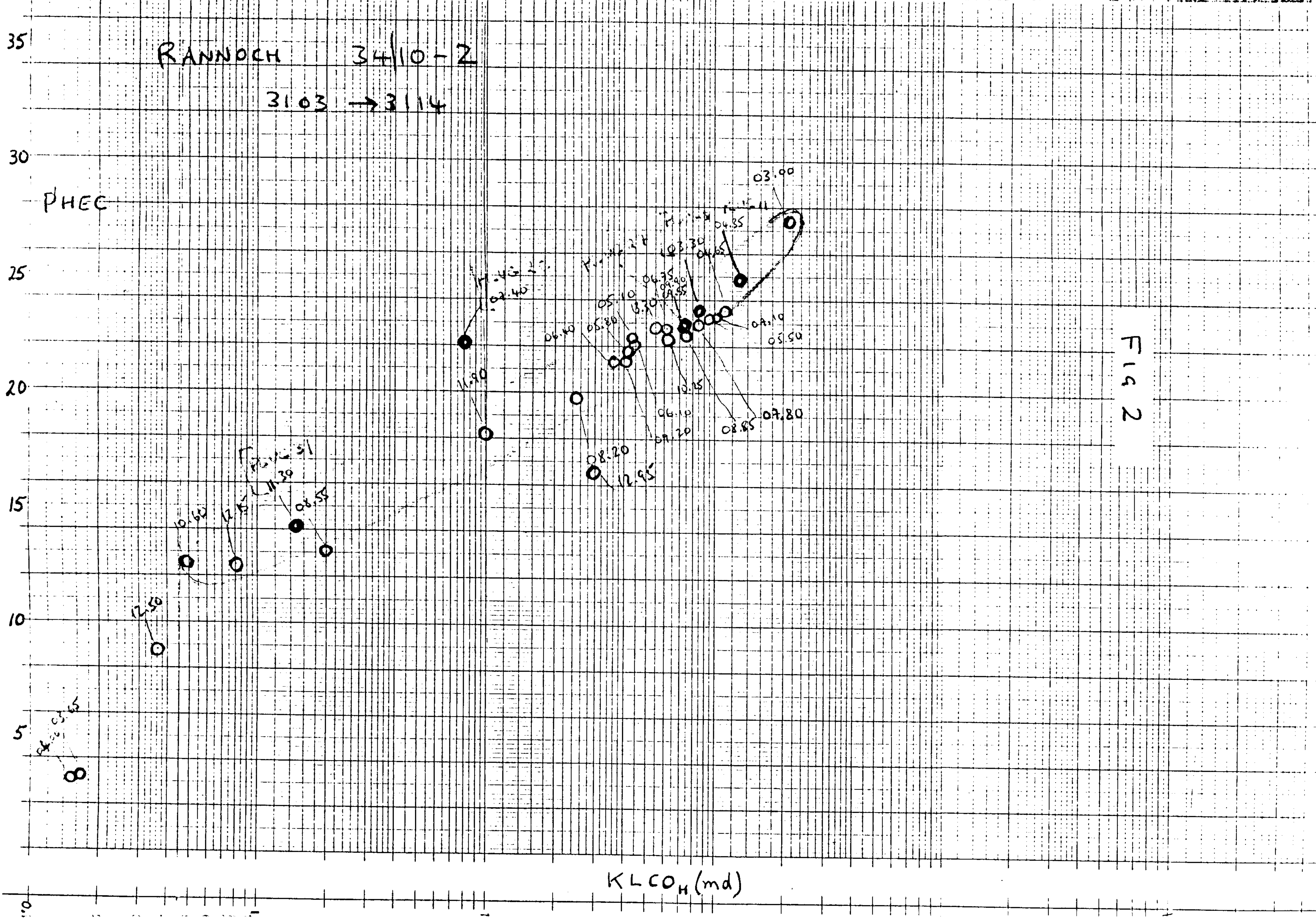
a	=	coefficient in F-Ø relation.
a*	=	coefficient in F* -ø relation.
A	=	gradient coefficient in Y=AX+B computer linear regression curve fit.
B	=	constant in Y=AX+B computer linear regr. curve fit.
B max	=	maximum equivalent conductance of clay exchange cations (sodium) (mho cm^2 meq^{-1})
Co	=	specific conductance of rock 100% saturated in aqueous solution (mho m^{-1}).
Cw	=	specific conductance of aqueous solution (mhom^{-1}).
C2	=	correlation coefficient in Y= AX+B computer linear regression curve fit, = r^2
DATA NO	=	computer number given to plug in sequence.
Depth	=	driller's depth of core (m).
F	=	formation factor.
F *	=	formation resistivity factor for shaley sand.
KLLB	=	Statoil empirical liquid perm. (md).
KLCO	=	Consultant (GECO) empirical liquid perm. (md).
m	=	porosity exponent/lithology factor (cementation facto
m*	=	porosity exponent/lithology factor in F* -ø relation.
PELG	=	effective Statoil log porosity after shaliness and hydrocarbon corrections performed.
PHE	=	Statoil helium porosity.
PHEC	=	consultant helium porosity (GECO).
PLUG	=	plug number associated with depth.
PSAT	=	Statoil kerosene saturation porosity.

Qv	=	volume concentration of clay exchange cations(equiv/li
RBLB	=	Statoil lab bulk density in situ (see page 6) (g/ml).
RBLG	=	log bulk density reading (g/ml).
RMAC	=	consultant matrix density (g/ml) (GECO).
RMALB	=	Statoil matrix density (g/ml) (GECO).
Rmf	=	invaded zone "mud filtrate" resistivity (Ohm-m).
Ro	=	specific resistance of rock (Ohm-m) 100% saturated in aqueous solution at laboratory temperature and pressure.
Rw	=	specific resistance of aqueous solution (Ohm-m) at laboratory temperature and pressure.
ρmf	=	density of mud filtrate in situ (g/ml).
ρhc	=	density of hydrocarbon in situ (g/ml).
ρsatfl.	=	density of saturating kerosene solution in PSAT calculations.
VB	=	bulk volume (ml.) (mercury displacement method).
VG	=	grain volume (ml).
W	=	dry weight of plug(g).

TABLE 1

ZONE	DATA	CORE DEPTH	PLUG	KLLB	KLCO	PHE	PSAT	PHEC	PELG	RBLB	RMALB	RMAC	F44K	F*	Description: irregularities from clean sandstone
ETIVE	1	3035.75	5	1.30	1.80	.149	.149	.153	.090	2.49	2.75	2.78	1.50	1.50	Shale laminations, dol.cem
RANNOCH	2	3103.30	8	88.0	86.0	.235	.226	.236	.265	2.27	2.67	2.68	1.50	15.5	sl.shaley, trace mica
	3	3104.35	11	132.	131.	.240	.242	.249	.230	2.26	2.66	2.67	1.50	13.8	a/a
	4	3107.40	20	2.20	8.00	.213	.219	.222	.140	2.29	2.65	2.66	1.50	17.4	Shale streaks
	5	3109.90	27	78.0	71.0	.226	.225	.228	.130	2.29	2.67	2.66	1.50	14.0	sl.shaley, trace mica
	6	3111.30	31	0.75	1.50	.138	.145	.141	.160	2.43	2.66	2.68	33.4	33.4	cleanish, mica, chipped
NANSEN	7	3338.40	38	120.	163.	.199	.197	.208	.190	2.30	2.63	2.66	24.0	24.0	trace kaolinite
	8	3342.10	D	8.40	0.15	.123	.015	.015	.125	2.55	2.77	2.50	1.50	1.50	heavy mineral, siderite ?
	9	3344.70	55	2.50	3.80	.132	.131	.136	.136	2.44	2.66	2.66	1.50	52.0	sl.shaley,mica,kaolinite
	10	3345.10	E	23.5	0.15	.156	.015	.015	.165	2.39	2.65	2.50	1.50	1.50	kaolinite
	11	3347.60	63	1070	1260	.196	.190	.209	.210	2.31	2.63	2.65	1.50	19.8	sl.trace shale
ERICSEN	12	3351.30	74	0.46	0.90	.095	.096	.096	.095	2.53	2.69	2.71	86.2	86.2	cleanish,mica,kaolinite
	13	3354.05	78	0.39	0.90	.144	.143	.145	.095	2.41	2.65	2.67	55.1	55.1	cleanish,trace,kaolinite
	14	3354.10	G	0.52	0.15	.129	.015	.015	.095	2.45	2.66	2.50	1.50	1.50	sl.shaley, mica
	15	3355.70	83	4.80	5.40	.168	.172	.185	.150	2.36	2.63	2.67	32.4	32.4	
	16	3355.70	H	3.70	0.15	.169	.015	.015	.165	2.37	2.66	2.50	1.50	1.50	sl.shaley
	17	3357.30	I	25.0	0.15	.180	.015	.015	.170	2.38	2.68	2.50	1.50	1.50	trace pyrite
	18	3357.45	88	124.	142.	.197	.193	.201	.185	2.30	2.62	2.64	22.7	22.7	trace mica
	19	3358.55	91	342.	360.	.201	.208	.215	.200	2.30	2.62	2.65	18.9	18.9	a/a
	20	3361.20	99	53.0	51.0	.195	.189	.194	.180	2.31	2.63	2.64	26.2	26.2	a/a
	21	3364.35	102	55.0	58.0	.182	.184	.194	.175	2.33	2.63	2.65	25.5	25.5	a/a,trace kaolin
	22	3364.50	J	59.0	0.15	.174	.015	.015	.165	2.35	2.63	2.50	1.50	1.50	
	23	3365.40	105	26.0	28.0	.128	.122	.128	.170	2.45	2.66	2.65	1.50	47.8	sl.shaley,calc.cement
	24	3365.45	K	75.0	0.15	.193	.015	.015	.170	2.33	2.65	2.50	1.50	1.50	
	25	3368.00	106	20.0	19.0	.192	.187	.197	.120	2.32	2.64	2.67	25.8	25.8	trace mica
	26	3372.00	112	137.	130.	.219	.215	.234	.210	2.27	2.63	2.66	19.4	19.4	a/a
	27	3372.20	L	93.0	0.15	.216	.015	.015	.210	2.28	2.64	2.50	1.50	1.50	
	28	3374.15	118	0.15	0.67	.079	.078	.088	.090	2.52	2.65	2.67	94.0	94.0	calc.cement, kaolinite
	29	3374.25	120	3.30	4.00	.138	.138	.153	.100	2.40	2.63	2.65	1.50	53.5	trace shale, kaolinite
	30	3378.40	M	0.15	0.15	.146	.015	.015	.130	2.39	2.63	2.50	1.50	1.50	kaolinite
	31	3378.60	126	1.70	2.00	.145	.143	.155	.150	2.41	2.65	2.66	37.5	37.5	sl.trace shale,mica,kaolinite.
	32	3380.20	N	15.0	0.15	.183	.015	.015	.190	2.32	2.62	2.50	1.50	1.50	sl.shaley
	33	3380.70	132	14.5	13.0	.147	.150	.160	.200	2.39	2.63	2.64	1.50	46.1	sl.shaley,mica
	34	3384.05	140	0.64	0.64	.169	.165	.175	.080	2.37	2.65	2.68	1.50	43.2	trace shale,mica,kaolinite
	35	3388.90	143	2.40	3.00	.176	.172	.182	.150	2.36	2.65	2.67	35.0	35.0	
	36	3389.95	146	300.	302.	.227	.220	.237	.220	2.25	2.63	2.67	16.5	16.5	
	37	3390.00	O	0.15	0.15	.165	.015	.015	.230	2.37	2.65	2.50	1.50	1.50	sl.shaley
NO MEASUREMENT INDICATORS:				0.15	0.15		0.015	0.015				2.50	1.50	1.50	


ETIVE 34/10-2
3032 → 3040
(Not representative)
PHEC
30
25
20
15
10
5
0
32.25
33.25
35.35
35.40
39.25
KLCO$_H$ (md)
Fig 1


RANNOCH 34/10-2
3103 → 3114
PHEC
KLCO_H (md)
35
30
25
20
15
10
5
03.00
04.35
03.30
04.65
07.40
11.90
06.40
05.80
05.10
06.35
07.10
05.50
12.25
06.10
07.20
08.85
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12.95
08.55
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10.60
12.50

Fig 2

NANSEN 34/10-2

3338 → 3350

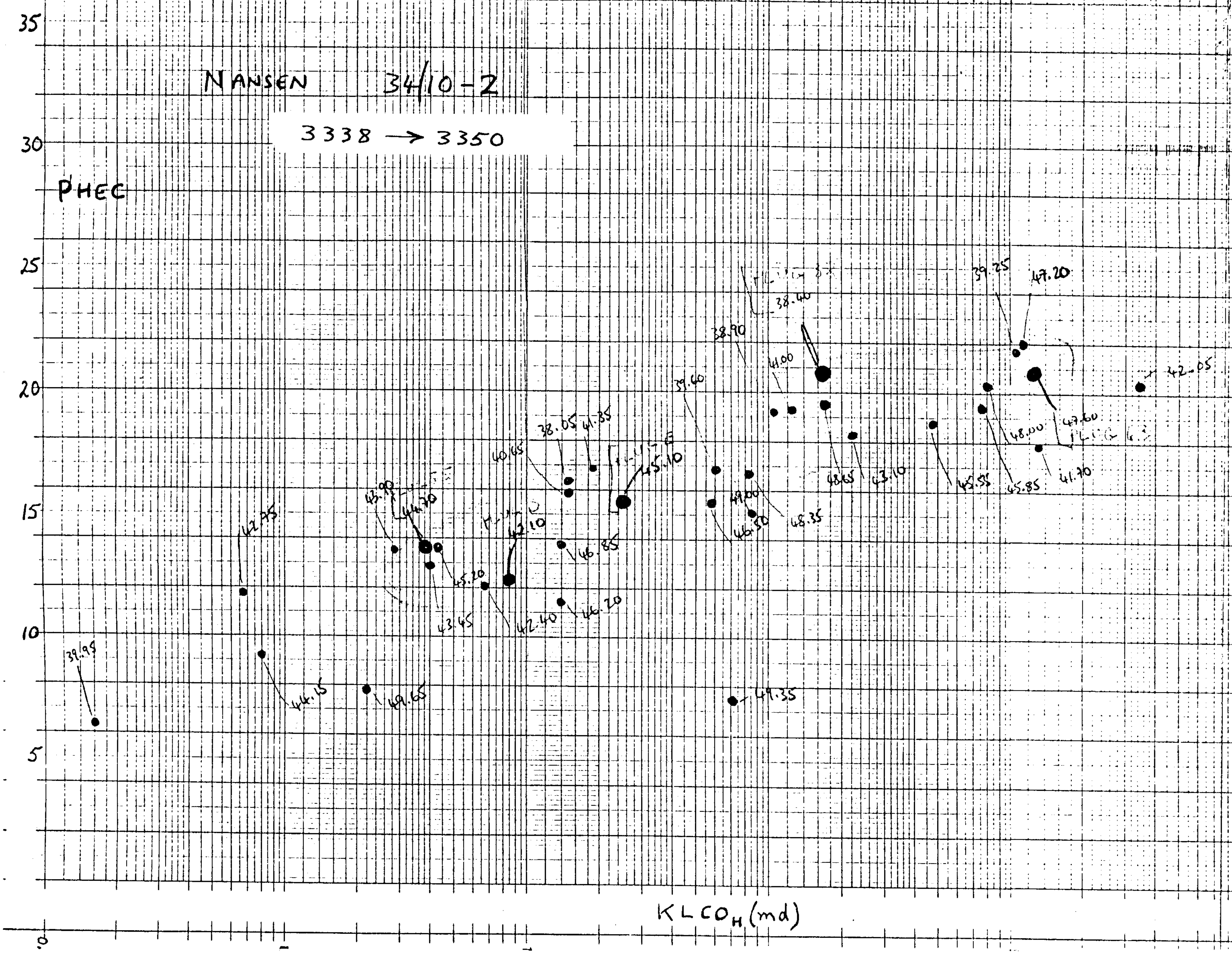


FIG 3

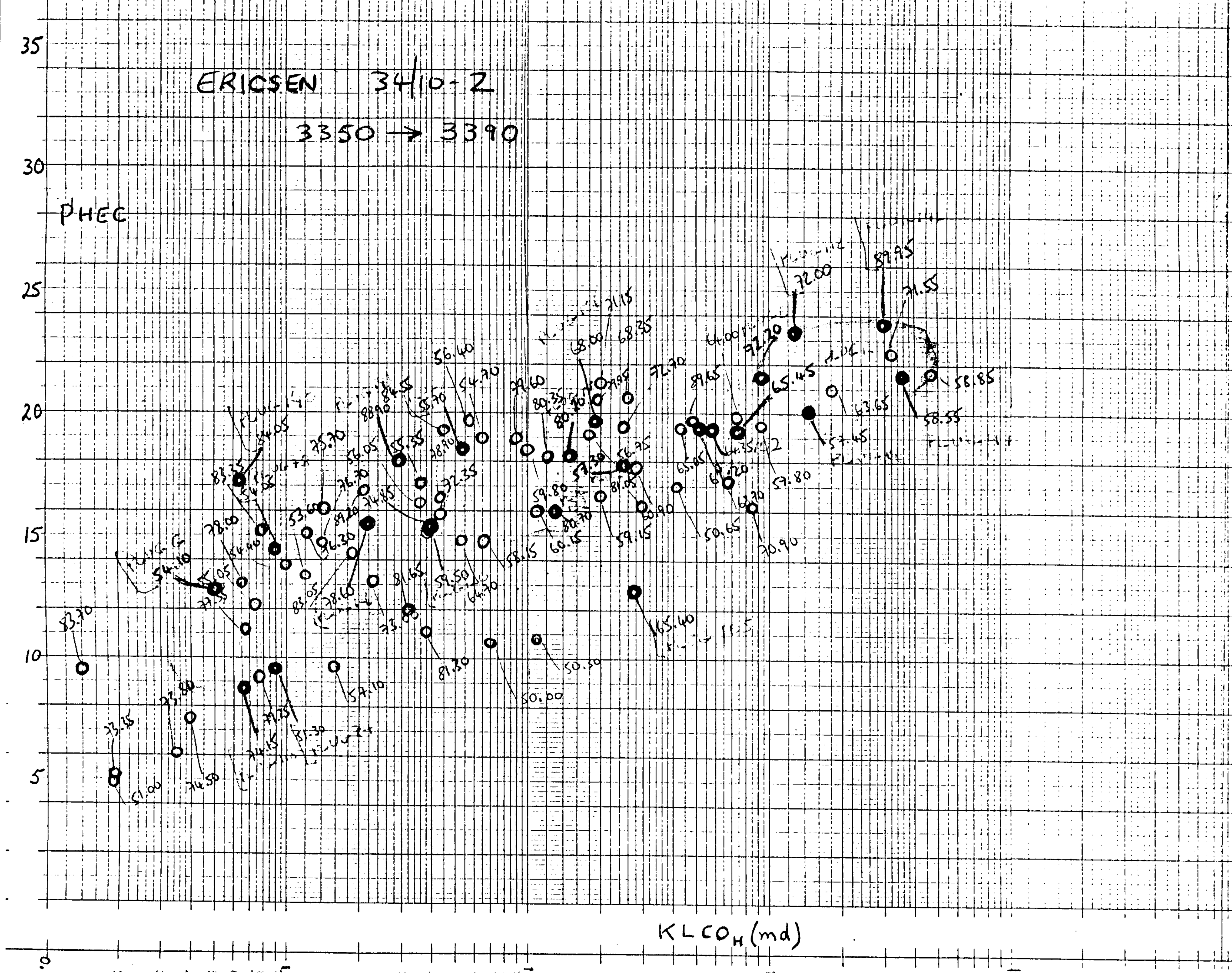
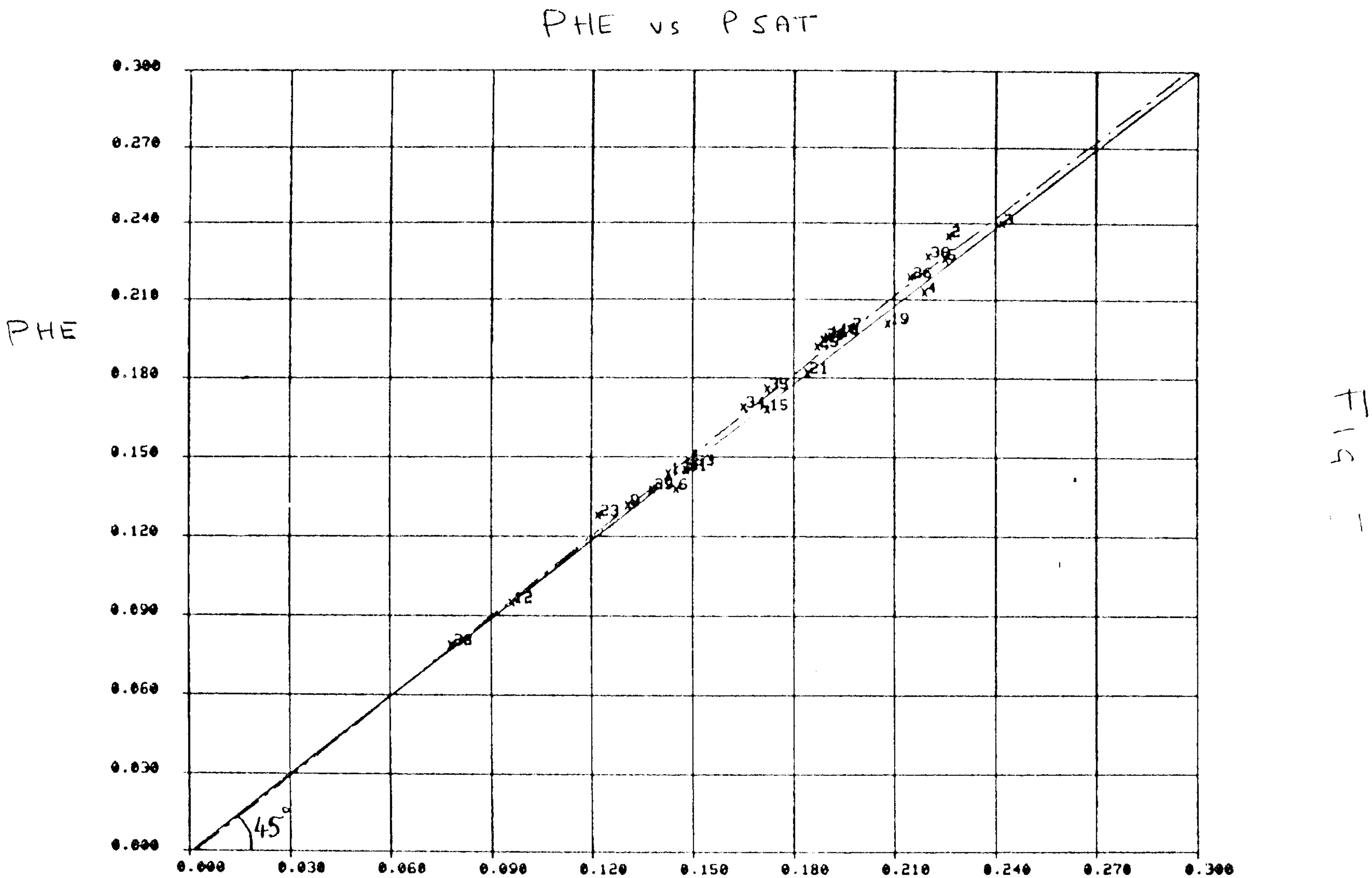


FIG 4

PHE vs PSAT



PHE VS PSAT

Y=A*X+B

A= 1.01489116 B= -0.00157961 C2= 0.98946763

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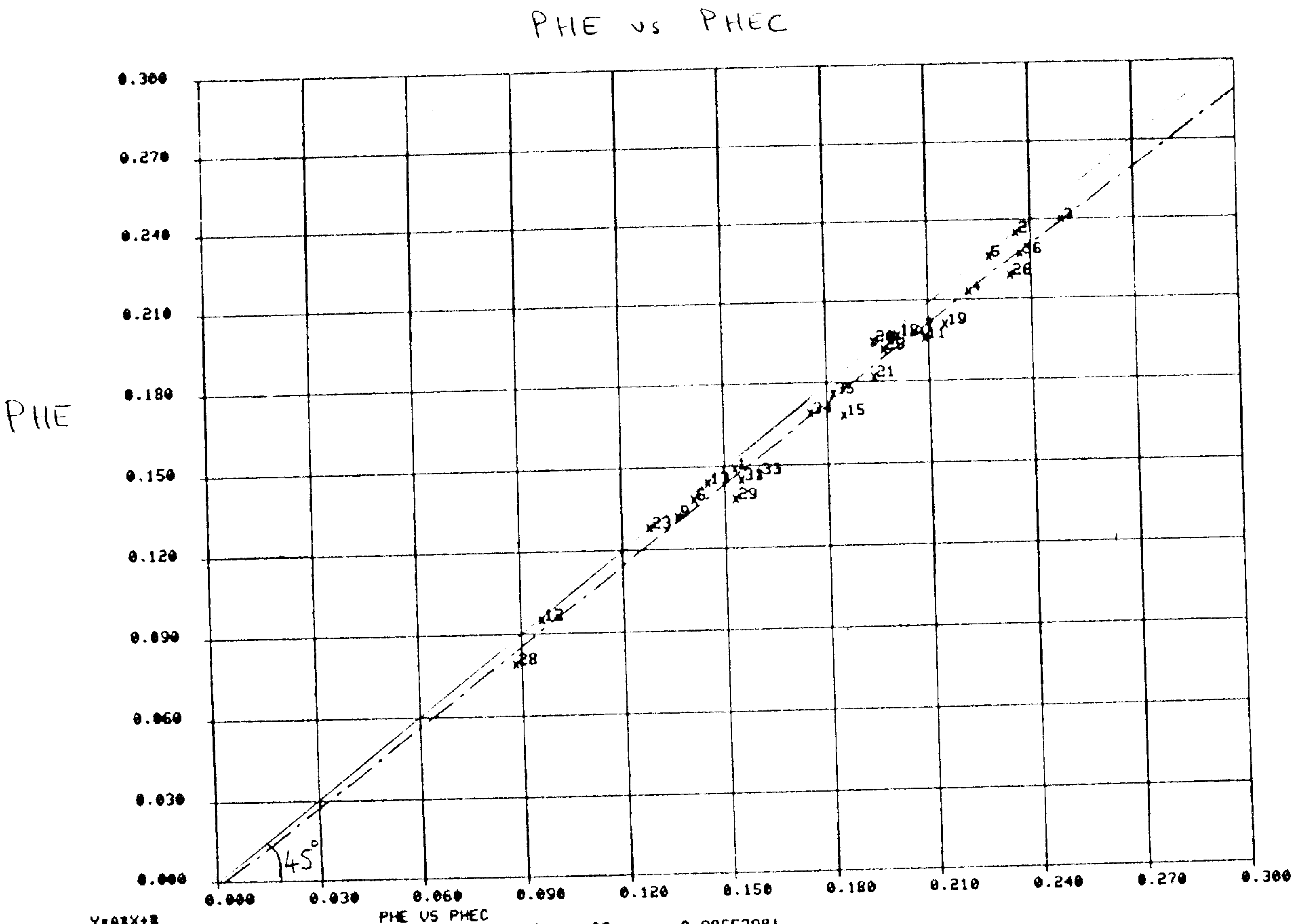
NO
DO YOU WANT TO ADD ANY POINTS?
NO

P L O T T E D B Y : DT



Y=A*X+B
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DO YOU WANT TO DELETE ANY POINTS?
NO
DO YOU WANT TO ADD ANY POINTS?
NO

P L O T T E D B Y : DT

FIG.

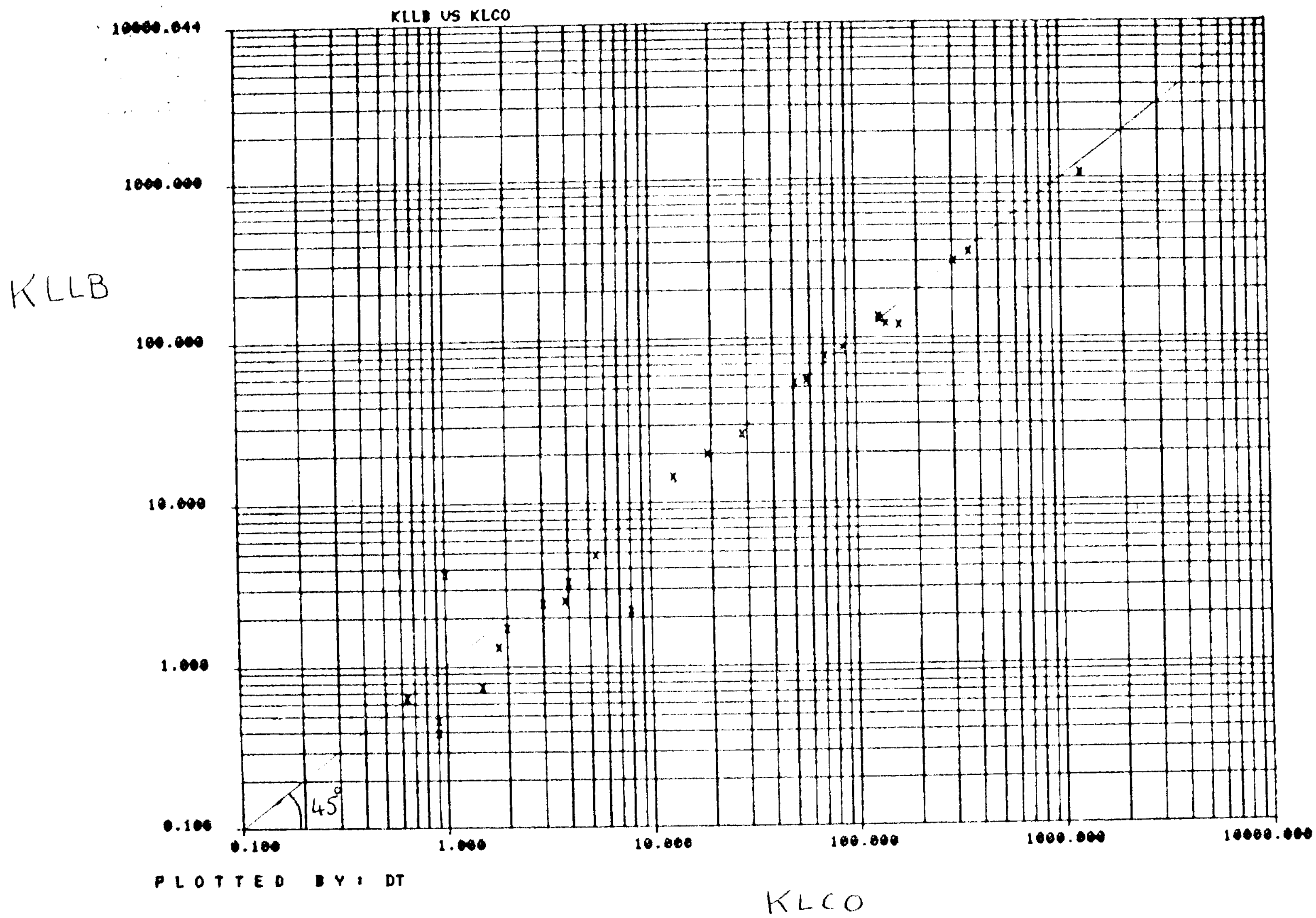

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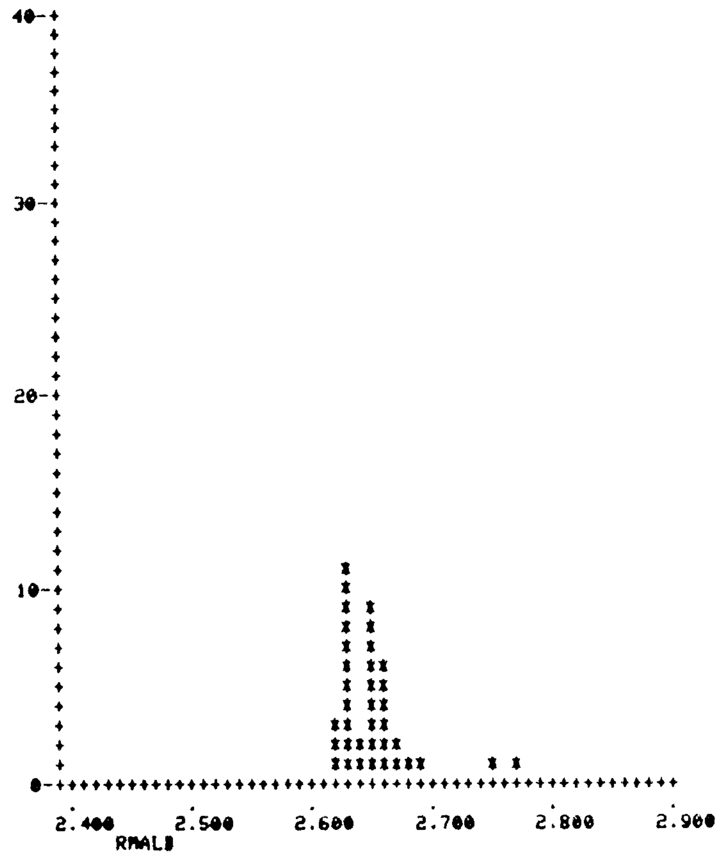
Fig 4

RMALB HISTOGRAM



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RMAC HISTOGRAM

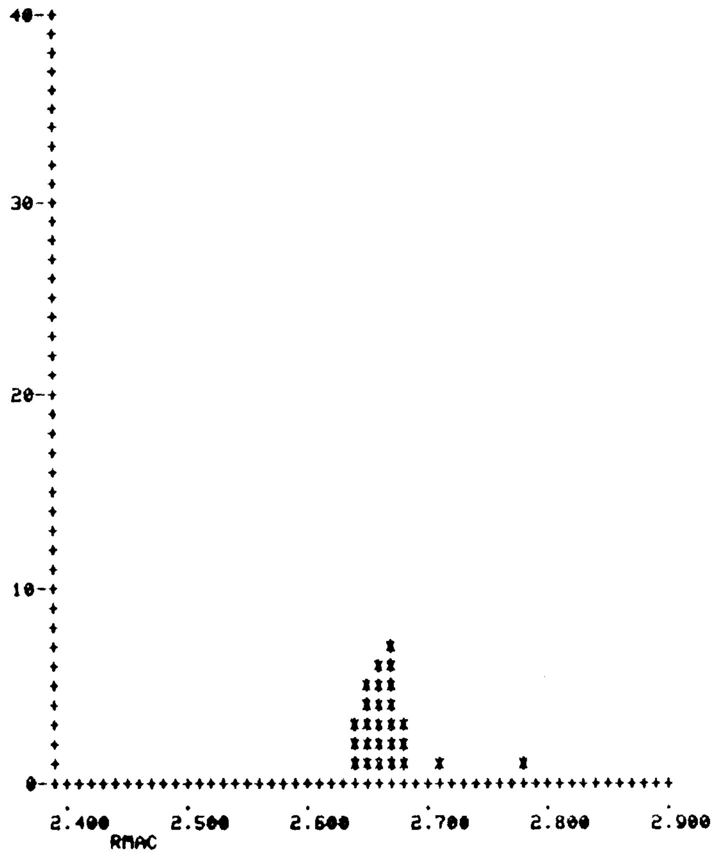

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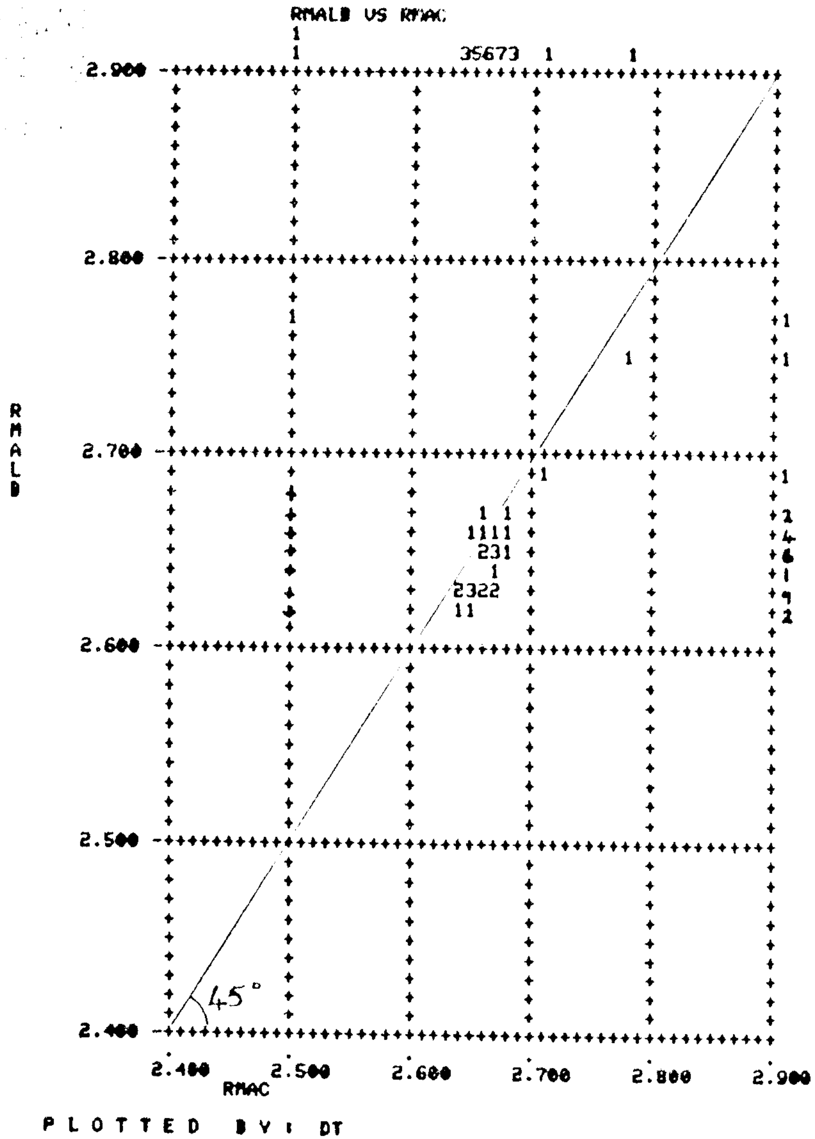
Fig


RMALB VS RMAC
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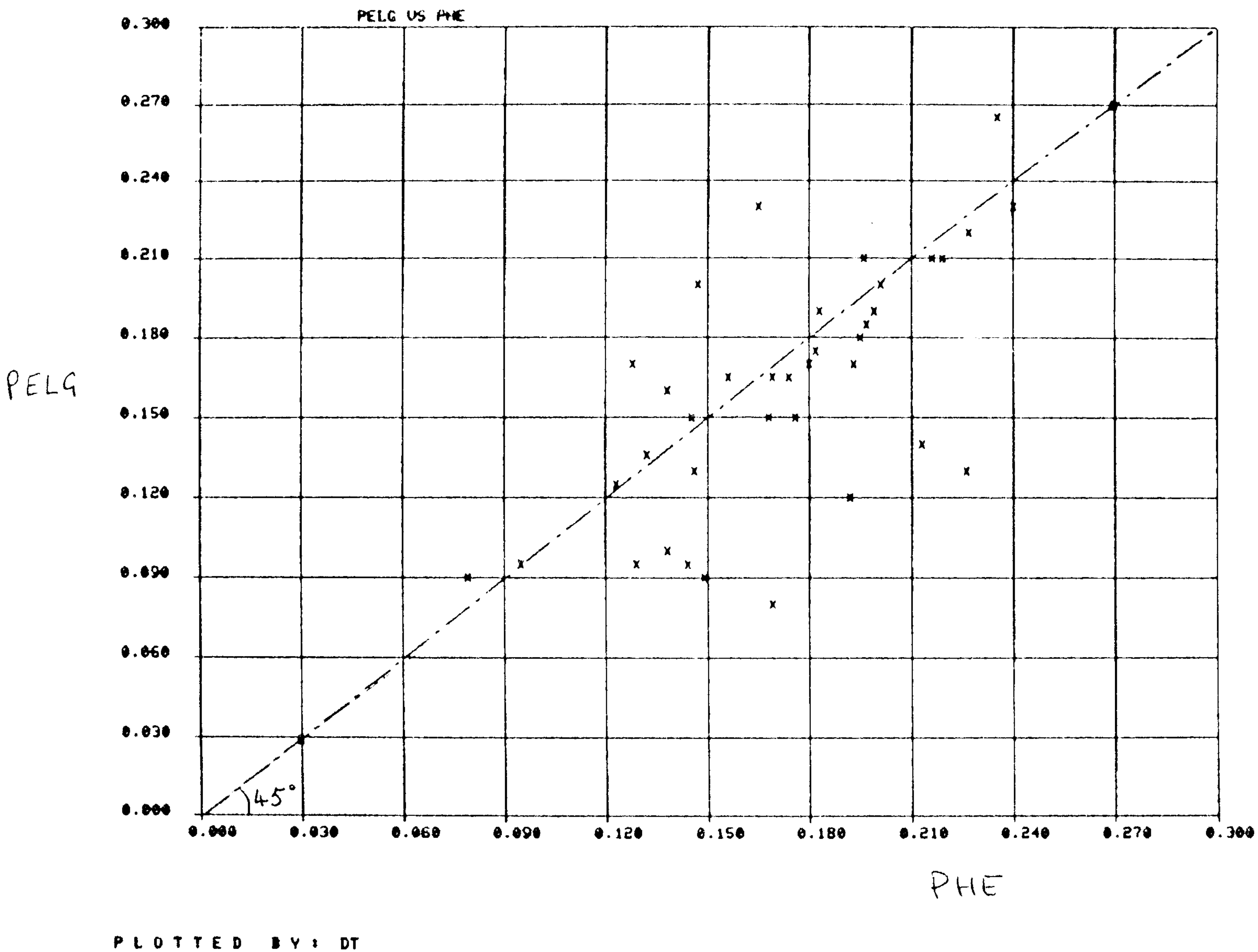
2.800
2.700
2.600
2.500
2.400
R
M
A
L
B
2.400
2.500
2.600
2.700
2.800
2.900
RMAC
45°
PLOTTED BY: DT

FIG


PELG VS PHE
PELG
PHE
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0.030
0.060
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0.150
0.180
0.210
0.240
0.270
0.300
45°
PLOTTED BY: DT

FIG 1

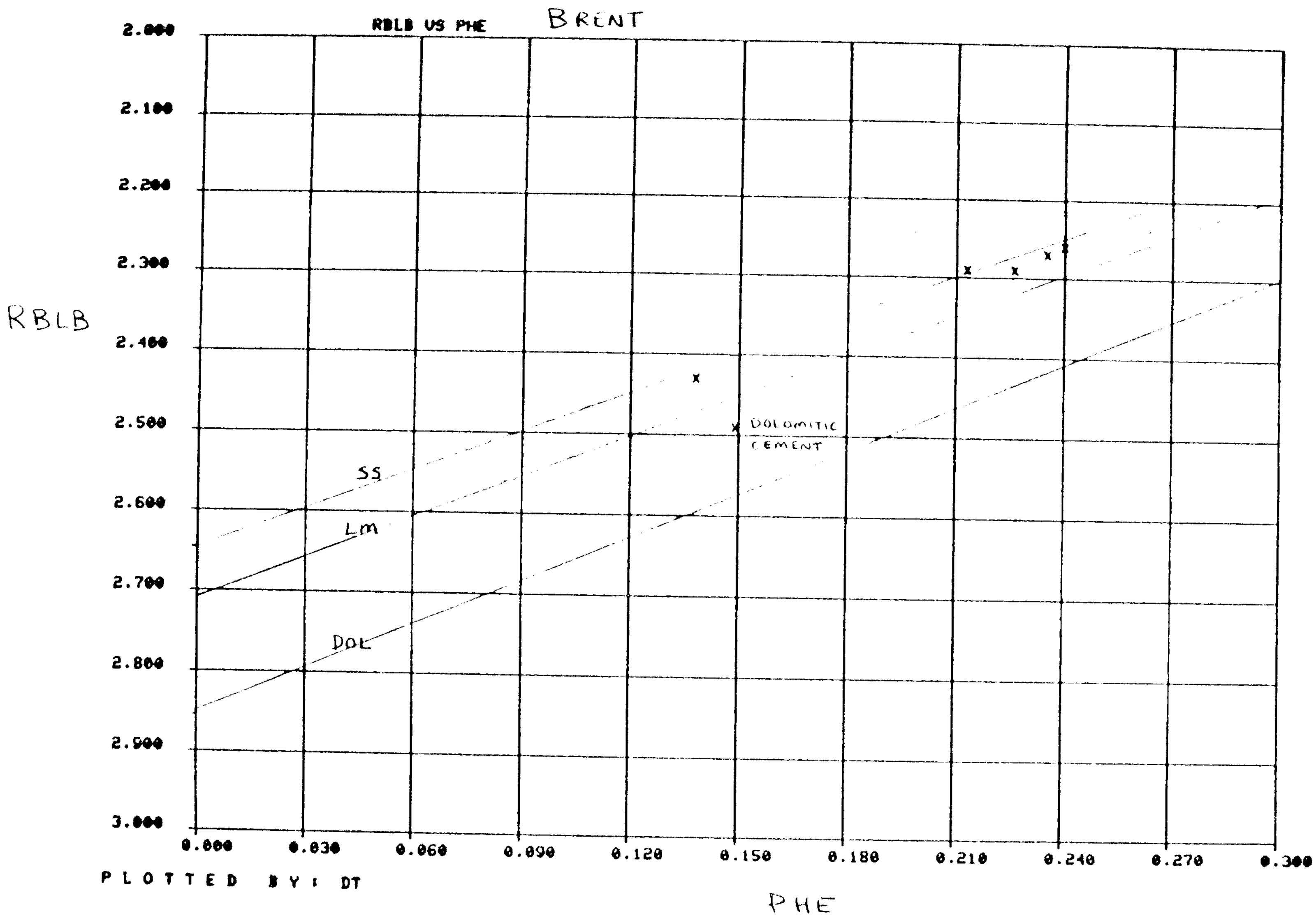
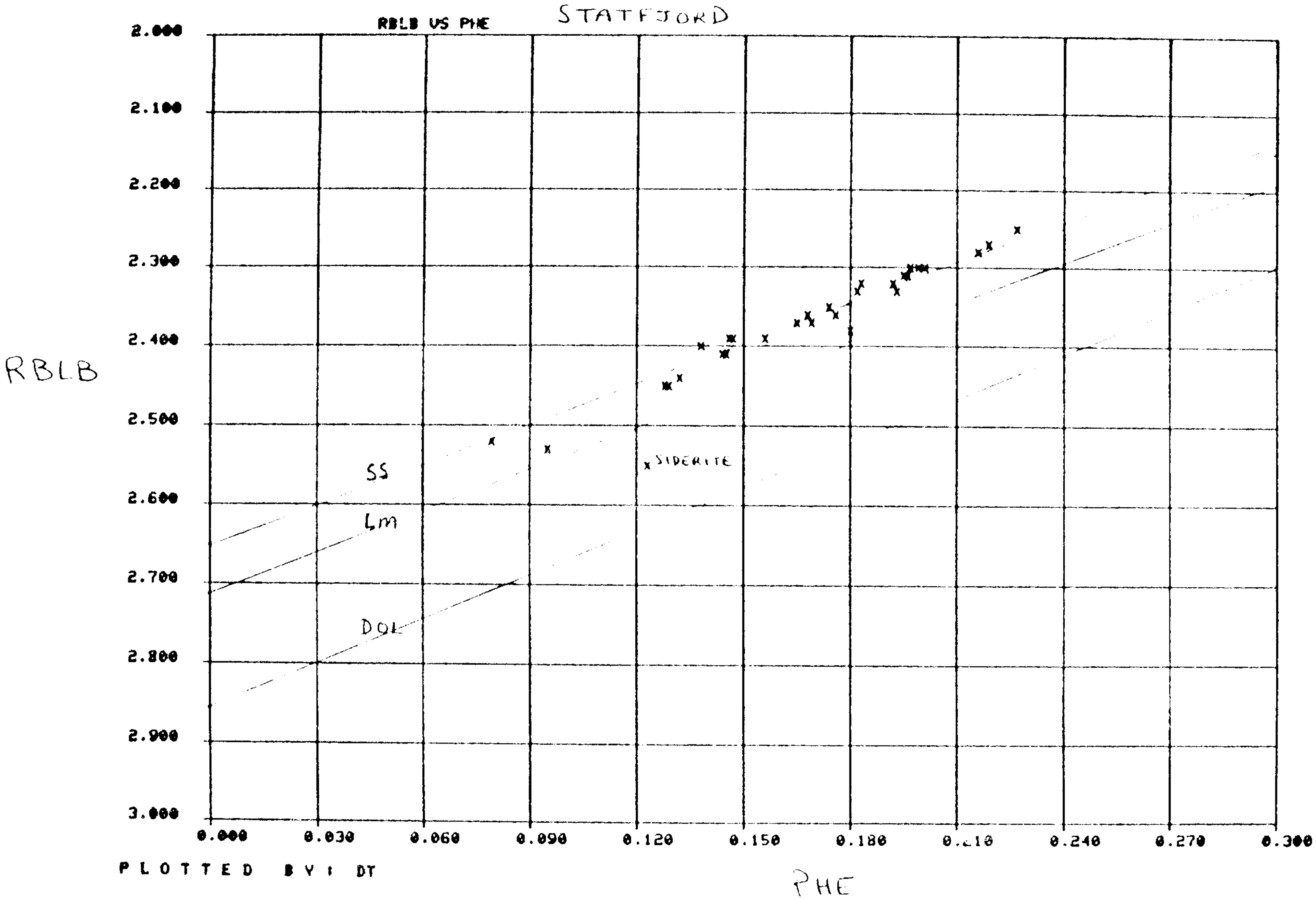
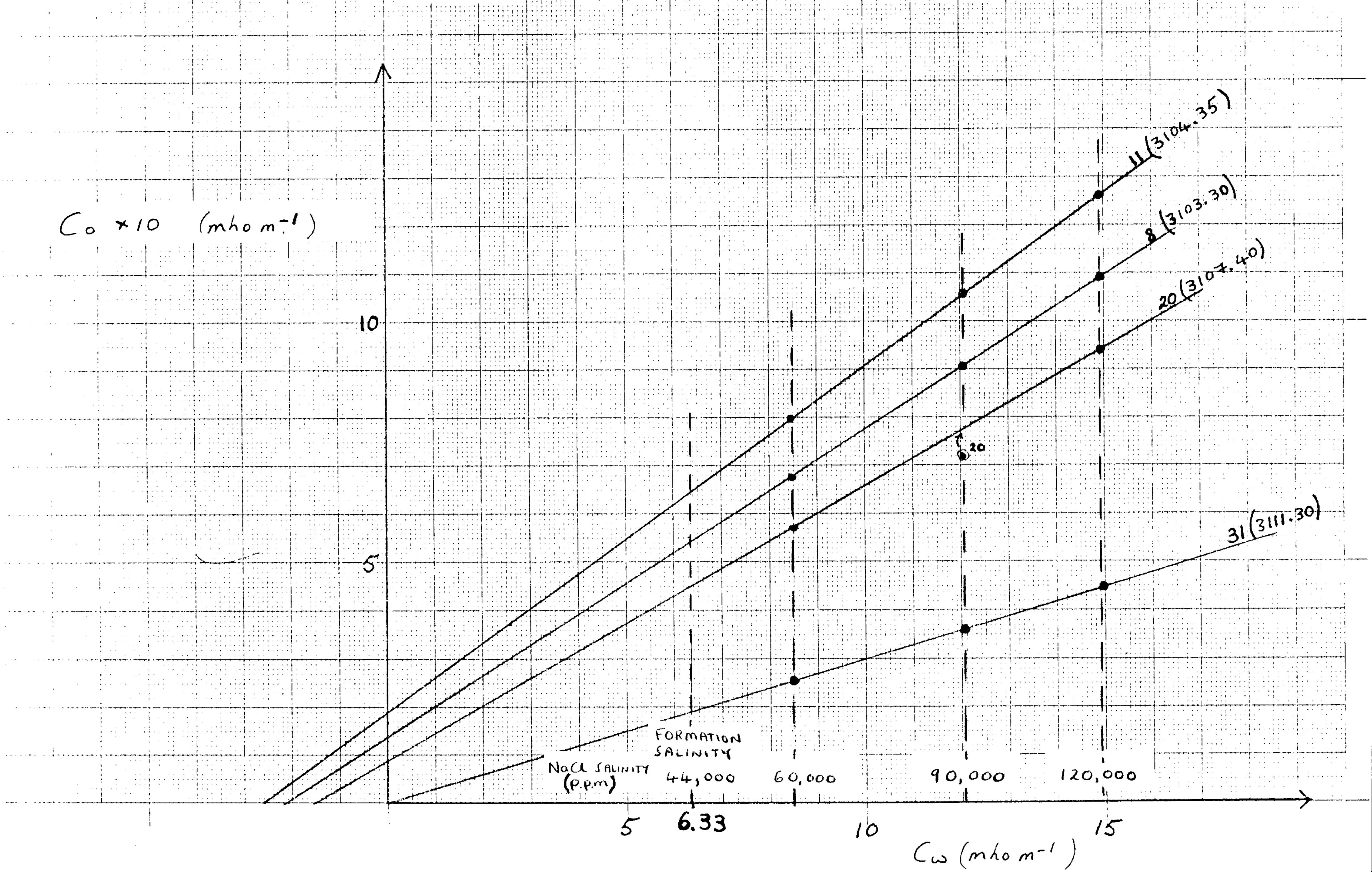

RBLB VS PHE
BRENT
RBLB
PHE
2.000
2.100
2.200
2.300
2.400
2.500
2.600
2.700
2.800
2.900
3.000
0.000
0.030
0.060
0.090
0.120
0.150
0.180
0.210
0.240
0.270
0.300
SS
Lm
DOL
DOLOMITIC CEMENT
PLOTTED BY: DT

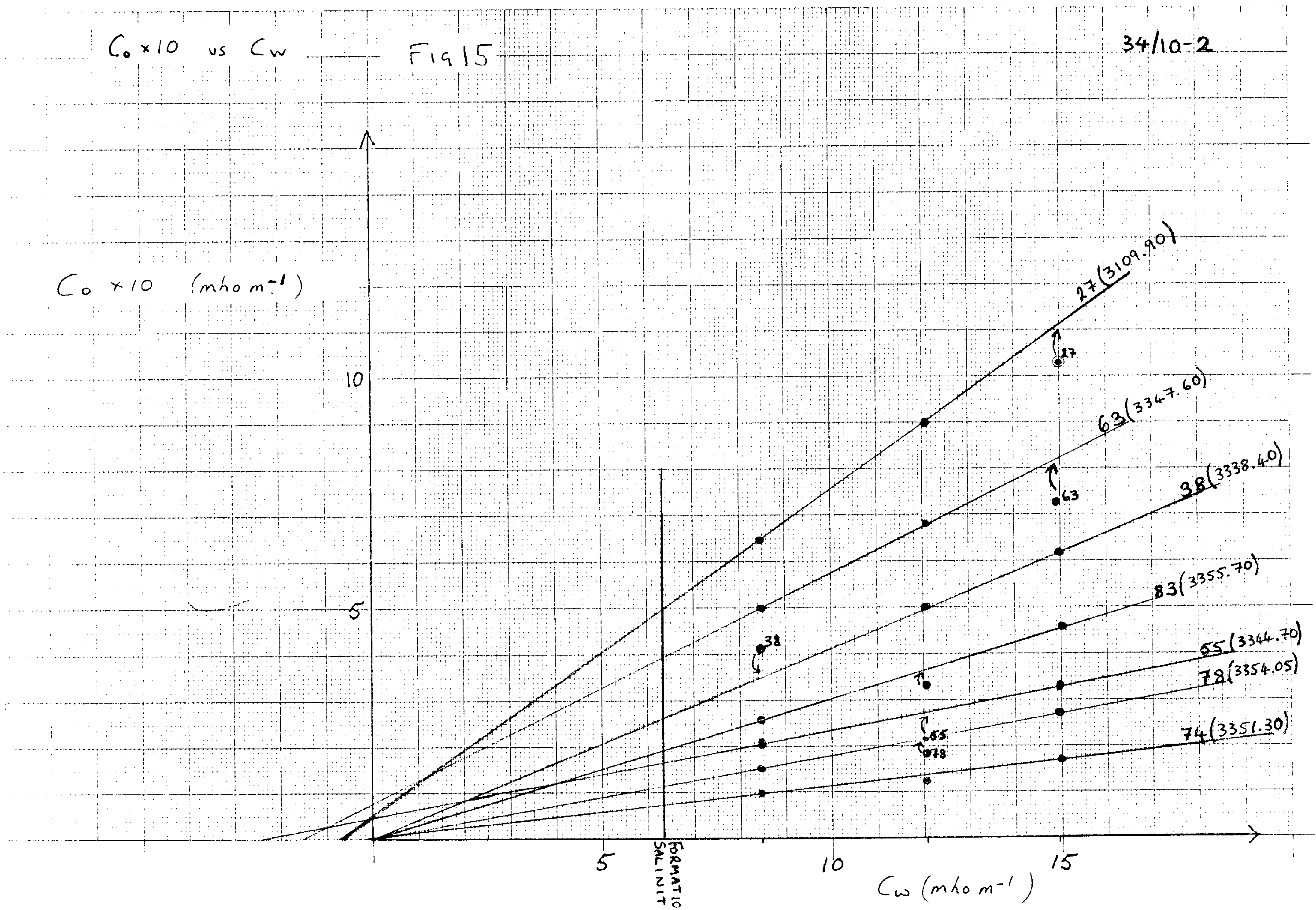
FIG 1



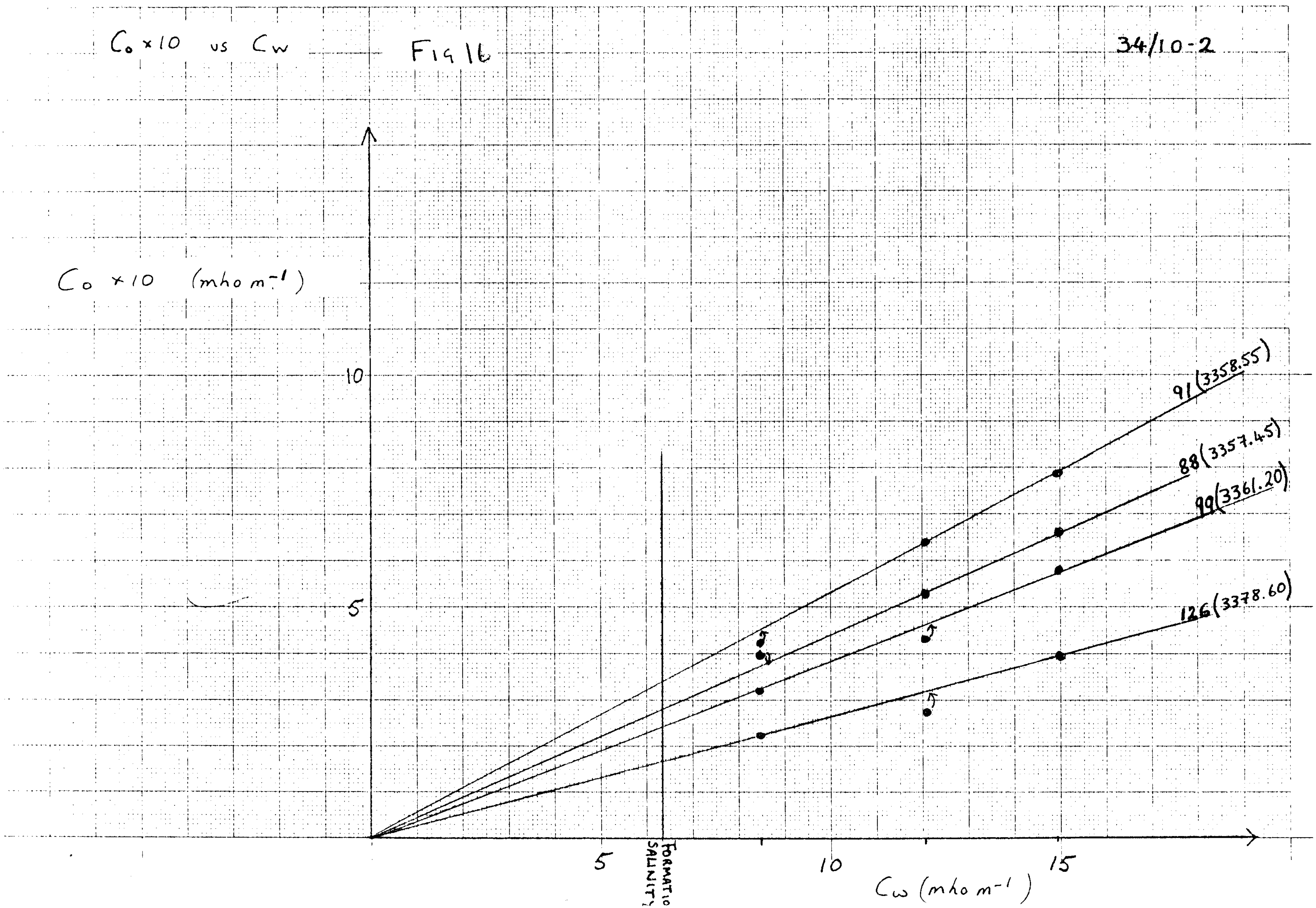
RBLB VS PHE
STATFJORD
2.000
2.100
2.200
2.300
2.400
2.500
2.600
2.700
2.800
2.900
3.000
RBLB
SS
Lm
DOL
SIDERITE
0.000
0.030
0.060
0.090
0.120
0.150
0.180
0.210
0.240
0.270
0.300
PLOTTED BY: DT
PHE

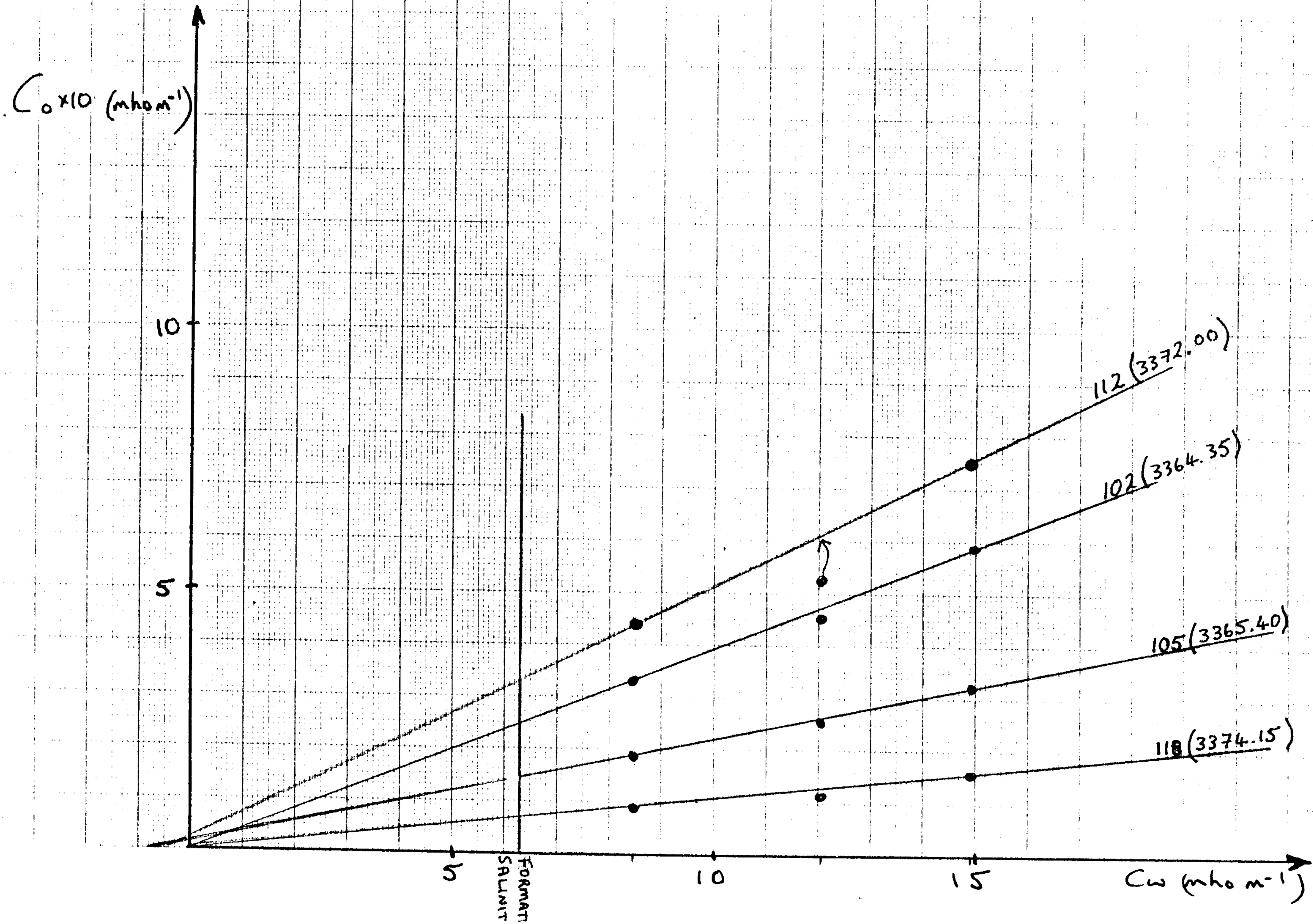
$C_o \times 10$ vs C_w Fig 4 34/10-2

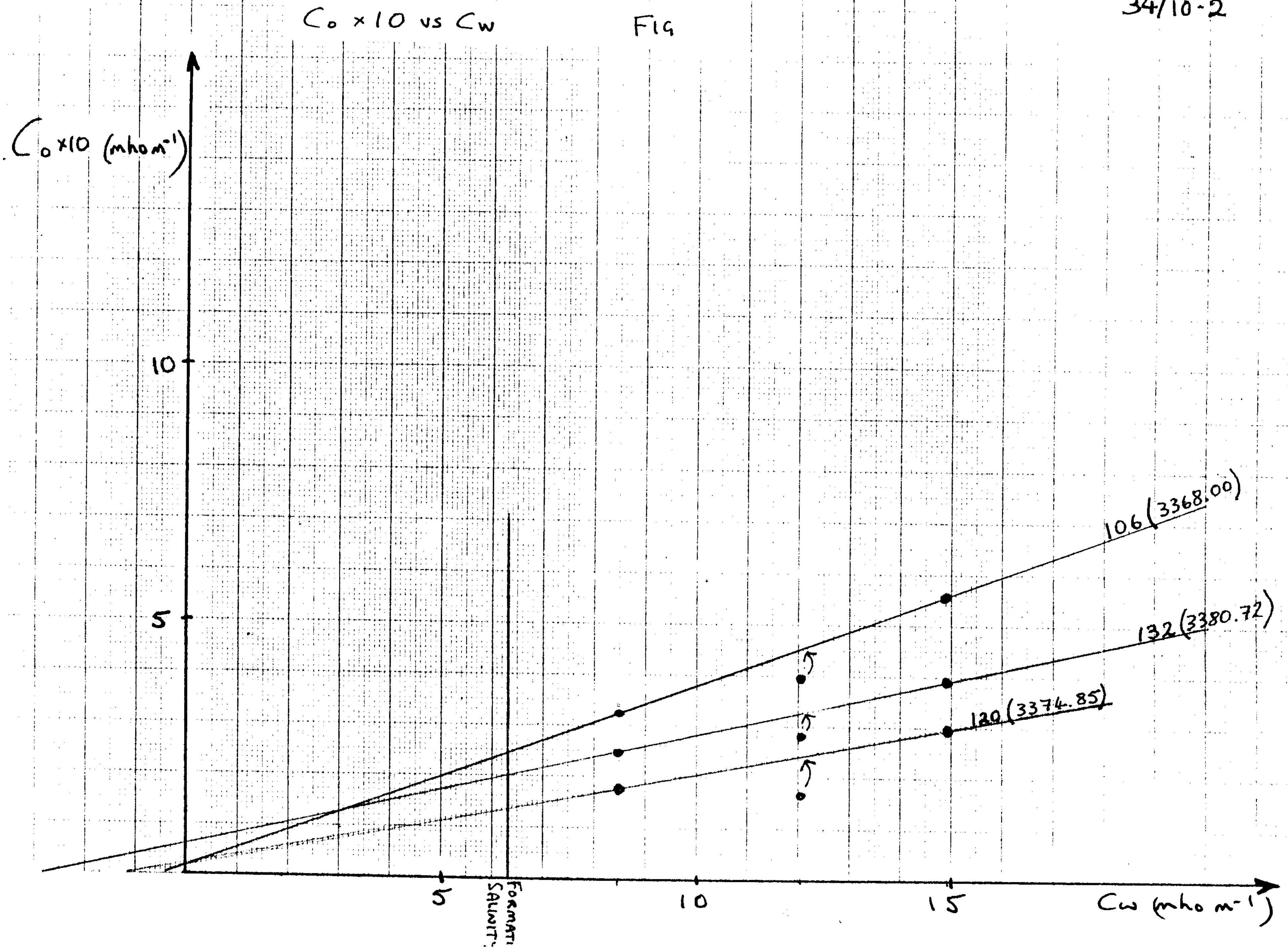


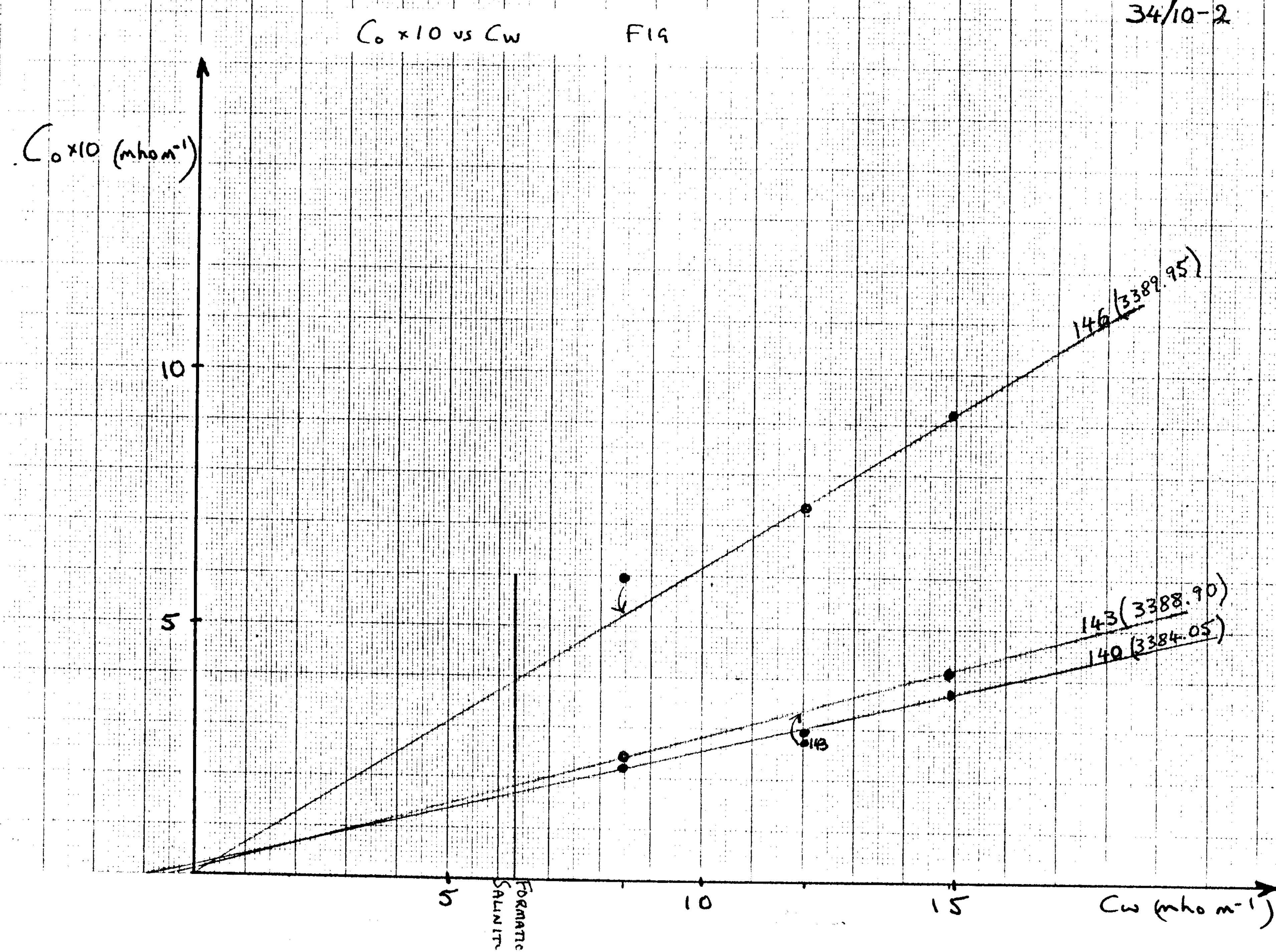


Co x10 vs Cw
Fig 15
34/10-2
Co x10 (mho m-1)
10
5
5
10
15
FORMATION SALINITY
Cw (mho m-1)
27 (3109.90)
63 (3347.60)
38 (3338.40)
83 (3355.70)
55 (3344.70)
78 (3354.05)
74 (3351.30)
27
63
38
55
78


Co x10 vs Cw
Fig 16
34/10-2
Co x10 (mho m-1)
10
5
5
10
15
FORMATION SALINITY
Cw (mho m-1)
91 (3358.55)
88 (3357.45)
99 (3361.20)
126 (3378.60)


$C_o \times 10$ vs C_w
FIG
$C_o \times 10$ (mho m^{-1})
10
5
5
10
15
FORMATION SALINITY
C_w (mho m^{-1})
112 (3372.00)
102 (3364.35)
105 (3365.40)
118 (3374.15)


Co x 10 vs Cw
FIG
Co x10 (mho m-1)
10
5
5
10
15
Cw (mho m-1)
FORMATI
SALINITY
106 (3368.00)
132 (3380.72)
120 (3374.85)


$C_o \times 10$ vs C_w FIG
$C_o \times 10$ (mho m^{-1})
10
5
5
10
15
C_w (mho m^{-1})
FORMATIO SALINITY
146 (3389.95)
143 (3388.90)
140 (3384.05)
143

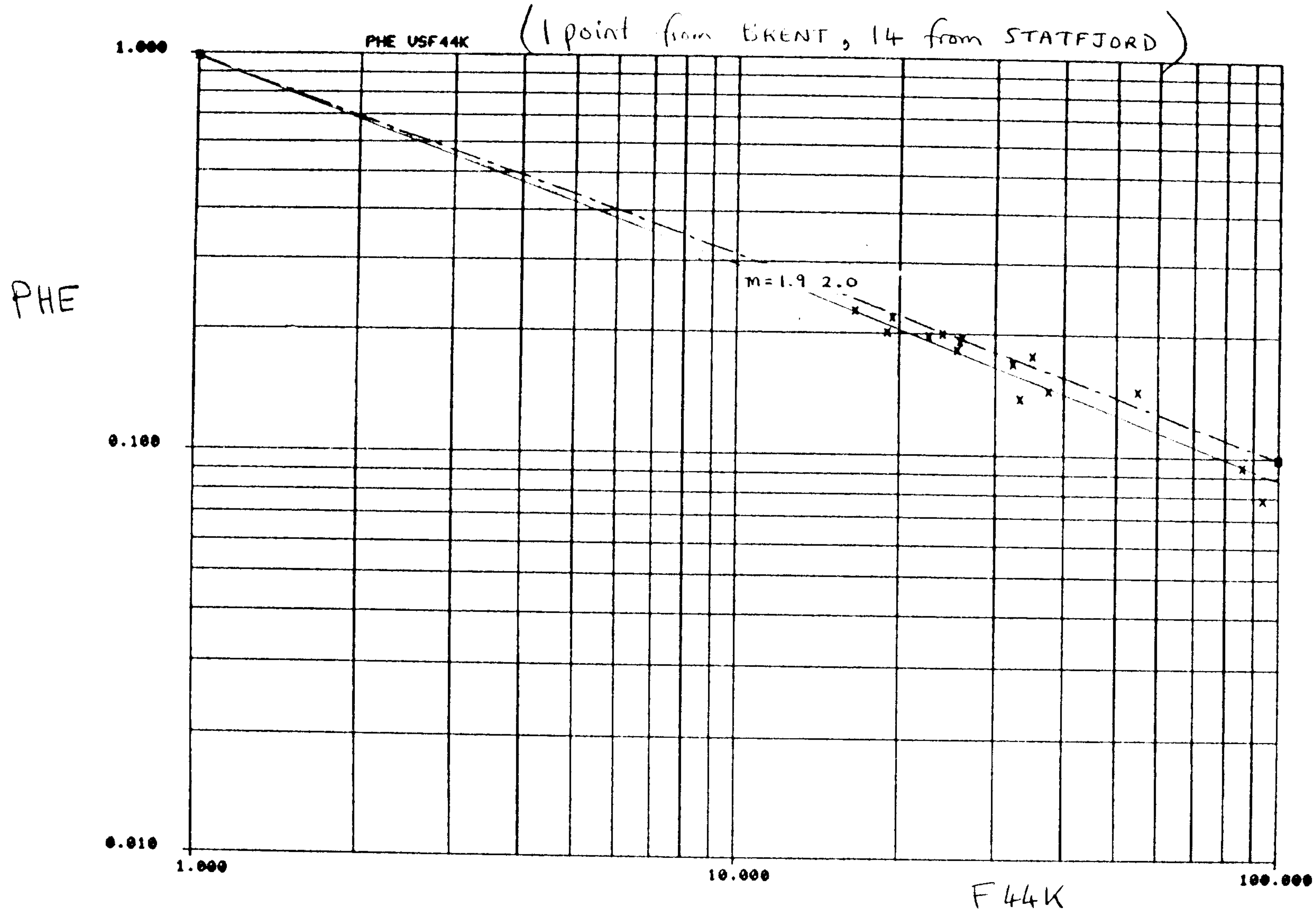


Fig 2c

PLOTTED BY: DT

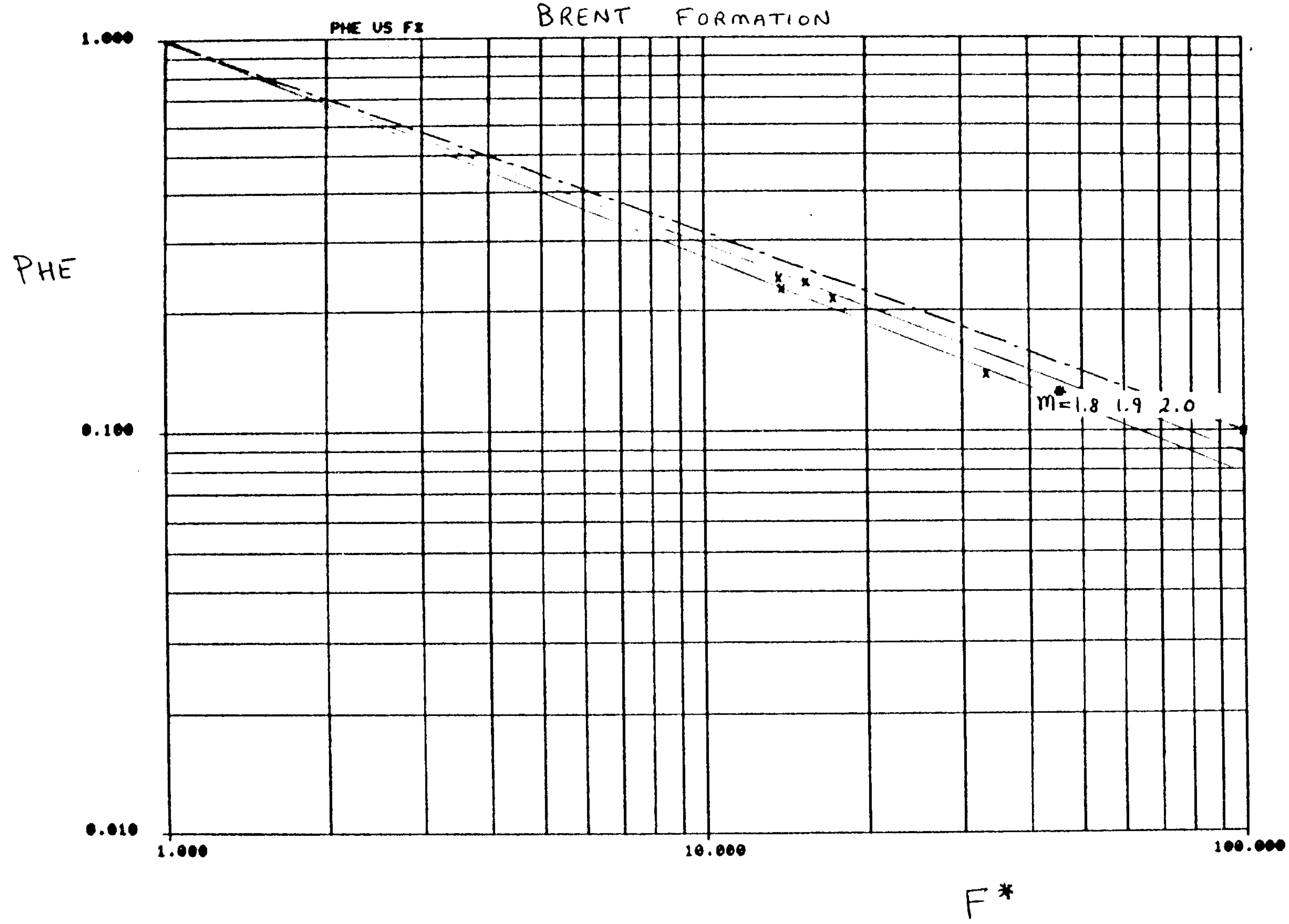


Fig 21

PLOTTED BY: DT

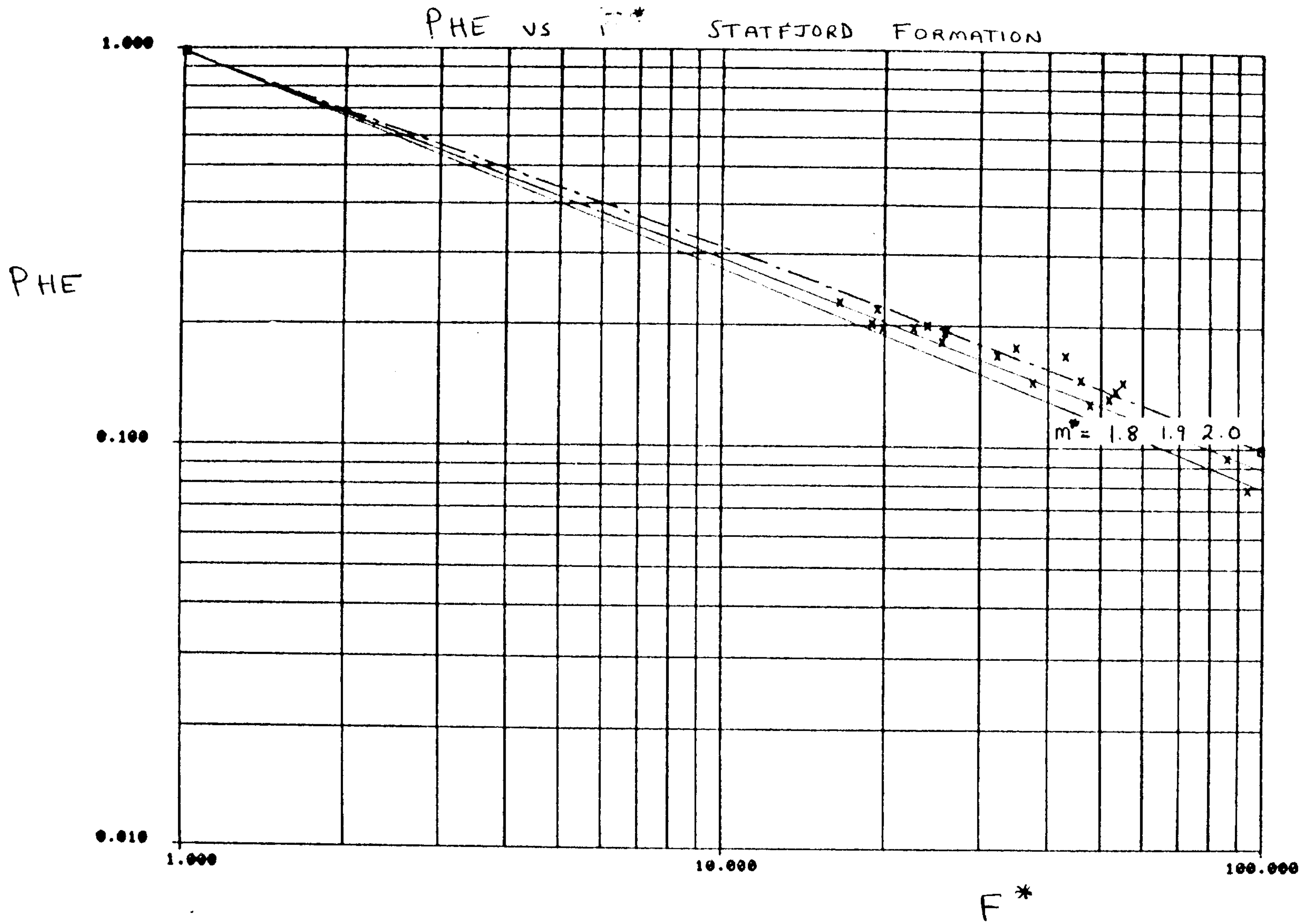


FIG 2

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