SPE 49556

Rock Type and Permeability Prediction from Mercury Injection Data: Application to a Heterogeneous Carbonate Oil Reservoir, Offshore Abu Dhabi (United Arab Emirates)

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Abstract

Present study highlights reservoir engineering contribution to a reservoir characterization study.

Subject reservoir is a heterogeneous limestone and dolomite carbonate reservoir, with a huge gas cap, producing under peripheral water injection.

Available conventional and SCAL data were screened, filtered and introduced in spreadsheets.

Measured permeability and porosity values were corrected to reservoir conditions in order to bring all relevant data to the same conditions.

The main objective of analyzing Mercury Injection Capillary Pressure (MICP) data was to come up with conceptual reservoir flow-model from integrating the rock fabrics of the depositional facies with the MICP measurements.

Distinguishing dolomite from limestone plugs was the first step taken in the rock typing exercise based on petrography findings. MICP curves were sorted based on various criteria to come up with 16 rock types using Excel 7.0 spreadsheets equipped with macro facility to speed up analysis. Water saturation versus pore throat distribution and R35 (Inverse of capillary pressure at 35% mercury saturation) parameters were found to be the most useful tools in this exercise.

Second campaign of mercury injection data (99 samples) was carried out in order to capture more samples in low populated rocks. This brings total mercury injection samples to 568 taken from 15 wells, in which around 50% were dolomite.

The 16-rock-model has been successfully correlated to distinctive flow units (such as FZI: Flow Zone Index and RQI: Reservoir Quality Index) and in light of the results it was possible to upscale the 16-rock-type model into 9-rock-type model. The 9 rock types consist of 4 dolomite rock types and 5 limestone rock types.

A stochastic model has been developed and applied successfully on cored wells, using Random Number Generator function in Excel 7.0, to predict rock number (type) at a given porosity and permeability for every foot.

Capillary pressure end points were used to predict water saturation and comparison against water saturations from logs revealed a good relationship.

Permeability and Porosity under Stress

To correct measured permeability from ambient conditions to reservoir conditions, experimental data from 7 wells has been utilized (Figure-1). Two trends can be distinguished (Figure-1), the first at permeability values less than 1 md (Figure-1, A) and the second trend at permeability values greater than 1 md (Figure-1, B). Results shown in Figure-1, C suggested a reduction of around 14% to be applied for ambient permeability values larger than 1md. Porosity data was corrected to reservoir conditions, from under stress experiment conducted on 7 wells and results are shown in Figure-2. Reduction factor profile has been generated to convert ambient porosity values to reservoir conditions as shown in Figure-2. A reduction factor of around 3% has been used to convert ambient porosity measurements to reservoir conditions.

Screening of Data

Initially, 469 plug samples from 12 wells were used for MICP experiments covering all horizons in the reservoir. The study completed describing 11,300 thin sections and findings were integrated with engineering analysis results of MICP data.

A second campaign of MICP experiments (an additional 99 samples from 3 new wells) was launched to capture more samples in the low populated rock types. This brought the total mercury injection samples to 568 from 15 key wells.

A 62% out of the total samples (i.e 352) were found usable for analysis. Criteria for rejecting samples were mainly attributed to tightness of samples and / or presence of induced fractures.

Grouping into Dolomite and Limestone

Mercury injection samples were grouped into dolomite and limestone based on lithology information. Distinctive behavior was noticed for dolomite compared to limestone samples as demonstrated in Figure-3. A 60% cutoff has been introduced to define the type of lithology. This was based on sensitivity analysis of MCIP data. Anhydrite rocks were given the number " 0 " and defined as equal or exceeding 60% anhydrite content. Dolomite rock is defined as 60% or more of dolomite content and limestone rock is defined as 60% or more of calcite content. Dolomite rock numbers were assigned odd integers while even integers were used to label limestone rocks in the number that follows.

Approach for Sorting MICP Results and Creation of Rock Predictive Models

Water saturation versus pore throat size and the R35 parameter (R35 is the inverse of Pc at 35% mercury saturation) were found to the most useful tools for rock typing. Pittman[1] reported a technique of correlating R35 with porosity and permeability, which was adopted in this study. Results of this approach are shown in Figures 4, 5 and 13.

A linear correlation of R35 with porosity and permeability, presented an R^2 coefficient of 0.92 (Figures 5&13). This finding was later adopted as the basis for the rock type prediction. Also this correlation helped to define the boundary conditions prior to executing the generated stochastic model.

Figures 4 & 5 summarize the approach used in rock typing in which MICP data was sorted using Excel 7.0 spread-sheets equipped with a macro facility to speed up the analysis. Sorting of MICP data, which is summarized in Figures 4 & 5, used mainly four parameters as criteria :

1) Magnitude of effective pore throat size obtained from pore throat distribution functions, 2) Water saturation versus pore throat size variations , 3) Capillary pressure curves[2,3] and 4) Trend of permeability versus porosity .

The generated rock types then were validated for flow unit grouping using FZI (Flow Zonal Index) and RQI (Reservoir Quality Index) tools. Results[4] were encouraging and are displayed in Figures 4, 5 and 12.

Figure-5, shows the details and steps of the in-house stochastic model which is based on the randomness concept[5] .

The Detailed Model: 16-Rock Model

Figures-6, 7 & 8 show three properties derived from the MICP experiments: water saturation versus pore throat size (Figure-6), pore throat distribution function versus pore throat size (Figure-7) and lab capillary pressure versus water saturation (Figure-8). Eight rock numbers (the odd integer numbers) were assigned to dolomites and the other eight rock numbers (even integer numbers) were assigned to limestone plug samples.

For each rock number a permeability versus porosity relationship is generated and displayed in Figures-9A & 9B. Also the variation of irreducible water saturation with porosity is shown for each rock type in the same Figures (9A & 9B). The main characteristics of the 16-Rock model are shown in Figures 11A and 11B.

Permeability decreases from rocks 1 and 2 (the best reservoir rocks) to rocks 11 and 12 with gentle declining trend, while a second and steeper permeability decline trend has been identified for rocks 13 to 16 (Figure-11A). Similar observations were identified for FZI, initial water saturation and pore throat size (Figure-11A). Two good correlation trends were established between pore throat size and permeability for dolomite and limestone rock types (Figure-5).

The Up-Scaled Model: 9-Rock Model

From the encouraging results obtained from correlating the various rock types to unique flow unit patterns and from permeability versus porosity trends (Figures 9A, 9B & 11A) it was possible to correlate these findings with the geological criteria, which was established from the thin section analysis (Figure-12). The 16-rock model has been up-scaled to 9-rock model in which rocks 1, 3, 5 and 7 have been assigned to dolomite while rocks 2, 4, 6, 8 and 9 represented limestone[4] (Figures 10, 12, 13 & 13 A). Figure-12 summarize the geological findings for each of the nine rock types, which was demonstrated by the distinctive flow unit regions when plotting RQI vs. normalized porosity.

Rock Type Prediction Models

Four models were created to predict rock types :

a) Stochastic 16-rock type model to predict rock number from R35 vs. rock number (Figure-14): Prediction accuracy tolerance for this model was tested and estimated in the domain of 70% to 80%.
b) Stochastic 9-rock type model to predict rock number from R35 vs. rock number (Figure-14): Prediction accuracy for this model was estimated in the range from 60% to 70%.
c) Deterministic model based on RQI vs. normalized porosity (Figure-12): Due to the clear boundaries found between each rock type, this gave the best results. Accuracy to predict rock numbers was as high as **97%.**
d) Stochastic model to predict permeability from core data: The stochastic approach led to accurate predictions of permeability.

Accuracy was **90%** for permeability values above 0.5 md.

The four models were tested on three cored wells and results, on well-XX is displayed in Figure-14.

Conversion of MICP to Reservoir Conditions

Assumptions used to calculate capillary pressure at reservoir conditions and height above free water level are tabulated in Scheme-1. Results are displayed in Figure-13A.

The contact angle between oil and brine has been taken as 50 degrees[6] since objective reservoir is classified as intermediate to water wet.

Surface tension between oil and brine was measured from a representative oil sample and found to 36 dynes/cm, which was used in present study.

Careful selection of parameters required for conversion to reservoir conditions resulted in a good match between Sw produced by logs and Sw calculated from MICP as will be shown later.

Relationship between MICP and Porosity

Figure-13B has been created to demonstrate the relationship between porosity and the various capillary pressure curves for each rock. From the established relationship in Figure-13B a correlation has been generated between initial water saturation and porosity for each of the nine rocks(Figure-15). Initial water saturation (Swi) has been considered at the highest capillary pressure used in the MICP experiments (2000 psia).

J-Functions

Benefits of using J-functions were minimal since MICP data was correlated with porosity trends.

Validation of MICP Curves

Conventional core and log data from three key wells were loaded on a single spreadsheet and for each foot the rock number and Swi (from Figure-15 correlations) was estimated. For each rock (number) type a multi linear equation to calculate log Sw was established correlating Swi, porosity and height above free water level. This step was vital to cross check our MICP curves to log data.

Prediction of Water Saturation

The encouraging results made us progress one step further to try and predict Sw from logs using the correlations established in Figure-16. Results for two wells are exhibited in Figure-17.

Water saturation prediction adopted a treatment similar to the documented[7] method which was conducted on a sandstone reservoir.

Conclusions

a) Careful filtering, refining and correction of raw data are a key element.
b) R35 has been found to be a very useful tool to accurately predict permeability and rock type.
c) Conversion of MCIP rock types into flow unit categories was a key step to successful up-scaling of the 16-rock type model to 9-rock type model.

d) Dolomites are grouped to 3 main reservoir rocks : **1** (the best rock), **3** (good) and **5** (fair). Rock **7** is considered a non-reservoir rock.
e) Limestone rocks are grouped into **4** main reservoir rocks : **2** (the best rock), **4**(good), **6**(fair) and **8** (marginal). Rock **9** is considered a non-reservoir rock.
f) The best model to predict rock type is a deterministic model based on classifying flow units(RQI vs. Normalized porosity).

References

1) Edward Pittman, "***Relationship of porosity and permeability to various parameters derived from mercury injection-capillary pressure curves for sandstone***". The American Assoc. of Petroleum Geologists Bulletin, Vol. 76, No. 2 Feb. 1992.
2) David C. Kepaska-Merkel, "***Capillary-Pressure characteristics of smack-over reservoirs in Alabama***", Geological Survey of Alabama, Circular 170, Tuscaloosa, Alabama 1993.
3) Perry O. Roehl, from the book "Carbonate Petroleum Reservoirs" page 622, Chapter title: " ***Depositional and diagenetic controls on reservoir rock development and petrophysics in Silurian Tidalites, Interlake Formation, Cabin Creek Field Area, Montana*** ".
4) R. Senger, F. Lucia, C. Kerans, M. Ferris and G. Foggy from Univ. of Texas at Austin and Univ. of California at Davis. " ***Dominant Control on Reservoir-Flow Behavior in Carbonate Reservoirs as Determined from Outcorp Studies*** "
5) O. Dubrule and H. Haldorsen, Sohio Petroleum Co., USA " ***Geostatistics for Permeability Estimation*** ".
6) M. Holmes and D. Tippie, "***Comparisons Between Log and Capillary Pressure Data to Estimate reservoir Wetting***" . SPE # 6856, October 1977
7) S. Cuddy, G. Allison and R. Steele, " *A Simple, Convincing Model For Calculating Water Saturations in Southern North Sea Gas Fields*", SPWLA 34th Annual Logging Symposium, June 1993

Figure 1

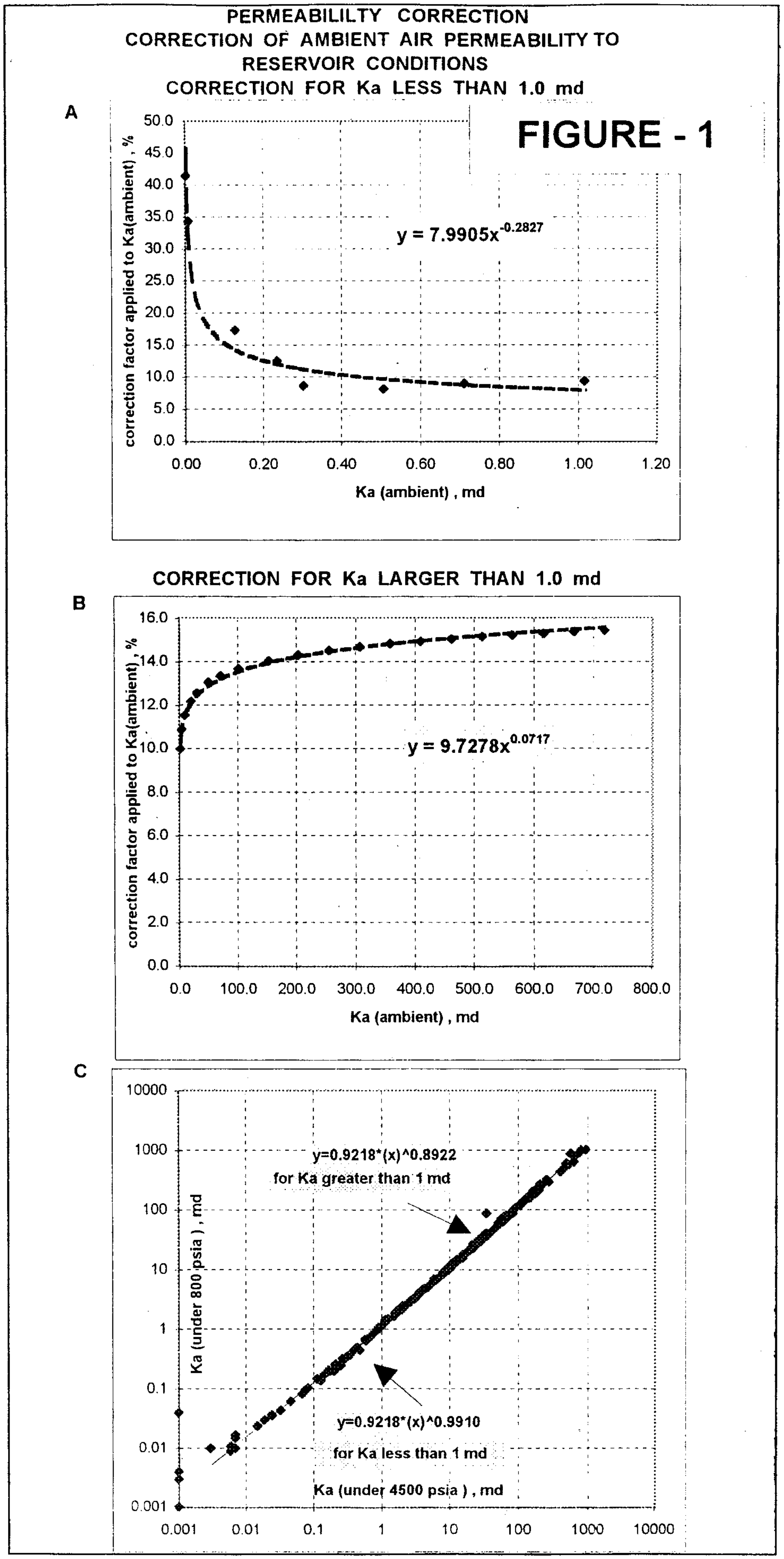
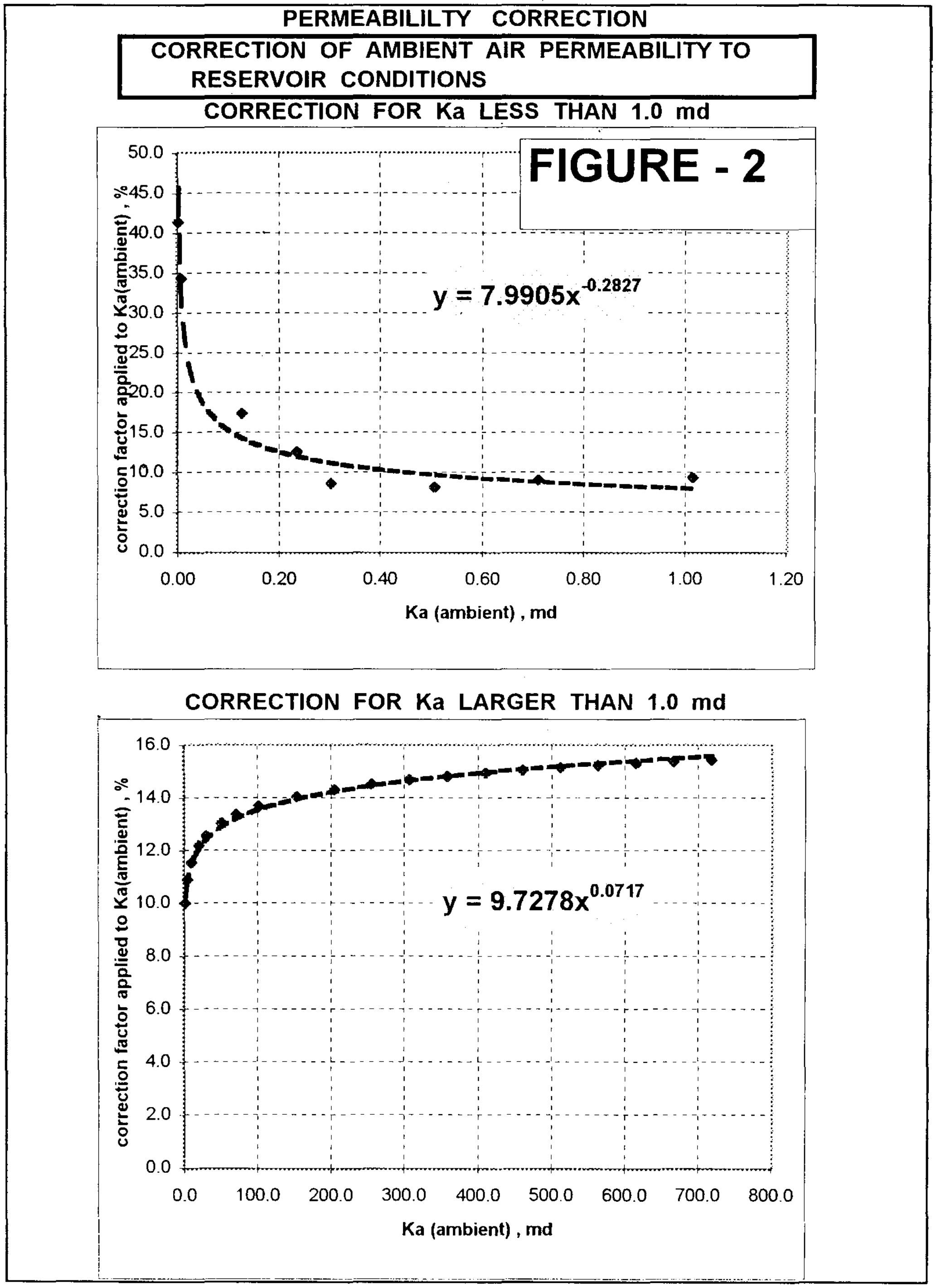

PERMEABILILTY CORRECTION
CORRECTION OF AMBIENT AIR PERMEABILITY TO RESERVOIR CONDITIONS
CORRECTION FOR Ka LESS THAN 1.0 md
A
FIGURE - 1
correction factor applied to Ka(ambient) , %
50.0
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
y = 7.9905x^-0.2827
0.00
0.20
0.40
0.60
0.80
1.00
1.20
Ka (ambient) , md
CORRECTION FOR Ka LARGER THAN 1.0 md
B
correction factor applied to Ka(ambient) , %
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
y = 9.7278x^0.0717
0.0
100.0
200.0
300.0
400.0
500.0
600.0
700.0
800.0
Ka (ambient) , md
C
10000
1000
100
10
1
0.1
0.01
0.001
Ka (under 800 psia) , md
y=0.9218*(x)^0.8922
for Ka greater than 1 md
y=0.9218*(x)^0.9910
for Ka less than 1 md
Ka (under 4500 psia) , md
0.001
0.01
0.1
1
10
100
1000
10000

Figure 2



PERMEABILILTY CORRECTION
CORRECTION OF AMBIENT AIR PERMEABILITY TO RESERVOIR CONDITIONS
CORRECTION FOR Ka LESS THAN 1.0 md
FIGURE - 2
y = 7.9905x^-0.2827
correction factor applied to Ka(ambient) , %
Ka (ambient) , md
0.00 0.20 0.40 0.60 0.80 1.00 1.20
0.0 5.0 10.0 15.0 20.0 25.0 30.0 35.0 40.0 45.0 50.0
CORRECTION FOR Ka LARGER THAN 1.0 md
y = 9.7278x^0.0717
correction factor applied to Ka(ambient) , %
Ka (ambient) , md
0.0 100.0 200.0 300.0 400.0 500.0 600.0 700.0 800.0
0.0 2.0 4.0 6.0 8.0 10.0 12.0 14.0 16.0

Example from rocks 7 and 8 showing distinguished mercury injection and recovery patterns for limestone and dolomite rocks FIGURE - 3

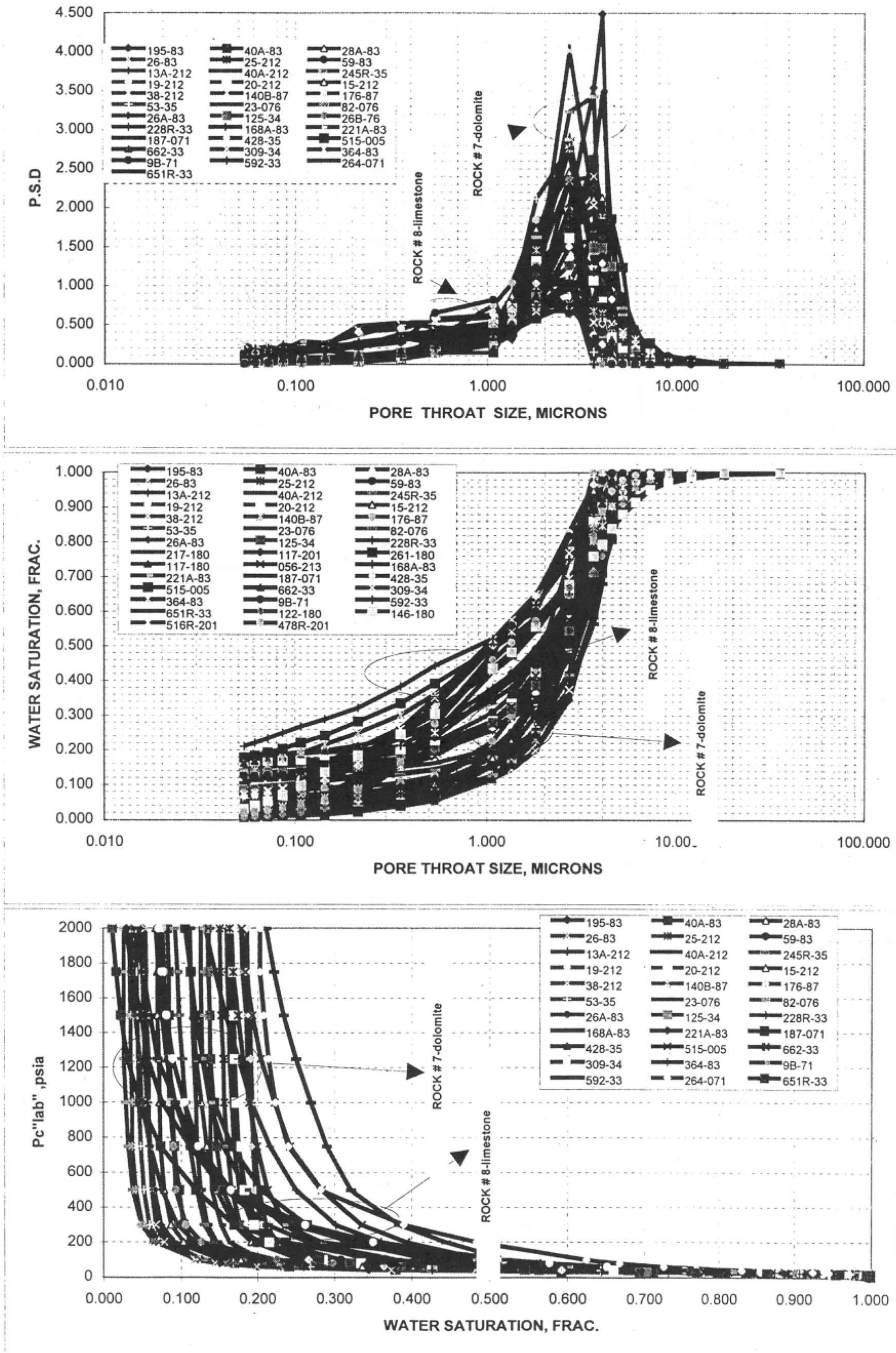
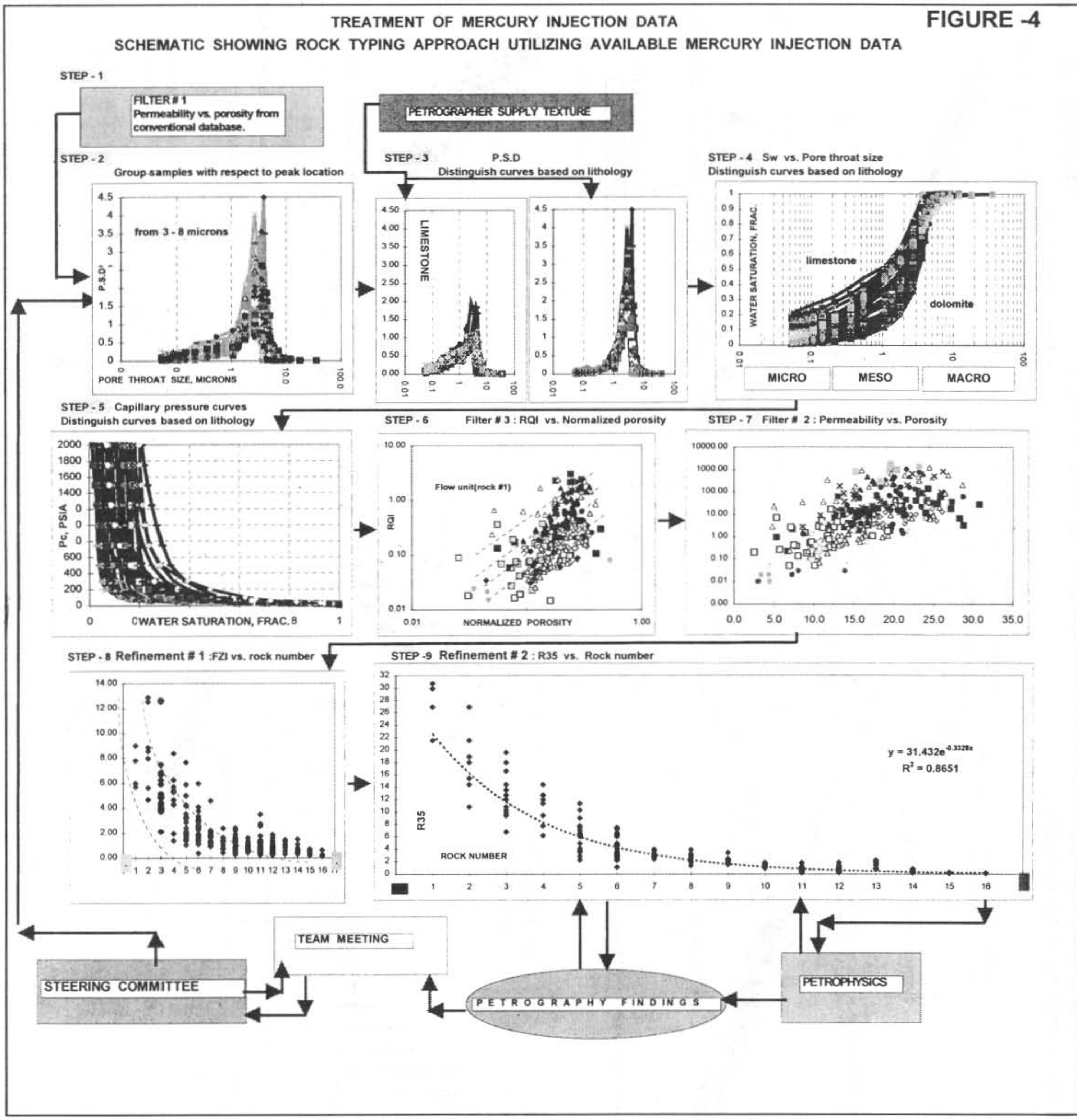
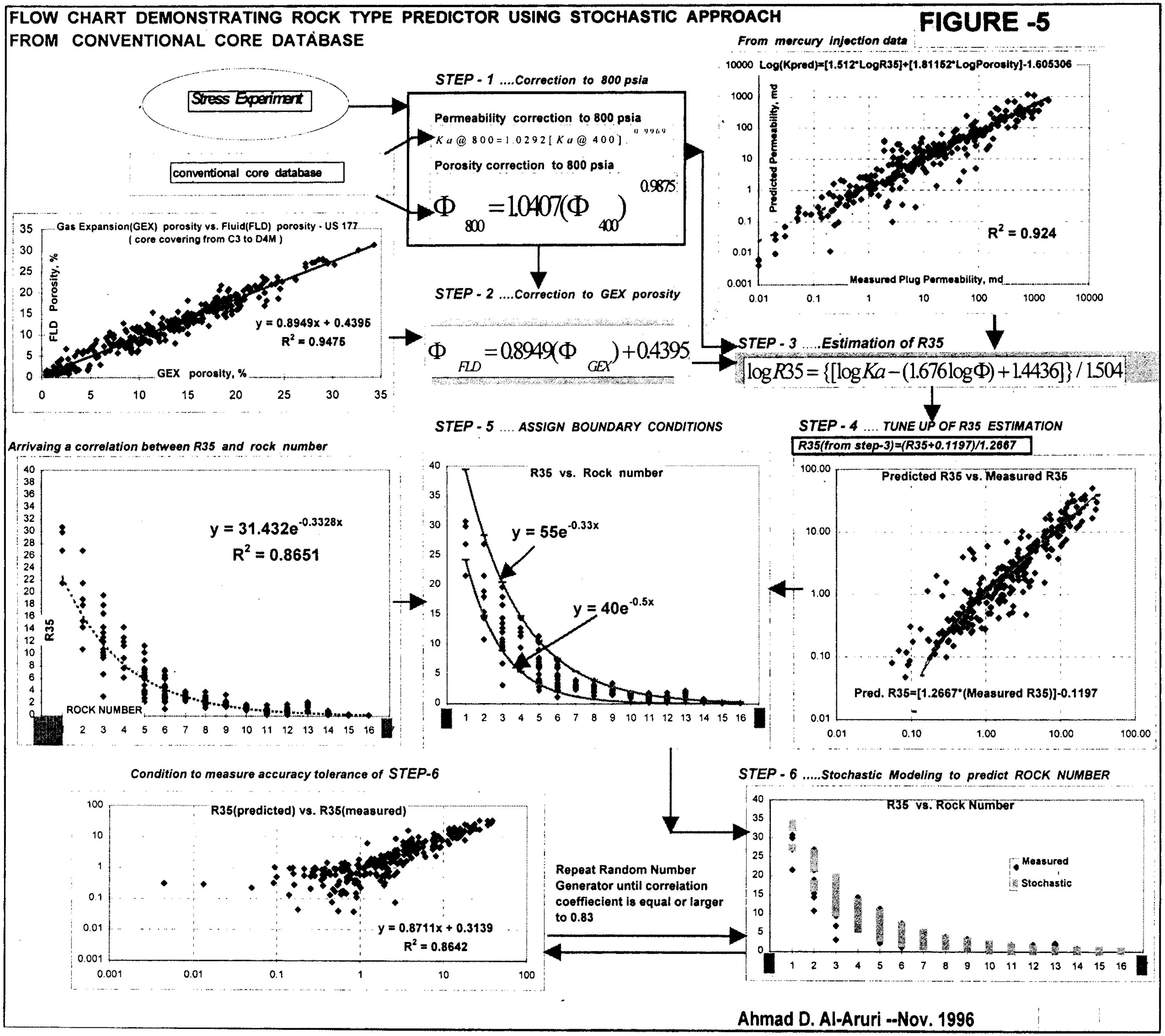


Figure 4



TREATMENT OF MERCURY INJECTION DATA
FIGURE -4
SCHEMATIC SHOWING ROCK TYPING APPROACH UTILIZING AVAILABLE MERCURY INJECTION DATA
STEP - 1
FILTER # 1
Permeability vs. porosity from conventional database.
PETROGRAPHER SUPPLY TEXTURE
STEP - 2
Group samples with respect to peak location
from 3 - 8 microns
P.S.D
PORE THROAT SIZE, MICRONS
STEP - 3
P.S.D
Distinguish curves based on lithology
LIMESTONE
STEP - 4 Sw vs. Pore throat size
Distinguish curves based on lithology
WATER SATURATION, FRAC.
limestone
dolomite
MICRO
MESO
MACRO
STEP - 5 Capillary pressure curves
Distinguish curves based on lithology
Pc, PSIA
WATER SATURATION, FRAC.
STEP - 6
Filter # 3 : RQI vs. Normalized porosity
Flow unit(rock #1)
RQI
NORMALIZED POROSITY
STEP - 7 Filter # 2 : Permeability vs. Porosity
STEP - 8 Refinement # 1 :FZI vs. rock number
STEP -9 Refinement # 2 : R35 vs. Rock number
$y = 31.432e^{-0.3329x}$
$R^2 = 0.8651$
R35
ROCK NUMBER
TEAM MEETING
STEERING COMMITTEE
PETROGRAPHY FINDINGS
PETROPHYSICS



FLOW CHART DEMONSTRATING ROCK TYPE PREDICTOR USING STOCHASTIC APPROACH FROM CONVENTIONAL CORE DATABASE
FIGURE -5
Stress Experiment
conventional core database
STEP - 1 ....Correction to 800 psia
Permeability correction to 800 psia
$Ka@800 = 1.0292[Ka@400]^{0.9969}$
Porosity correction to 800 psia
$\Phi_{800} = 1.0407(\Phi_{400})^{0.9875}$
STEP - 2 ....Correction to GEX porosity
$\Phi_{FLD} = 0.8949(\Phi_{GEX}) + 0.4395$
Gas Expansion(GEX) porosity vs. Fluid(FLD) porosity - US 177
(core covering from C3 to D4M)
FLD Porosity, %
GEX porosity, %
y = 0.8949x + 0.4395
R^2 = 0.9475
From mercury injection data
Log(Kpred)=[1.512*LogR35]+[1.81152*LogPorosity]-1.605306
Predicted Permeability, md
Measured Plug Permeability, md
R^2 = 0.924
STEP - 3 .....Estimation of R35
$\log R35 = \{[\log Ka - (1.676 \log \Phi) + 1.4436]\} / 1.504$
STEP - 4 .... TUNE UP OF R35 ESTIMATION
R35(from step-3)=(R35+0.1197)/1.2667
Predicted R35 vs. Measured R35
Pred. R35=[1.2667*(Measured R35)]-0.1197
STEP - 5 .... ASSIGN BOUNDARY CONDITIONS
R35 vs. Rock number
y = 55e^-0.33x
y = 40e^-0.5x
Arrivaing a correlation between R35 and rock number
y = 31.432e^-0.3328x
R^2 = 0.8651
R35
ROCK NUMBER
Condition to measure accuracy tolerance of STEP-6
R35(predicted) vs. R35(measured)
y = 0.8711x + 0.3139
R^2 = 0.8642
Repeat Random Number Generator until correlation coeffiecient is equal or larger to 0.83
STEP - 6 .....Stochastic Modeling to predict ROCK NUMBER
R35 vs. Rock Number
Measured
Stochastic
Ahmad D. Al-Aruri --Nov. 1996

Figure 5

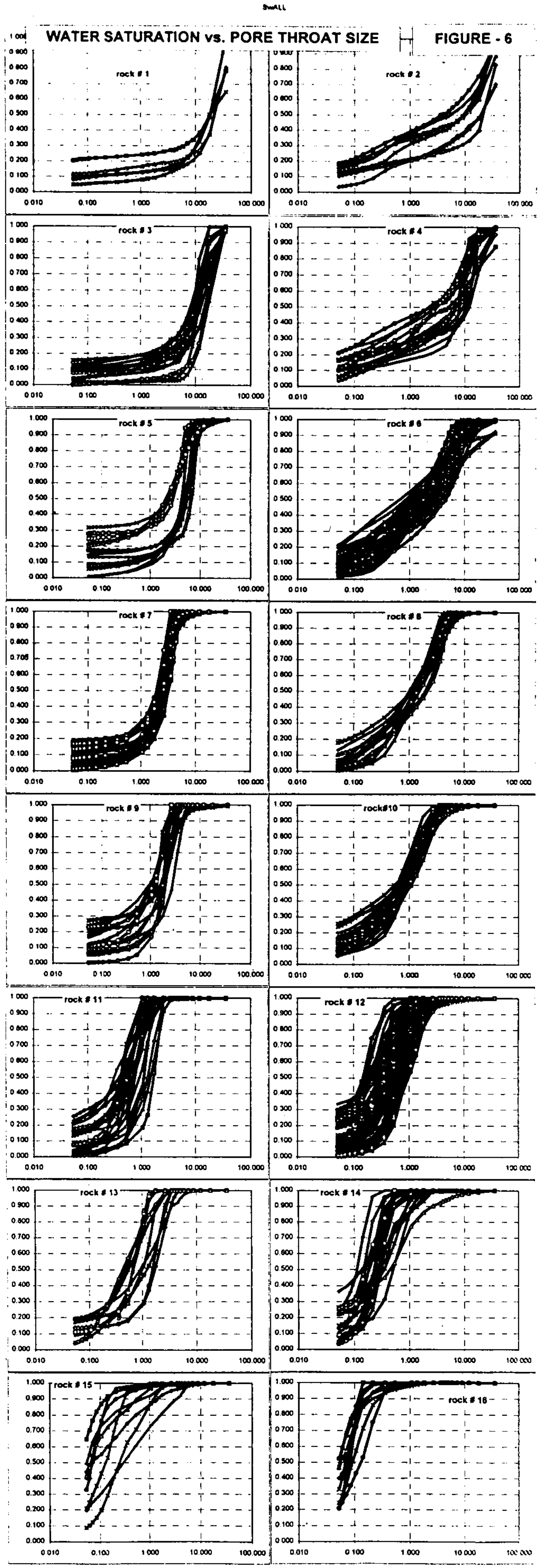


Figure 6

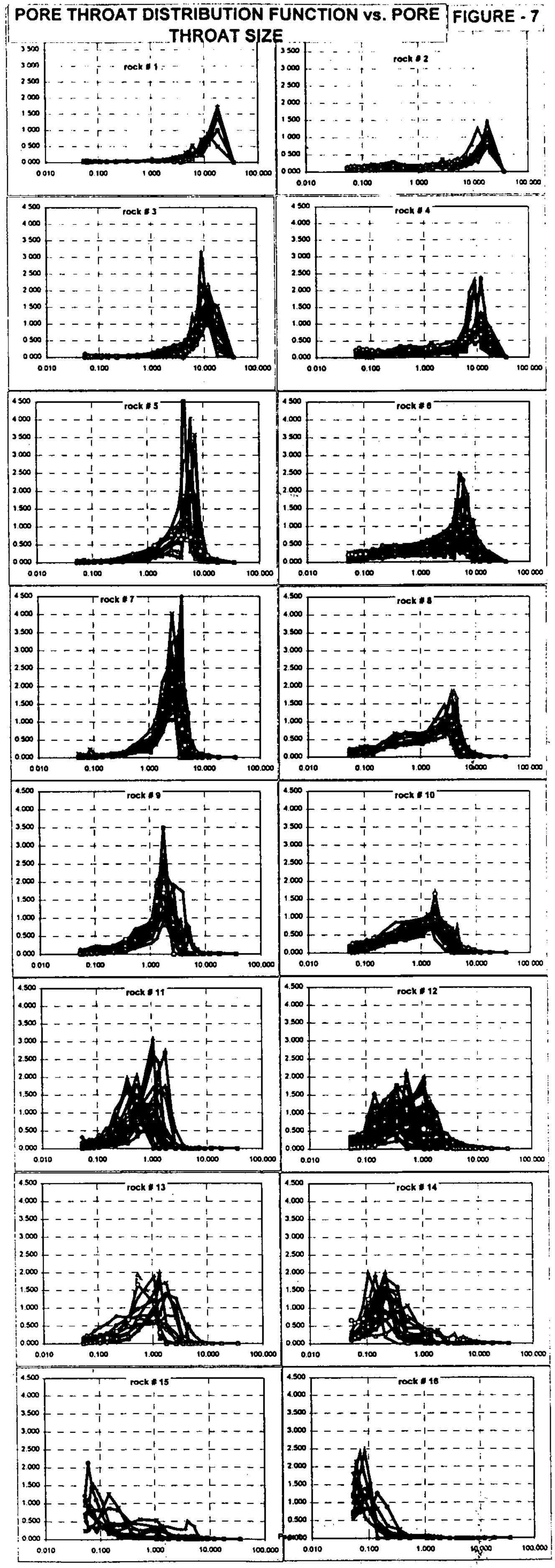

PORE THROAT DISTRIBUTION FUNCTION vs. PORE THROAT SIZE
FIGURE - 7
rock # 1
rock # 2
rock # 3
rock # 4
rock # 5
rock # 6
rock # 7
rock # 8
rock # 9
rock # 10
rock # 11
rock # 12
rock # 13
rock # 14
rock # 15
rock # 16
0.010
0.100
1.000
10.000
100.000

Figure 7

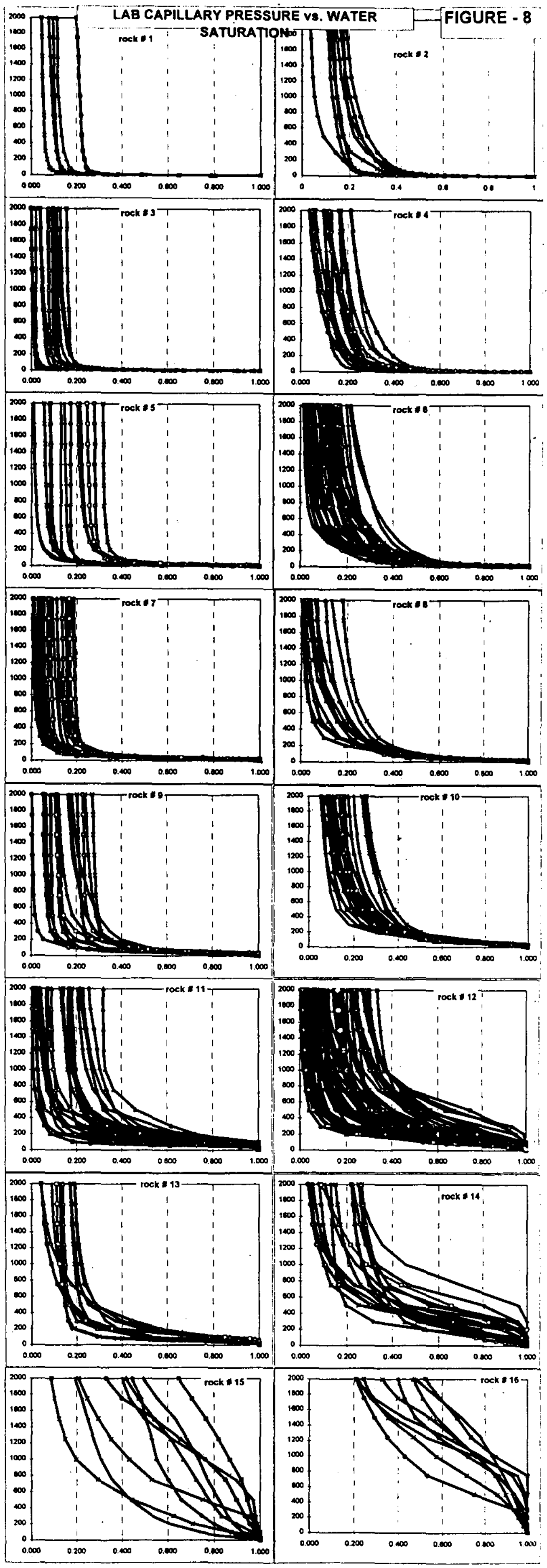

LAB CAPILLARY PRESSURE vs. WATER SATURATION
FIGURE - 8
rock # 1
rock # 2
rock # 3
rock # 4
rock # 5
rock # 6
rock # 7
rock # 8
rock # 9
rock # 10
rock # 11
rock # 12
rock # 13
rock # 14
rock # 15
rock # 16

Figure 8

POROSITY, PERMEABILITY & Swirr RELATIONSHIPS **FIGURE - 9A**

Figure 9 A

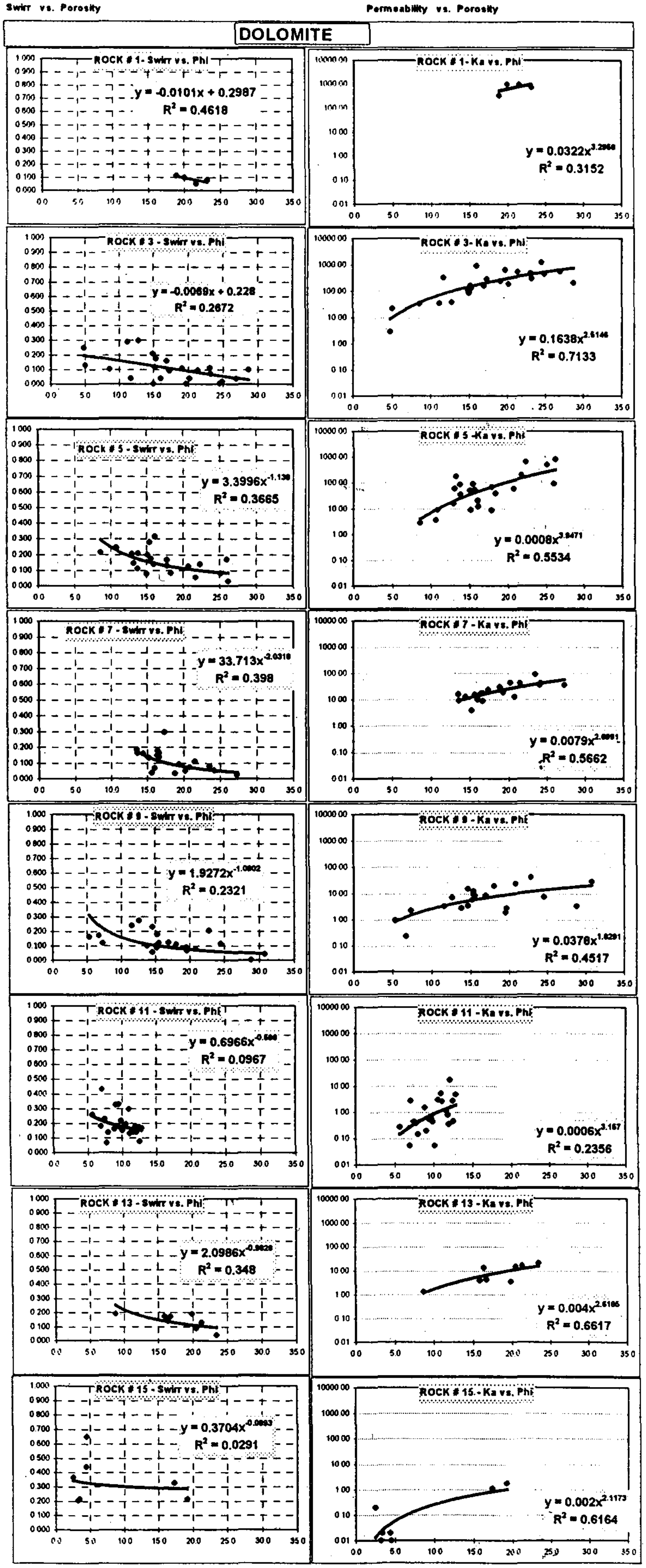
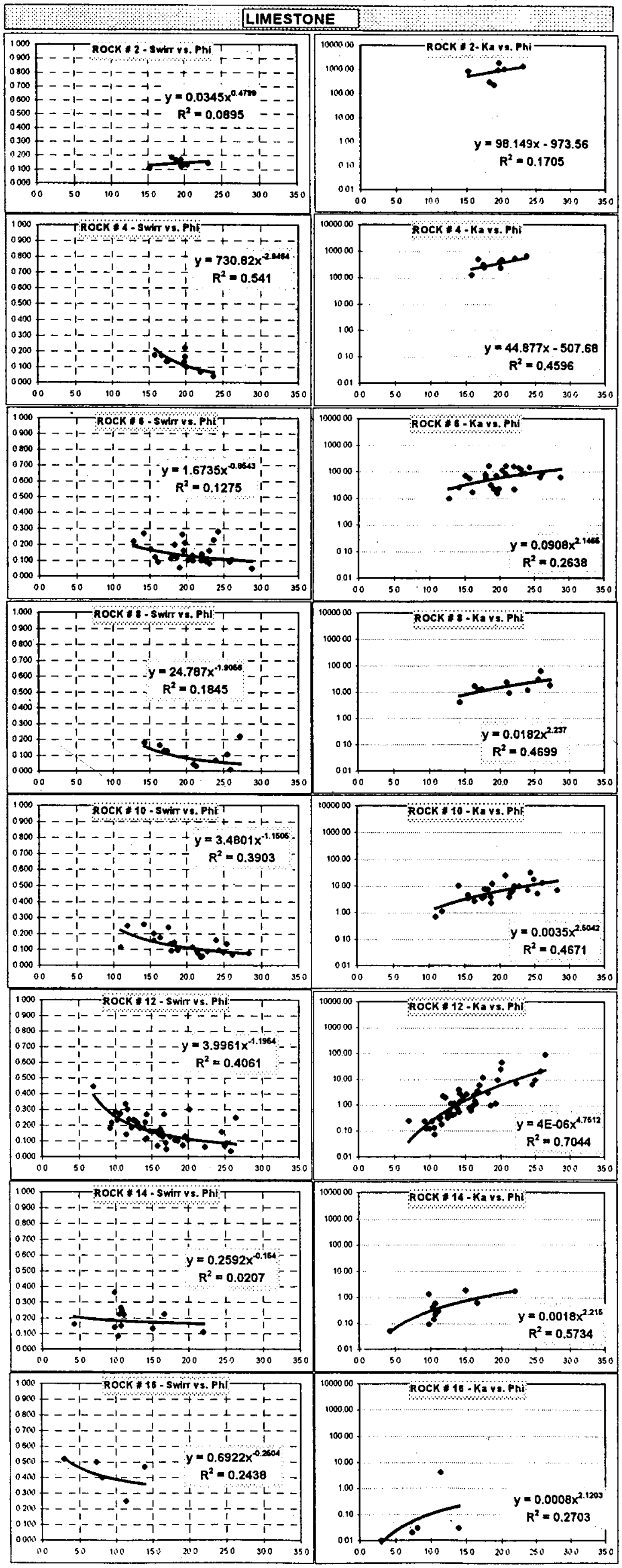


Figure 9 B

POROSITY, PERMEABILITY & Swirr RELATIONSHIPS FIGURE - 9B

Swirr vs. Porosity Permeability vs. Porosity



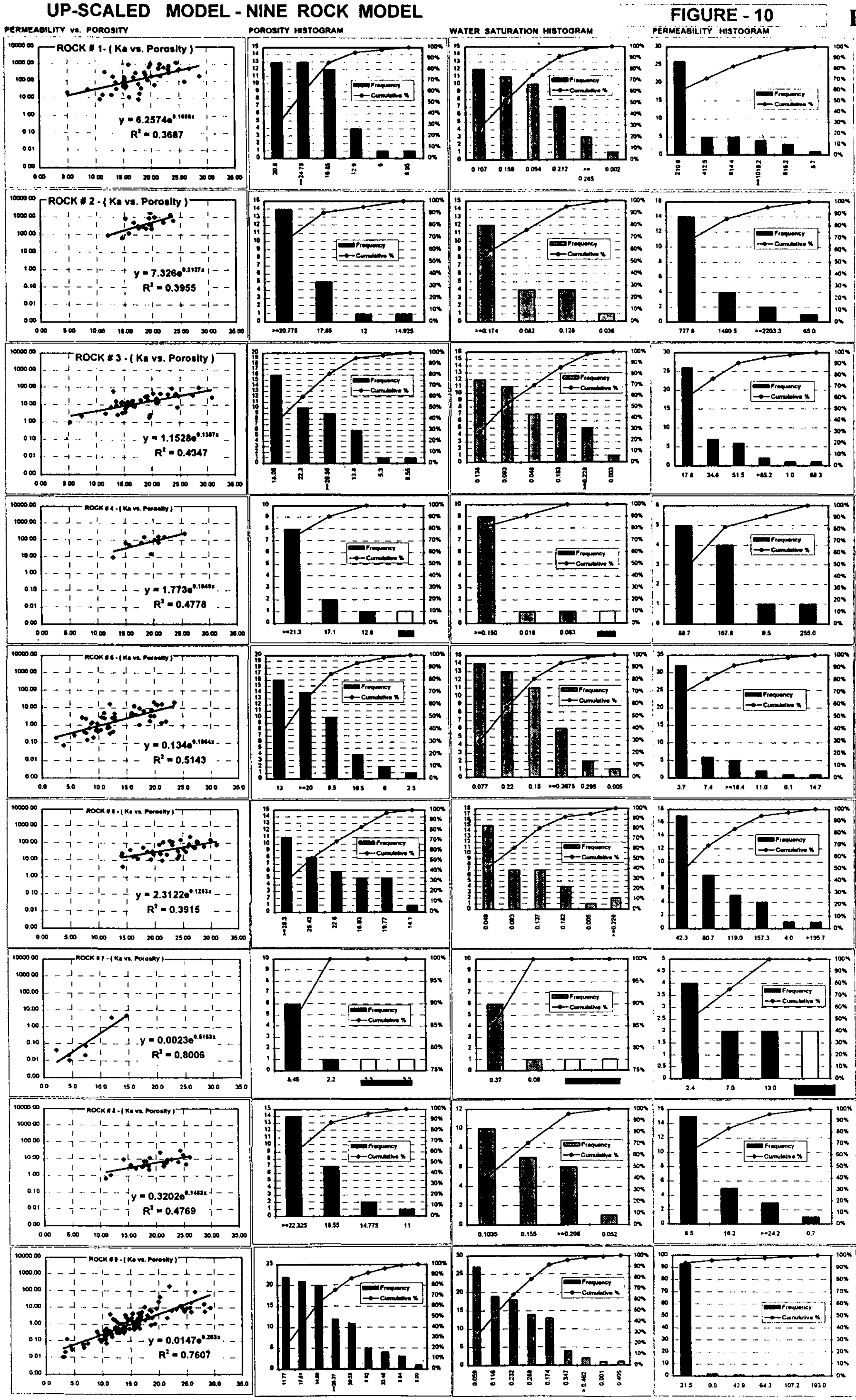
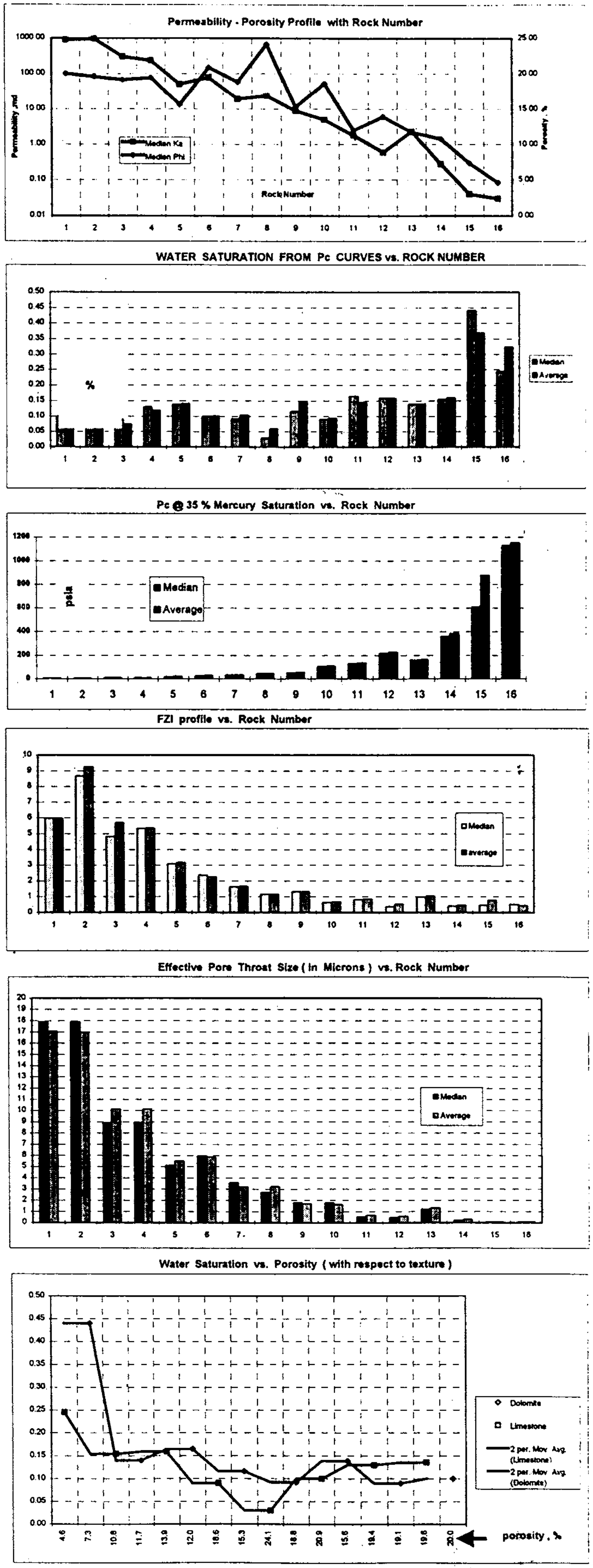

UP-SCALED MODEL - NINE ROCK MODEL
FIGURE - 10
PERMEABILITY vs. POROSITY
POROSITY HISTOGRAM
WATER SATURATION HISTOGRAM
PERMEABILITY HISTOGRAM
ROCK # 1 - (Ka vs. Porosity)
R² = 0.3687
ROCK # 2 - (Ka vs. Porosity)
R² = 0.3955
ROCK # 3 - (Ka vs. Porosity)
R² = 0.4347
R² = 0.4778
R² = 0.5143
R² = 0.3915
R² = 0.8006
R² = 0.4769
R² = 0.7607
Frequency
Cumulative %

Figure 10

CHARACTERISTICS OF THE 16-ROCK MODEL FIGURE - 11A

Figure 11 A



CHARACTERISTICS OF THE 16-ROCK MODEL FIGURE - 11B

Figure 11 B

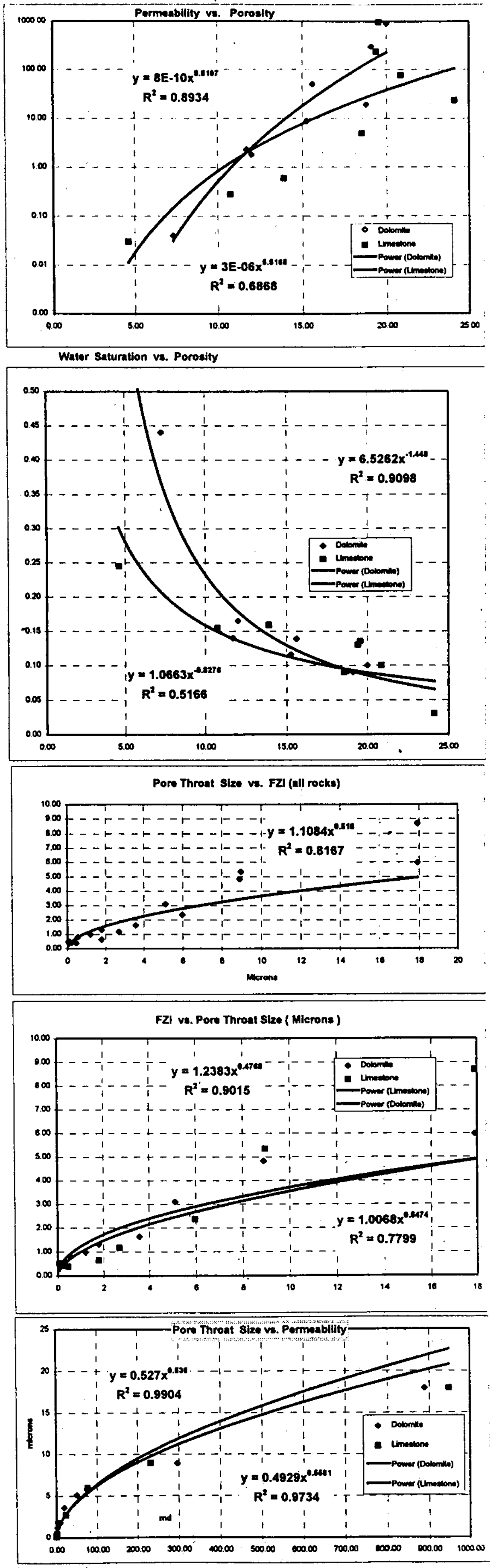


Figure 12

GELOGICAL CRITERIA FOR NINE ROCK MODEL AND RQI vs. NORMALISED POROSITY PLOTS FOR DOLOMITES & LIMESTONES **FIGURE - 12**

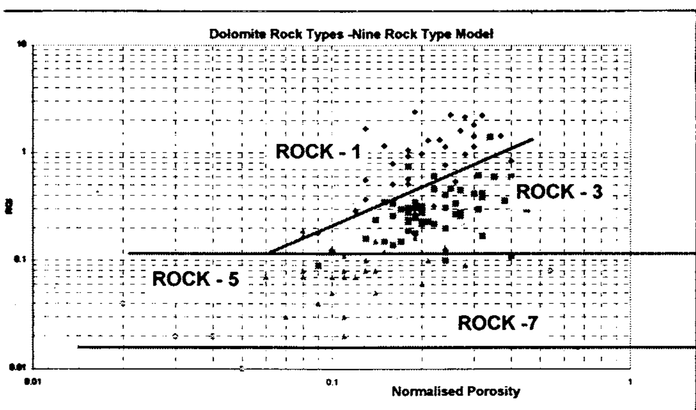
Dolomites

Rock Type # 9-Rock Type Model	Rock Type # 16-Rock Type Model	Criteria of Definition: Crystal Size	Pore Facies: InterXln	Pore Facies: Vuggy/Moldic	Normalised Porosity	RQI	R35
1	1, 3, 5	Fine 3-2 Micro 0-2	3-2	0-3	0.1-0.4	0.3-2.39	3.4-30.7
3	7,9	Micro 3-2 Crypto 0-3	2-3	0-2	0.1-0.45	0.1-0.75	1.39-7.4
5	11,13	Micro 3-1 Crypto 3-0 Fine 0-3	0-3	0-2	0.06-0.28	0.03-0.19	0.21-1.07
7	15	Crypto 0-3 Micro 3-0 Fine 0-3	0 Tightly Packed	0-1	0.02-0.05	0.01-0.04	0.05-0.1

Limestones

Rock Type # 9-Rock Type Model	Rock Type # 16-Rock Type Model	Criteria of Definition: Limestone Texture	Pore Facies: Intergran.	Organic	Matrix	Moldic/Vuggy	Normalised Porosity	RQI	R35
2	2,4	GRST 3 GRST/PKST 3-1/0-3	3-2	0-1	0	0-1	0.18-0.35	1.08-3.64	7.16-25
4	6a	PKST 3-2 GRST 0-2	2-3	1-0	0-1	0-1	0.17-0.38	0.57-0.94	4.13-7.67
6	6b / 8	PKST 3-2 GRST 0-1 WKST 0-1	2-1	0-2	1-0	2-0	0.15-0.45	0.17-0.93	1.62-4.06
8	10	PKST 2-3 WKST 0-2	1-0	0-1	1-2 rare 0	0-1	0.15-0.41	0.1-0.33	0.6-1.65
9	12,14,16	WKST 3-1 PKST 0-3 MDST 0-3	0-1	0-1	1-3 Rare 0	0-1	0.03-0.24	0.02-0.13	0.06-0.67

1=Rare 2=Common 3=Abundant



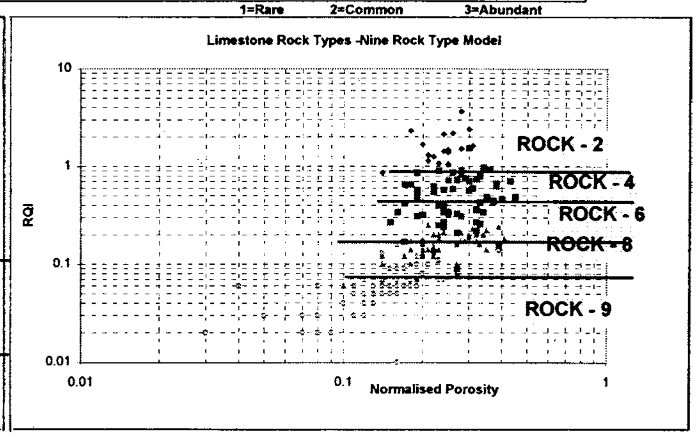
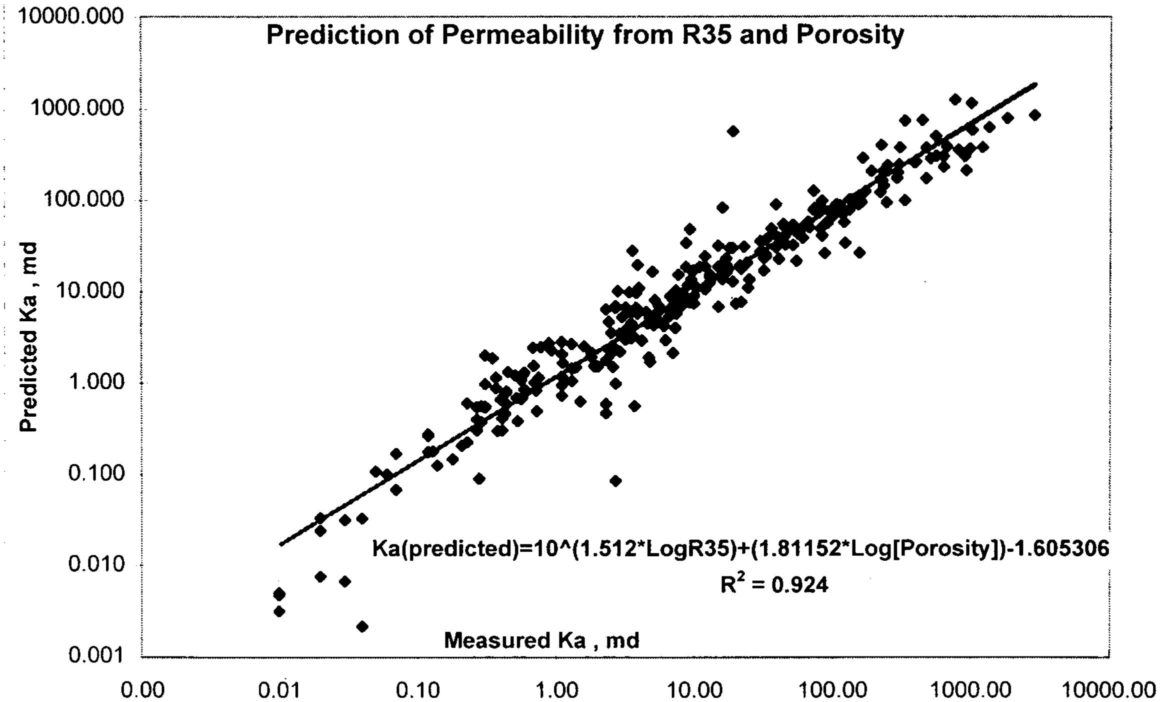


Figure 13

THE 9 - ROCK MODEL FIG.- 13

R35 RELATIONSHIP WITH POROSITY & PERMEABILITY vs. POROSITY



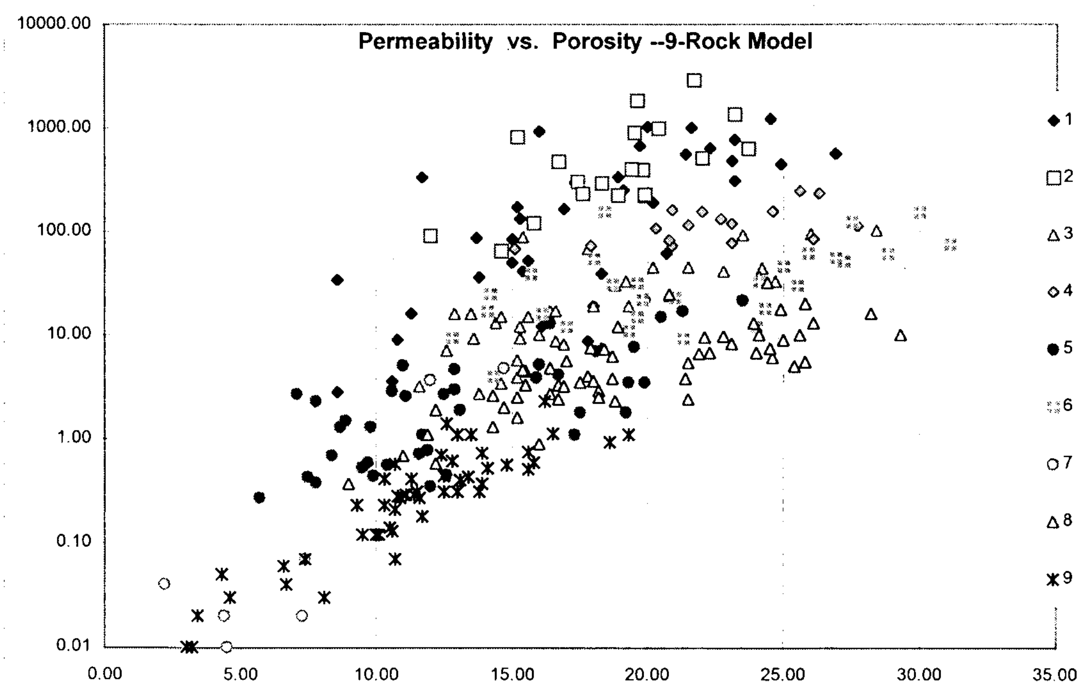
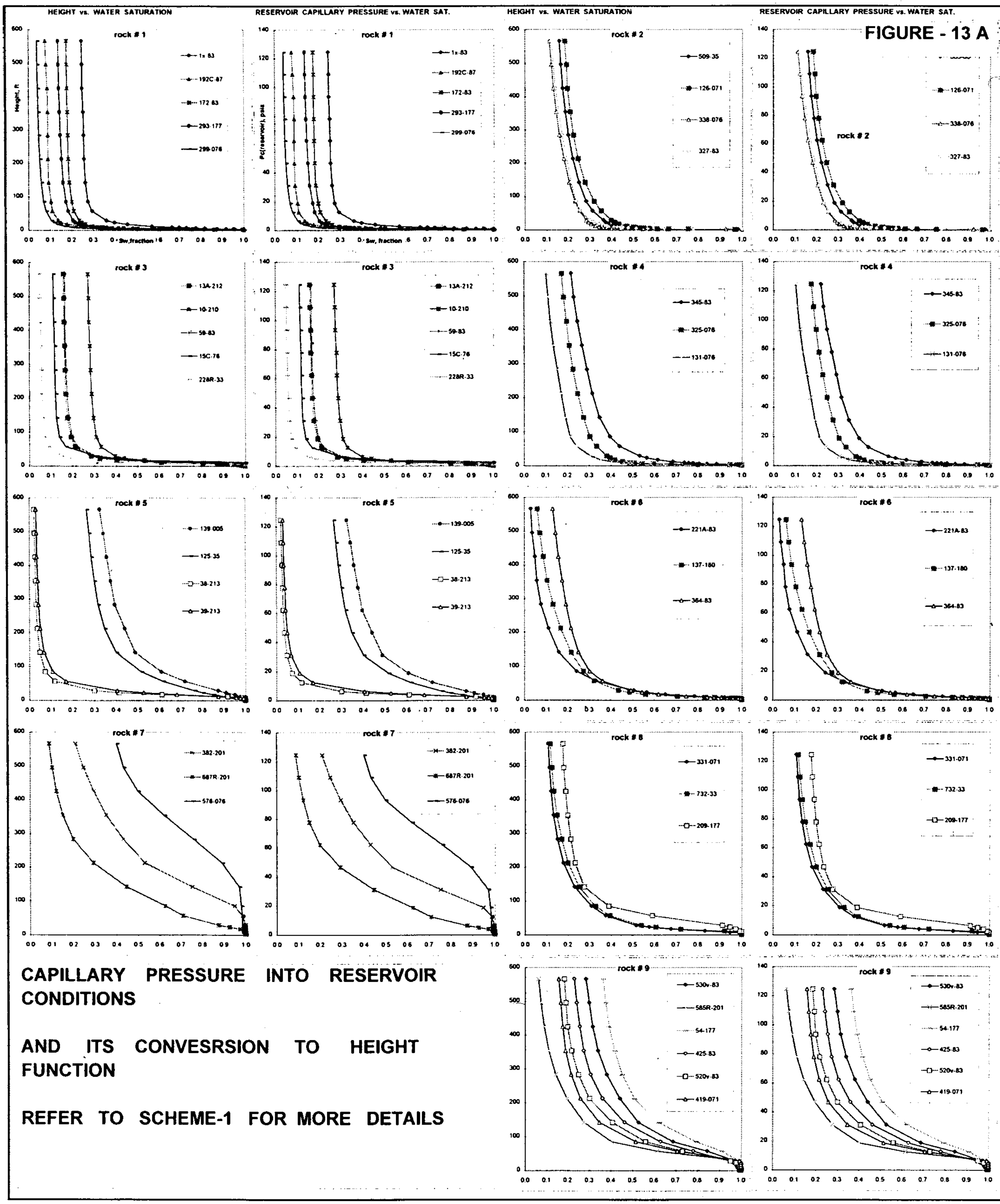


Figure 13 A



CAPILLARY PRESSURE INTO RESERVOIR CONDITIONS

AND ITS CONVESRSION TO HEIGHT FUNCTION

REFER TO SCHEME-1 FOR MORE DETAILS

Figure 13 B

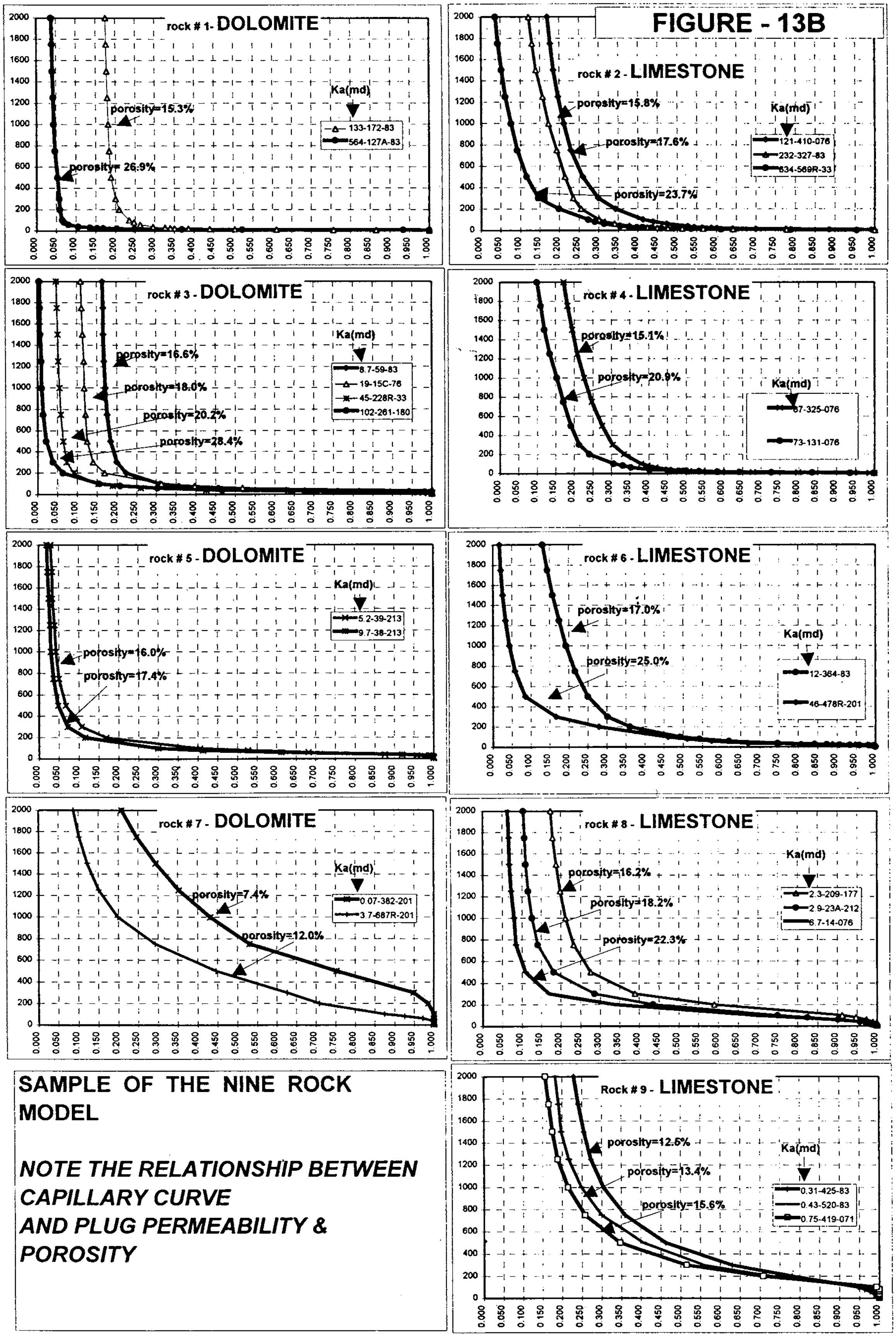


FIGURE - 13B
rock # 1 - DOLOMITE
porosity=15.3%
porosity= 26.9%
Ka(md)
133-172-83
564-127A-83
rock # 2 - LIMESTONE
porosity=15.8%
porosity=17.6%
porosity=23.7%
Ka(md)
121-410-076
232-327-83
634-569R-33
rock # 3 - DOLOMITE
porosity=16.6%
porosity=18.0%
porosity=20.2%
porosity=28.4%
Ka(md)
8.7-59-83
19-15C-76
45-228R-33
102-261-180
rock # 4 - LIMESTONE
porosity=15.1%
porosity=20.9%
Ka(md)
67-325-076
73-131-076
rock # 5 - DOLOMITE
porosity=16.0%
porosity=17.4%
Ka(md)
5.2-39-213
9.7-38-213
rock # 6 - LIMESTONE
porosity=17.0%
porosity=25.0%
Ka(md)
12-364-83
46-478R-201
rock # 7 - DOLOMITE
porosity=7.4%
porosity=12.0%
Ka(md)
0.07-382-201
3.7-687R-201
rock # 8 - LIMESTONE
porosity=16.2%
porosity=18.2%
porosity=22.3%
Ka(md)
2.3-209-177
2.9-23A-212
6.7-14-076
Rock # 9 - LIMESTONE
porosity=12.6%
porosity=13.4%
porosity=15.6%
Ka(md)
0.31-425-83
0.43-520-83
0.75-419-071
SAMPLE OF THE NINE ROCK MODEL
NOTE THE RELATIONSHIP BETWEEN CAPILLARY CURVE AND PLUG PERMEABILITY & POROSITY

SCHEMATIC SHOWING THREE MODELS: STOCHASTIC (16-ROCK), STOCHASTIC (9-ROCK) & DETERMINISTIC (9-ROCK)

FIG.-14

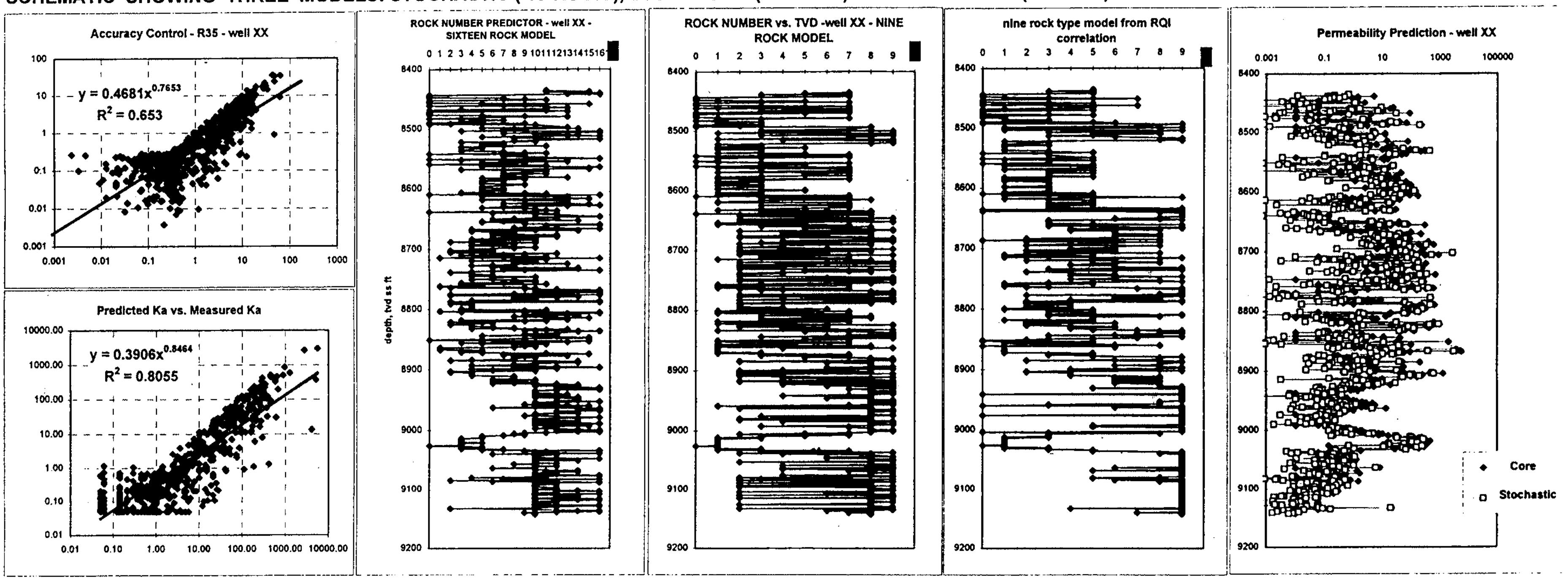


Figure 14

END POINTS ---- Swirr vs. Porosity

FIGURE - 15

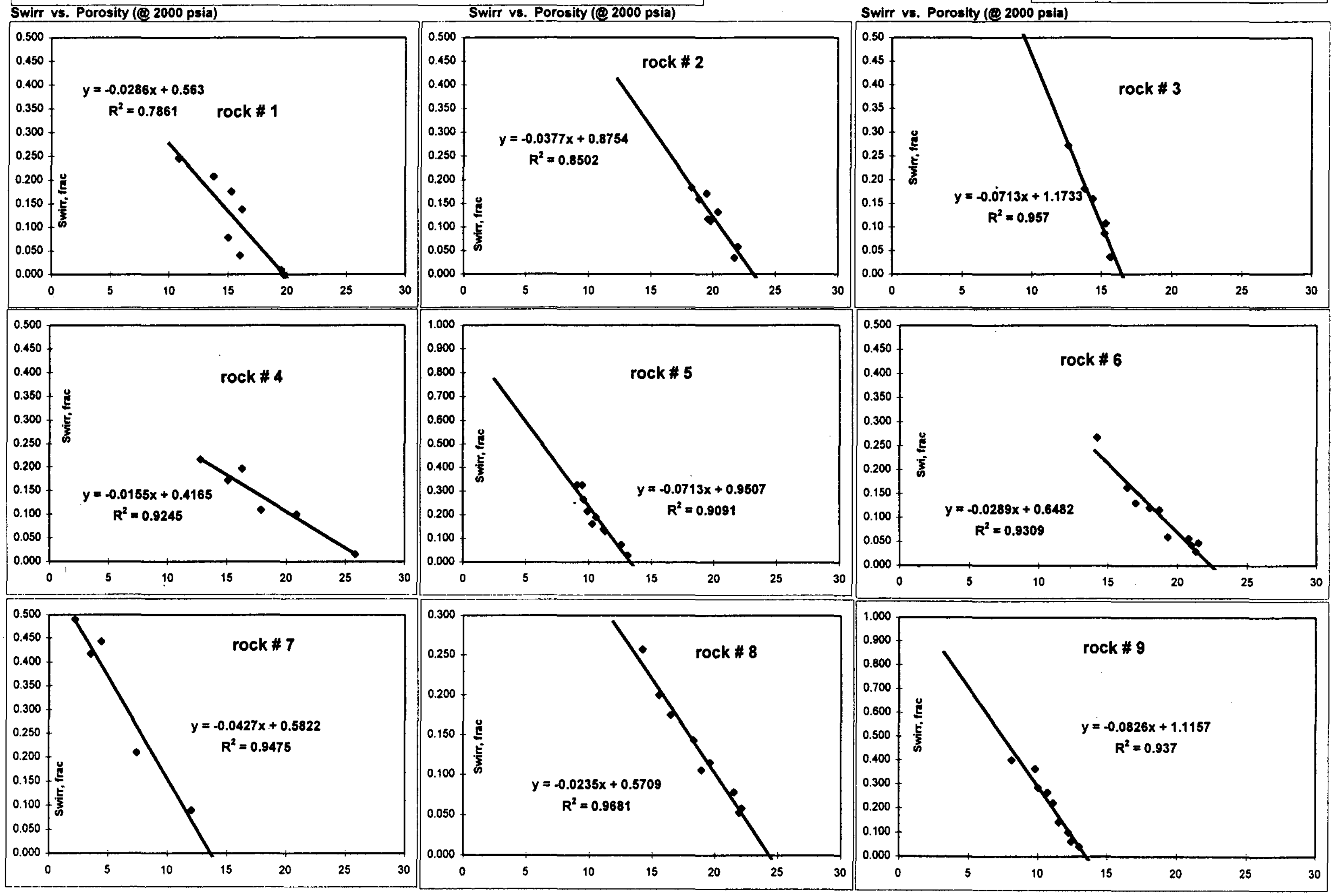


Figure 15

SCHEME - 1

$$P_{c-oil/brine} \equiv P_{c-air/Hg} \times [(\sigma_{oil/brine} \times \cos\theta_{oil/brine}) / (\sigma_{air/Hg} \times \cos\theta_{air/Hg})]$$

$P_{c-air/Hg} \equiv$ Air-Mercury capillary pressure, psia also defined as lab Pc.

$P_{c-oil/brine} \equiv$ Oil-Brine capillary pressure, psia also defined as reservoir Pc.

$\theta_{oil/brine} \equiv$ Contact angle between oil and brine, degrees from literature usually its 30 degrees. However SPE # 6856 by Holmes and Tippie (October 1977) recommended to use **50** degrees for medium wet carbonate reservoirs.

$\sigma_{oil/brine} \equiv$ Interfacial tension between oil and brine (which simulates reservoir conditions). Number to use from literature was 30. TOTAL reported a value of **36** dynes/cm. in a smple taken from US21/1 (Arab-D4)

$\theta_{air/Hg} \equiv$ Contact angle between air and mercury in degrees. Usually a value of 140 degrees is used. MOBIL reported a value of **150** degrees recently.

To calculate height above free water level, the following equation is used:

$$H = \frac{[P_{c-oil/brine}]}{[\rho_{water} - \rho_{oil}]}$$

$H \equiv$ Height in feet

$\rho_{water} \equiv$ Water density gradient = **0.50** psi/ft at reservoir conditions

$\rho_{oil} \equiv$ Oil density gradient = **0.28** psi/ft at reservoir conditions

$\sigma_{air/Hg} \equiv$ Interfacial tension between air and mercury. Value to be used is **485** dynes/cm.