

PETROPHYSICAL CHARACTERIZATION OF CARBONATE NATURALLY FRACTURED RESERVOIRS FOR USE IN DUAL POROSITY SIMULATORS

Héctor Pulido^{1,2}, Fernando Samaniego¹, Guadalupe Galicia-Muñoz¹, Jesus Rivera R.¹ and Carlos Vélez¹

1. UNAM, 2. Pemex,
Tomatla 25 Colonia Santo Domingo
Delegación Coyoacan C.P. 04359, México, D. F.
e-mail: hcpulidob@pemex.pex.com

ABSTRACT

This study shows how multiporous system is grouped and the parameters obtained by means of a petrophysical characterization are used in a dual porosity simulator.

Carbonate naturally fractured reservoir is a multiporous system that contain microfractures, fractures, vugs, macrovugs, matrix, type of fractures network.

Because they must be incorporate into the Numerical Model of Simulation the results of the petrophysical characterization, it is conceptualized like a model of double porosity.

Porosity of pseudomatrix. To the matrix porosity the porosity of the microfractures are grouped in one porous media.

Secondary porosity. The vugs and the fractures are grouped in other porous media.

In carbonated naturally fractured reservoir, the Jurassic tectonic generated faults, the zones near these generate *runners of fractured zones* which increases the secondary porosity in addition dolomitization process and dissolution. In geothermal or volcanics reservoir the are generated fractures and their *runners of fractured zones* by different processes, the main fractures are one porous media and microfractures are the secondary media due to their conection with the first porous media.

INTRODUCTION

The new well location of a drilling well requires to define zones with greater cumulative and producing potential that show the simulators. Petrophysical characterization is a focused method to diminish the risk of perforating wells with low productivity.

Developments Concepts

In a *petrophysical model* their variables are the properties of the rock and their coefficients and exponents are their parameters. In order to represent the matrix, the secondary system and the system of double porosity, the parameters differ in their values.

In a *mixing model*, the system variable is a mixing of two porous media, it is dominated by weight

functions on each porous media, there are static and dynamic. The *new petrophysical model of double porosity* is the *set of mixing models*, so much previously published as the new ones developed in this work.

Petrophysical Characterization Models are the set of *petrophysical models* and *mixed models* for multiporous systems with the purpose of obtained all the properties that can be modeled their three-dimensional variability.

The petrophysical characterization involve concepts of geomechanics such as for calculation of system compressibility using logs and the matrix using cores. The process considerations are: *matrix* petrophysical properties, the *dual porosity system* and the *secondary* system are represented correctly with models of petrophysical characterization. The *petrophysical characterization models* must correspond to the elements and their behavior of carbonated naturally fractured reservoir, reason why they are useful in the obtaining of petrophysics parameters because the exact relations between the characteristics of the rock often do not exist due to the complexity and to the variation of the composition of the rock, of the structure of the pore, and other intrinsic characteristics.

The petrophysical variables are the base to obtain dynamic variable, these you complete when introducing themselves to the simulator become parameters that characterize to the reservoir.

In a numerical simulation model the variables are x, y, and, z and time and the parameters are the characteristics of the rock and the fluid. Using *dynamic models* altogether with the results of the matrix, the system of dual porosity and the secondary system *dynamic parameters* are obtained that are vital to calculate the oil forecasting under different schemes. The *production history* of the reservoir is used for to match the dynamic parameters.

Geophysical logs gives measurements petrophysical properties of the *dual porosity system* (Now conceptualized), applying the *petrophysical characterization* to the *dual porosity* system, allows to obtain their properties such as: the total porosity, cementation exponent of system, channels equivalent

radius, formation factor, permeability, compressibility, saturation exponent, water saturation. The petrophysical characteristics of sixty cores of 7 producing carbonated oil reservoirs were evaluated in laboratory varying the confinement pressure; applying the *matrix petrophysical characterization* allows to obtain his properties such as: porosity, formation factor, exponent of cementation, pore throat radius, irreducible water, permeability, compressibility, saturation, capillary pressure and the sonic speeds. (Is necessary to separate cores with high secondary porosity) The *petrophysical characterizations of the matrix*, the *system of double porosity* and the *new petrophysical model of dual porosity* allow to obtain the *petrophysical characterization of secondary system*. They are valid within the specific intervals and they are based on experimental data required to calibrate itself and to obtain its coefficients, they allow to calculate properties and to predict in zones where only there are logs.

When increases the fracturing intensity, the system cementation exponent diminishes, tend to increase the secondary porosity, fracture width, the permeability are greater when they are close to the fault.

In zones so far to the fault the primary porosity is not altered, but the secondary porosity has smaller values to the zones than near of the fault, also all the other parameters secondary. The zones of influence are called *runners of the fractures zone*.

The *discretización of total porosity* in matrix porosity and secondary porosity, is making using conventional geophysical logs, in addition to framework (criteria set) of geologic (structural and sedimentology, petrography, mineralogy and paleontology), geophysical, petrophysical and reservoir engineering (To see **Figs. 1-8**).

Matrix petrophysical characterization

The new petrophysical model of double porosity incorporates the properties of secondary matrix and and generating the one of the system that is the mixture in which the influence of the secondary volumetric fraction stands out.

The sixty samples of core were collected of 7 carbonated oil reservoirs producing in Jurassic Kimmeridgian Upper .

The core first were cut in cylindrical form of 3,8 centimeters of diameter and 6,4 centimeters in length and cleaned in extractors of tolueno/methanol to remove or to clear the oil and the salt.

The superficial vugs were filled of nonconductive material epoxy. After drying in a furnace to the emptiness by 7 days to °C. Once made previous the samples of core they were ready for the measurements.

Matrix porosity

Matrix porosity was measured varying the overload pressure. The porosity slightly diminishes, in agreement the overload pressure increases as of 1000 to 7000 psi. The diminution of the porosity is caused by the diminution of the porous volume. The porosity in core JSK-E and JSK-D is show in **Figure 9**.

Matrix formation factor

The resistivity of the completely saturated matrix is proportional to the resistivity of salt water, the constant is the matrix formation factor:

$$R_{oma} = F_{ma}R_{wma} \quad (1)$$

where:

R_{oma} = resistivity of the matrix saturated completely with salt water

R_{wma} = resistivity of the brine in the matrix.

Resistivity in core saturated completely with salt water was measured to different overload pressures. Brine resistivity (salinity = 200,000 ppm) without gas to represent the water of formation of carbonate was measured to 21 °C (°F 70).

Matrix formation factor calculated for different overload pressures:

$$F_{ma} = \frac{R_{oma}}{R_{wma}} \quad (2)$$

Matrix formation factor

The model of Archie correctly represents the relation between the matrix formation factor with the matrix porosity is given by:

$$F_{ma} = \frac{1}{\phi_{ma}^{m_{ma}}} \quad (3)$$

Figure 10 shows to a graph log-log of the behavior of matrix formation factor versus matrix porosity for different lithostratigraphy units considering the point theoretical ($\phi_{ma} = 1, F_{ma} = 1$).

The high formation factor and its great increase with the pressure in cores JSK-D of the sample are due to the conductive channels of the sample that are closing.

Matrix cementation exponent

The simultaneous measurement of matrix porosity and its formation factor allow to calculate its to different overload pressures.

$$m_{ma} = \frac{\ln(F_{ma})}{-\ln(\phi_{ma})} \quad (4)$$

When the conductive channels of a base (for the liquid and the electricity) are fine, the formation factor is great and highly employee in the pressure because the fine channels are less conductors and

easy to close itself because the pressure increases.

Figure 11 show cementation exponent vs net pressure of the JSK-E and cores of the JSK-D.

Matrix permeability was measured in cores with minimum secondary porosity varying the overload pressure from 1000 to 7000 psi in JSK-E and JSK-D, the matrix permeability diminished of 5 to 18 percents.

The diminution of the permeability is caused by some fine channels that are closed. The amplitude of the diminution of the permeability is employee of the closing of fractures, micro fractures, the throats of pore and diminutions of diameters of the microvugs.

Matrix permeability vs net pressure is shown in **Figure 12**.

Matrix cementation exponent

A rock with high porosity can have low permeability if the pores poorly are connected, and a rock of low porosity can have discharge permeability if the pores very are connected through throats.

When increases the overload pressure, increases the matrix cementation exponent, then changed the morphology and pore throat radius.

When increases the matrix cementation exponent, then decrease the pore throat radius (To see **Figure 13**):

$$m_{ma} = 10^9 R^{-20} \quad (5)$$

where:

m_{ma} = matrix cementation exponent.

R = pore throat radius, micrometers.

Using a new model and conventional logs (Pulido and Vélez, 2007):

$$m_{ma} = \frac{\ln\left(\frac{\phi_t^{m_{syst}} - f\phi_t}{1-f}\right)}{\ln(\phi_{ma})} \quad (6)$$

Matrix porosity and permeability

The relation between the porosity and the permeability of matrix is possible if is used the pore throat radius.

The data show that when the matrix permeability increases the matrix porosity increases in form of Power:

$$k_{ma} = \phi_{ma}^{10^9 R^{-20}} \quad (7)$$

where:

k_{ma} = matrix permeability, mD.

ϕ_{ma} = matrix,porosity, fraction.

Matrix resistivity index

Matrix resistivity index based on the matrix

formation factor is obtained:

$$I_{ma} = \frac{R_{t_{ma}}}{R_{o_{ma}}} = \frac{R_{t_{ma}}}{F_{ma} R_{w_{ma}}} \quad (8)$$

where:

$R_{t_{ma}}$ = total resistivity of the matrix saturated.

Matrix resistivity index based on matrix water saturation using the model of Archie (To see **Fig. 15**):

$$I_{ma} = S_{w_{ma}}^{-n_{ma}} \quad (9)$$

where:

n_{ma} = matrix saturation exponent.

Matrix saturation exponent

Total resistivity was measured in several occasions in cores at diverse brine saturations in certain pressure.

$$n_{ma} = \frac{\ln(I_{ma})}{-\ln(S_{w_{ma}})} \quad (10)$$

Figure 7. Each point represents one value of saturation exponent with a deep is necessary to use variable *saturation exponent*

Matrix formation compressibility,

Expressed in terms of its reduction of the matrix porous volume when increasing the net pressure:

$$c_{fma} = -\frac{1}{V_{pma}} \frac{dV_{pma}}{dp} = \frac{-1}{\phi_{ma}} \frac{d\phi_{ma}}{dp} \quad (11)$$

where:

V_{pma} = porous volume of matrix

P = net pressure, psi

V_b = total volume of rock, porous volume more solids volume, L³.

Using the model of porosity and permeability an equation of of the based on the permeability and the pressure is obtained

$$c_{fma} = \frac{1}{(k_{ma}/10^4)^{1/2n_{ma}}} \frac{d(k_{ma}/10^4)^{1/2n_{ma}}}{dp} \quad (12)$$

$$c_{fma} = \frac{1}{(k_{ma})^{1/2n_{ma}}} \frac{d(k_{ma})^{1/2n_{ma}}}{dp}$$

Matrix capillary pressure

Matrix capillary pressure were measured in cores JSK-E and core JSK-D having used gas to move the brine. The residual water saturation is determined of the capillary curve (To see **Fig. 16**).

$$P_{cm} = P_{em} S_{wm}^{-1/\lambda_{ma}} = P_{em} (I_{ma}^{-1/n_{ma}})^{-1/\lambda_{ma}} \quad (13)$$

where:

P_c = matrix capillary pressure, psi.

P_e = matrix capillary pressure at the beginning of the displacement, psi.

λ = exponent of pore distribution (Corey).

Figure 8. Is the behavior of the capillary pressure vs the salt water saturation

Dimensionless capillary pressure (Li and Williams, 2006):

$$P_{cD} = I_{ma} \beta \quad (14)$$

Where:

β = reciprocal of the multiplying the saturation exponent and the distribution exponent.

$$P_{c_m D} = \frac{P_{cm}}{P_{em}} = \text{dimensionless capillary pressure.}$$

Residual water saturation

A similar relation for the rocks was derived from carbonate that can be used qualitatively to obtain the:

$$S_{wr} = \frac{10 \phi_{ma}^{m_{ma}}}{\sqrt{k_{ma}}} \quad (15)$$

where:

S_{wr} = irreducible water saturation.

Matrix formation factor vs. matrix permeability.

The better adjusts and is shown in **Figure 11.**

$$\ln(F_{ma}) = -0.288 \ln(k_{ma}) + \ln(188.9) \quad (16)$$

The numerical dispersion between the data and good-fitted the line exists, although a tendency is clear that it demonstrates that whereas the permeability increases, formation factor diminishes.

This confirms with theory that the resistance of the formation factor of a gets much water saturation whereas the increases of the permeability due to the increasing electrical conductivity so that the factor of the formation must diminish.

Sonic speeds

After the cores were cleaned in an extractor of to again clear the salt and dried methanol in a furnace of the emptiness. The sonic speeds, of compression and speed of shears, were measured against the pressure that the sonic speeds in the samples saturated with gas of the base against porosity to 3000psi as it is in **Fig. 18.**

The same speeds when the samples were saturated with an oil of 25° API. and they decrease against the increases of the porosity but the data disperse in both figures gas-saturated and saturated oil as it is in

System (Total) porosity

Using the conventional corrections in logs such as: environmental and lithological, the total porosity is obtained.

System cementation exponent

The cementation exponents represent the degree of secondary porosity, vary of rock to rock, formation to formation, reservoir to reservoir, layer to layer. The value of m=1 everything is fracture and values until of 4 the rock is compact, for the limestone matrix the values walk from 2 to 2,5 and for fractured reservoirs the value is from 1,3 to 1.9. The intensity of fractures and vugs modify the exponent of initial cementation, when they increase to the fractures and the vugs, diminishes the system cementation exponent.

Using a Elkewidy's Model:

$$\phi_{sec} = \frac{\phi_t^{m_{syst}} [\phi_t - 1]}{\phi_t^{m_{syst}} - 1} \quad (17)$$

Pseudolinealizing the equation

$$\phi_{sec} = [1 - 0.74\phi_t] \phi_t^{m_{syst}} \quad (18)$$

Solving the system the cementation exponent:

$$m_{syst} = \frac{\ln\left(\frac{\phi_{sec}}{1 - 0.74\phi_t}\right)}{\ln(\phi_t)} \quad (19)$$

System formation factor

$$F_{syst} = \phi_t^{-m_{syst}} \quad (20)$$

System permeability

In some zones where it was completed the well and is know the system permeability of the zone by well test analysis and the system cementation exponent that involves the intensity of fracturing:

$$k_{fb} = A \phi_t^{m_{syst}} \quad (21)$$

System formation compressibility

The compressibility of total the porous volume is expressed in terms of its reduction with the pressure:

$$c_{fsyst} = \frac{-1}{V_{pt}} \frac{dV_{pt}}{dp} = \frac{-1}{\phi_t} \frac{d\phi_t}{dp} \quad (22)$$

where:

V_{pt} = total porous volume, L³.

P = net pressure, PSI.

V_b = total volume of rock, porous volume more volume of solids, L³

ϕ_t = total porosity, fraction.

System water saturation

$$S_{w\,sist} = \left(\frac{R_{\,sist}}{F_{\,sist} R_w} \right)^{-1/n_{\,sist}} = (I_{\,sist})^{-1/n_{\,sist}} \quad (23)$$

System saturation exponent

$$n_{\,sist} = \frac{\ln(fS_{w\,sist} + [1-f]S_{w\,ma}^{n_{\,ma}})}{\ln(S_{w\,sist})} \quad (24)$$

Matrix permeability and residual water saturation

The data of the permeability were collected to 3000 psi. The solid line continuous line of tendency is the one that better adjusts and it is in **Fig. 17**.

$$S_{wr} = 1.35k_{ma}^{-0.44} \quad (25)$$

Figure 17. Show that the water residual saturation is a strong function of the permeability in the low region of the permeability and gets to be almost independent from permeability when the permeability becomes above of 30 mD more or less.

The low permeability means generally that the throat radius pore on the rock is small and the capillary pressure is high. Therefore, the residual saturation of the water is high.

Similar relation between the saturation of the water and the permeability was observed by Timur (1968) for the sandstones rock samples that demonstrated a linear diminution of the logarithmic permeability with the increase of the residual saturation of the water.

Matrix saturation exponent and residual water saturation

Residual the water saturation against exponent of the saturation is in **Figure 21**.

$$S_{wr} = 0.0872n_{ma}^{1.1706} \quad (26)$$

Qualitatively, a higher exponent of the saturation in a level of the saturation of the brine means the great index of the resistance. A greater index of the resistance implies generally that the channels of the conduction (for the liquid and the electricity) are narrow and winding so that the residual saturation of the water is higher due to capillary effect.

The data of the saturation of the residual water obtained with the measures of capillary pressures could be used to consider the exponent of the saturation from which the level of the saturation of the brine can be derived thorough more for the interpretations of the resistance logs. Such estimation, nevertheless, can only be qualitative due to the great dispersion in the data demonstrated in **Figure 13**.

Matrix Permeability, Porosity, Residual Water Saturation

Through the best adjustment of correlations, a similar relation for rocks was derived from carbonate

$$k_{ma} = 15.613 \frac{\phi_{ma}^{2m_{ma}}}{S_{wr}^{2.053}} \quad (27)$$

This equation indicates that once the porosity and the permeability of the matrix are known, the residual saturation of the water can be considered.

$$S_{wr} = \left(\frac{\sqrt{k_{ma}}}{15.613 \phi_{ma}^{m_{ma}}} \right) \quad (28)$$

If the porosity and the residual saturation of the water are known, the permeability can be calculated for rocks of the deposit, the permeabilities calculated against the permeabilities measured in the samples of the carbonate rock. To see in **Figure 14**.

The Sonic Speeds and Porosity of matrix

The speeds of compression and shears are employees in the porosity of the matrix of the rock, that is the base of the sound recording. Wyllie et al. (1958) they developed to an equation supposed time-means, to derive porosity from the speed of compression of the formation.

The time average separates the liquid of the pore of the rock of the matrix (grain solids) and the adjustments of them in series. This simple adjustment of the liquid of the pore and the matrix of the rock of course is not applied to the liquid losses speed of the speed and it often does not render intolerable errors in the derived porosity.

An alternative is to correlate the speeds to the porosity for rocks with similar litología. The solid line continuous lines of trenches are those that better adjust to the measured data and they are in **Figures 15 and 16**

For carbonated rocks gas-saturated

$$V_p = 6.1143 - 8.9029\phi_m \quad (29)$$

$$V_s = 3.2951 - 5.2147\phi_m \quad (30)$$

For saturated oil rocks

$$V_p = 6.6248 - 10.3482\phi_m \quad (31)$$

$$V_s = 3.3378 - 5.3726\phi_m \quad (32)$$

where:

$$V_p = \text{speed of compression in (Km/s)}$$

$$V_s = \text{speed of shears in (Km/s)}$$

$$\phi_{ma} = \text{matrix porosity, in fraction}$$

These equations can be only used with the caution

that the uncertainty can be high in the derivation of the matrix porosity.

The Sonic Speeds and the Factor of the formation

The speeds of compression and shears are employees of the porosity of the matrix, must also be related to the factors of the formation. The sonic speeds in the gas-saturated samples of carbonate against factor of the formation in the same samples saturated with brine are in **Figure 17**.

$$V_p = 3.4825 F_{ma}^{0.0767} \quad (33)$$

$$V_s = 1.7552 F_{ma}^{0.0864} \quad (34)$$

Where better they imagine and, respectively. For the speeds on saturated oil rocks in the referring thing to the factors of the formation on same rocks saturated with brine, the similar relations exist are in **Figure 18**.

Where:

$$V_p = 3.6202 F_{ma}^{0.0823} \quad (35)$$

$$V_s = 1.7812 F_{ma}^{0.0852} \quad (36)$$

It is possible to be used to consider factors of the formation of sonic data of the speed, or vice versa in interpretations of the registry. Like the rest of the correlations, such estimations are again only qualitative because any exact derivation of a form of the parameter another one is impossible for rocks

CONCLUSIONS

The models of triple porosity represent better the flow of a rock fluid carbonated, until now only we have used models of double porosity, reason why the following step must be the study of the carbonate naturally fractured reservoir with a model that involves triple porosity.

The models allow the calculation of the porosity, the factor of the formation, the permeability of the porosity and the residual saturation of the water, and the exponent of the saturation of the residual saturation of the water, or vice versa.

The models are important and useful in the analysis of the logs for the carbonate naturally fractured reservoir. The residual water saturation measured in the laboratory and derivatives of the models are also useful in reservoir engineering.

The geophysical logs, core measurements and petrophysical characterization are important to calculate the petrophysical properties.

In this work demonstrates that the permeability from the formation factor can be calculated but the correlation is low.

The petrophysical characterization allows to obtain petrophysical properties of the secondary system.

The cementation exponent of the system is the most

important parameters for applying the petrophysical characterization.

With the petrophysical characterization is possible to build the 3D distribution of several properties for to build a numerical simulation model.

It is necessary to develop a model of petrophysical characterization of triple porosity with the purpose of increasing the precision of the permeability of the system (first, fractures and vugs) for each one of means.

Several tools of calibration confirm the mixed models.

NOMENCLATURE

a = constant

m = cementation exponent

n = saturation exponent

F_{ma} = factor of resistivity of the formation

k = permeability (mD)

I = resistivity index

R_o = resistivity of the rock totally saturated with brine (ohm-m)

R_t = resistivity of the brine to the saturation of S_w (ohm-m)

R_w = resistivity of the brine (ohm-m)

S_w = saturation of the brine (fraction)

S_{wr} = residual water saturation (fraction)

V_p = speed of compresional wave (Km/s)

V_s = speed of wave shears (Km/s)

ϕ = porosity (fraction)

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Appendix A. Mixing Model of Formation Compressibilities in Naturally Fractured Reservoirs (Pulido and Samaniego, 2005)

Total porosity is given by:

$$\phi_t = \phi_{ma} + \phi_{sec} \quad (A-1)$$

The derivative of total porosity with respect to net pressure:

$$\frac{d\phi_t}{dp} = \frac{d\phi_{ma}}{dp} + \frac{d\phi_{sec}}{dp} \quad (A-2)$$

Arranging the eq. A-2:

$$\frac{1}{\phi_t} \frac{d\phi_t}{dp} = \frac{\phi_{ma}}{\phi_t} \frac{1}{\phi_{ma}} \frac{d\phi_{ma}}{dp} + \frac{\phi_{sec}}{\phi_t} \frac{1}{\phi_{sec}} \frac{d\phi_{sec}}{dp} \quad (A-3)$$

The matrix formation compressibility

$$c_{fma} = \frac{1}{V_{pma}} \frac{dV_{pma}}{dp} = \frac{1}{\phi_{ma}} \frac{d\phi_{ma}}{dp} \quad (A-4)$$

The secondary system formation compressibility:

$$c_{fsec} = \frac{1}{V_{psec}} \frac{dV_{psec}}{dp} = \frac{1}{\phi_{sec}} \frac{d\phi_{sec}}{dp} \quad (A-5)$$

The system formation compressibility:

$$c_{fsyst} = \frac{1}{V_{pt}} \frac{dV_{pt}}{dp} = \frac{1}{\phi_t} \frac{d\phi_t}{dp} \quad (A-6)$$

Replacing the definitions of compressibility for each porous media and using the secondary volumetric fraction is obtained a Mixing Model

$$c_{fsyst} = [1 - f_v] c_{fma} + f_v c_{fsec} \quad (A-7)$$

The secondary formation compressibility is function of the compressibility del system, the matrix, and partition coefficient (secondary porosity and matrix porosity):

$$c_{fsec} = \frac{c_{fsyst} - [1 - f_v] c_{fma}}{f_v} \quad (A-5)$$

Example

To determine the formation compressibility of the secondary system with the following information

$$c_{fsyst} = 14 \times 10^{-6} \text{ psi}^{-1},$$

$$c_{fma} = 8 \times 10^{-6} \text{ psi}^{-1},$$

$$\phi_{ma} = 0.10$$

$$\phi_t = 0.12$$

Solution

The secondary volumetric fraction:

$$f_v = \frac{\phi_{sec}}{\phi_t} = \frac{0.12 - 0.10}{0.12} = 0.167$$

Replacing in the previous formula:

$$c_{fsec} = \frac{14 \times 10^{-6} - [1 - 0.167] 8 \times 10^{-6}}{0.167} = 43.93 \times 10^{-6} \text{ psi}^{-1}$$

The relation is:

$$\frac{c_{fsec}}{c_{fsyst}} = \frac{44}{14} = 3.1428$$

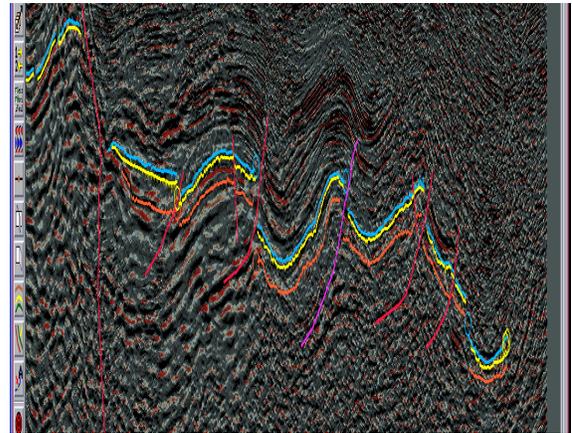


Fig. 1. Seismic Sections.

Sección estratigráfica inicial (sin análisis estructural)

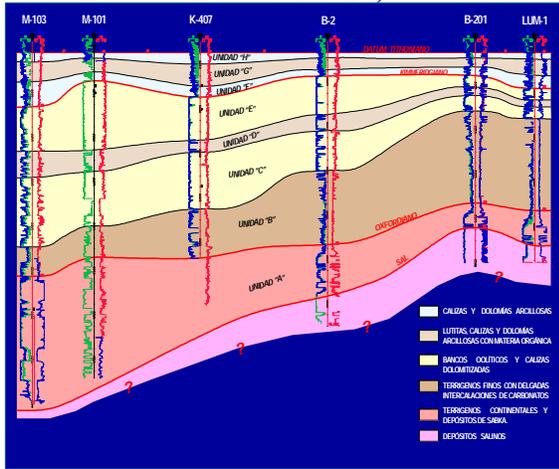


Fig. 2. Initial stratigraphic analysis without structural analysis.

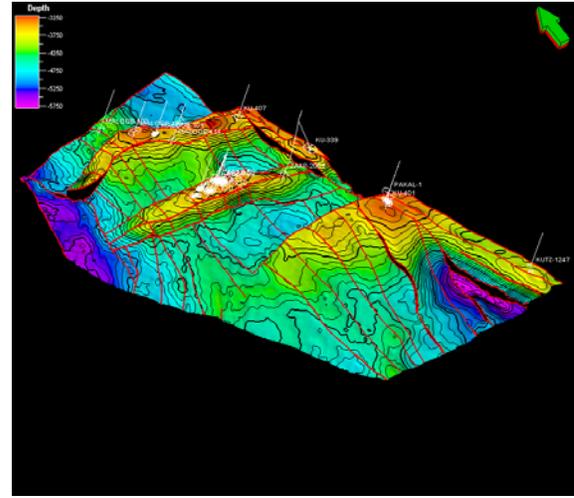


Fig. 5. Geological, structural and sedimentological framework.

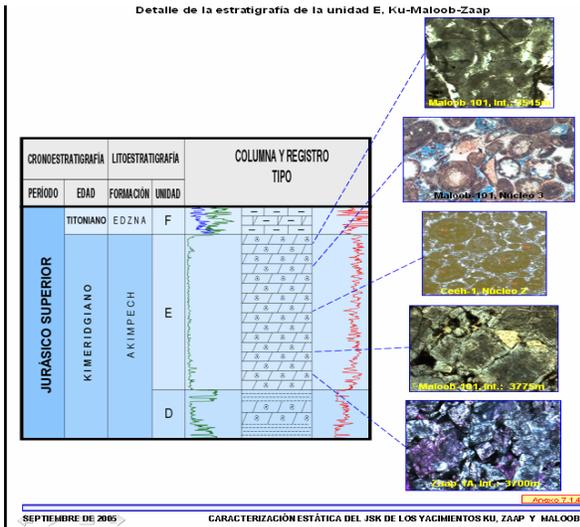


Fig. 3. Petrographic Analysis.

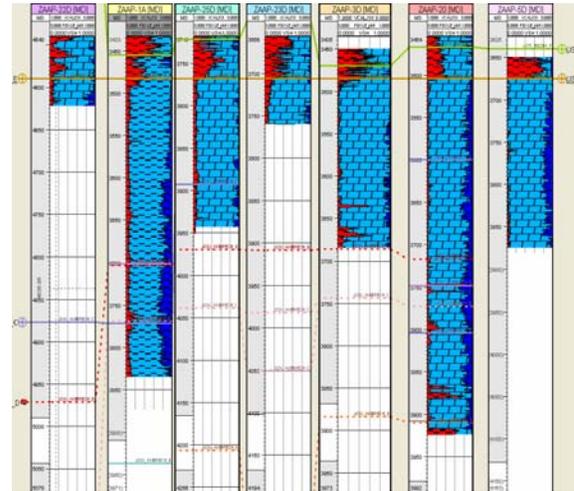


Fig. 6. Lithologic interpretation, KUJ formation.

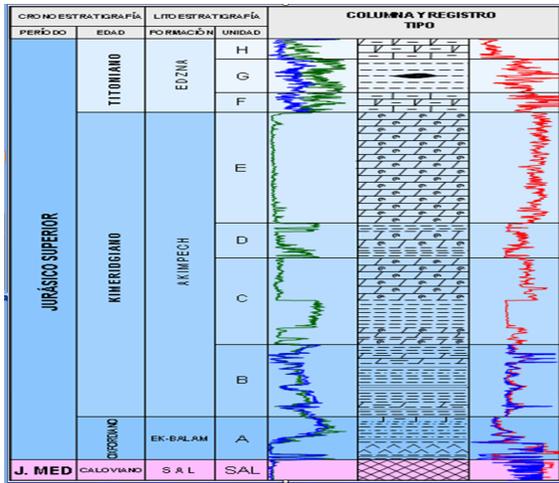


Fig. 4. Regional Type Logs.

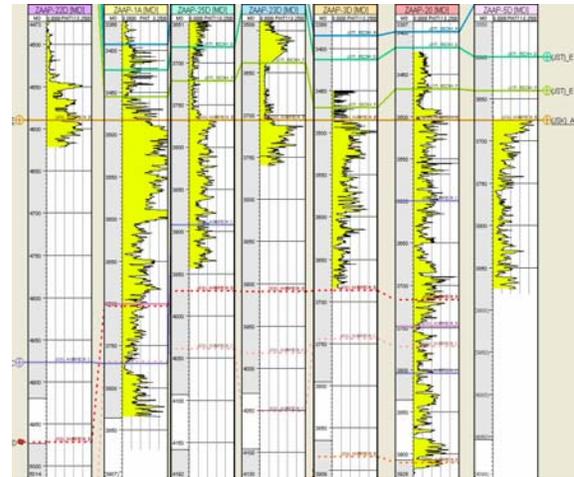


Fig. 7. Total porosities (KUJ).

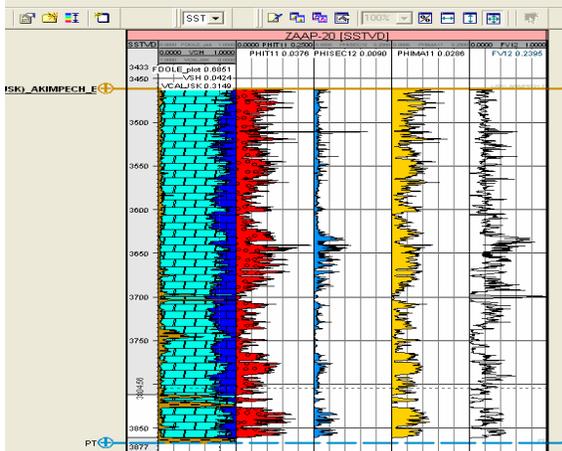


Fig. 8. Secondary Porosity.

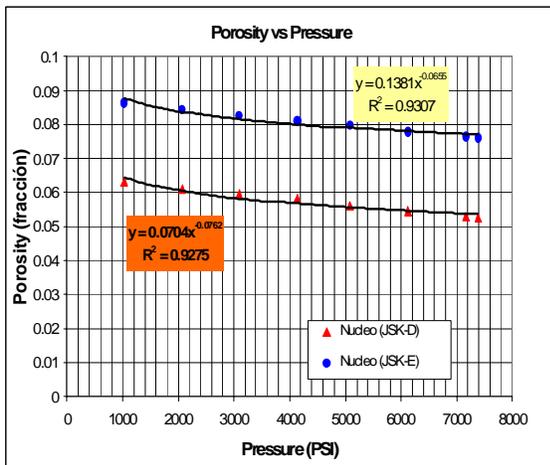


Fig. 9. The matrix porosity was measured as a function of the overload pressure.

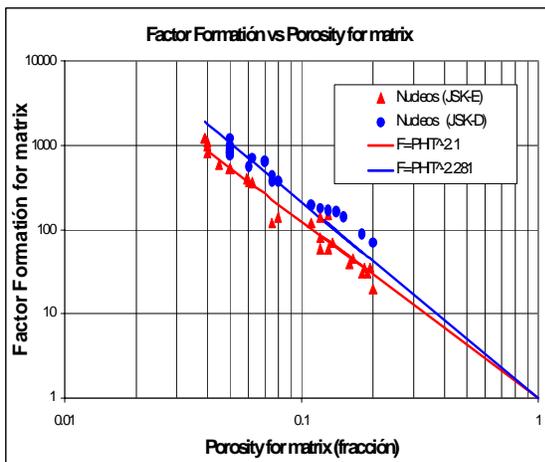


Fig. 10. Matrix formation factor versus matrix porosity for different lithostratigraphic units, the cementation exponent slightly varies.

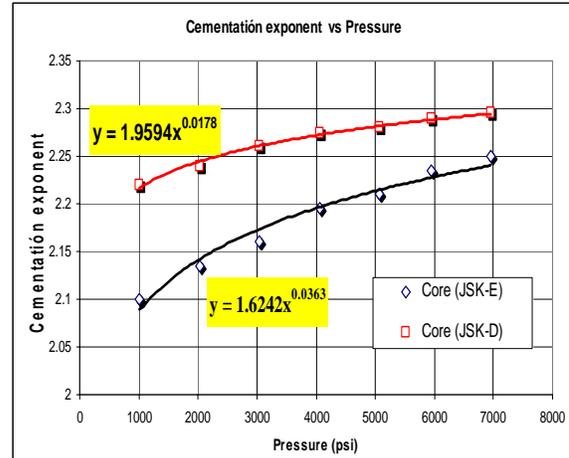


Fig. 11. Matrix cementation exponent as a function of the net pressure.

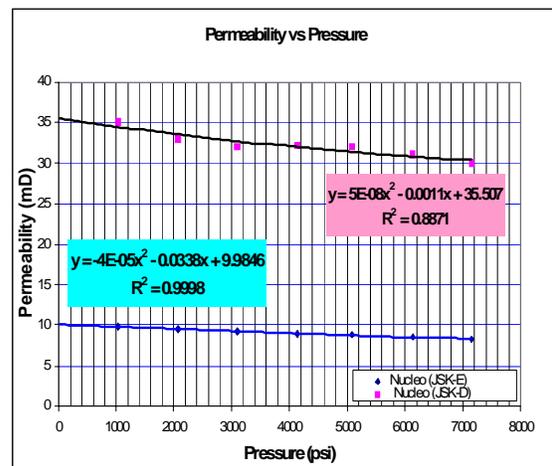


Fig. 12. The system permeability decrease with a pressure is caused by the gradual closing of the pores space (fractures, micro fractures, and matrix).

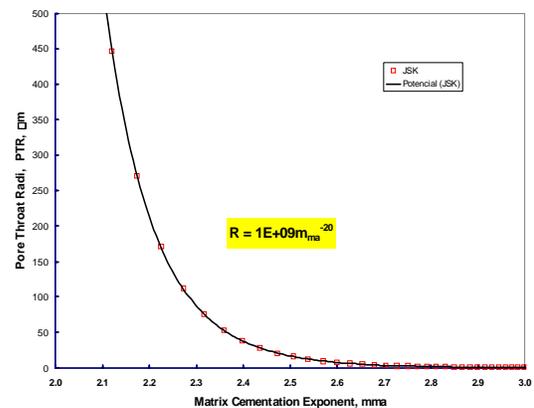


Fig. 13. Matrix cementation exponent was obtained as a function of the pore throat radius.

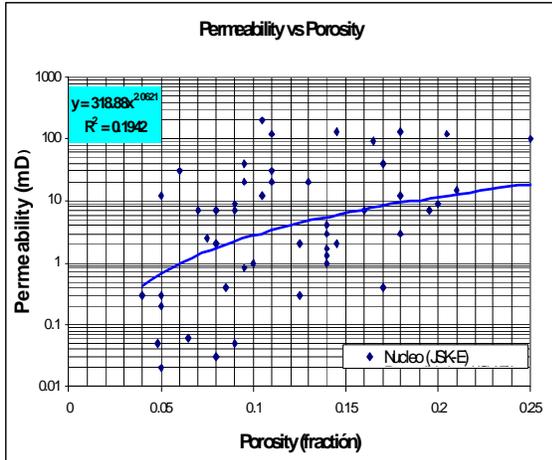


Fig. 14. The relation between the matrix porosity and the permeability of is possible, if the radius of pore throat is used.

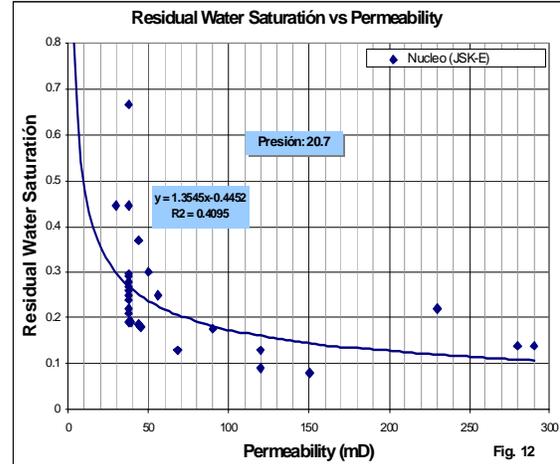


Fig. 17. Residual water saturation is for low values a strong function of permeability, and as it increase above 30 mD this dependence decreases.

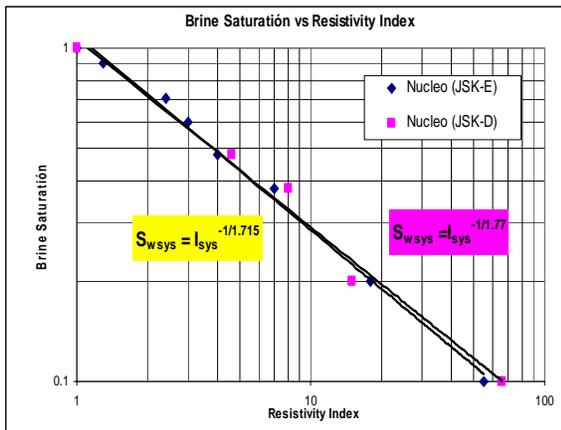


Fig. 15. The brine saturation vs. resistivity index.

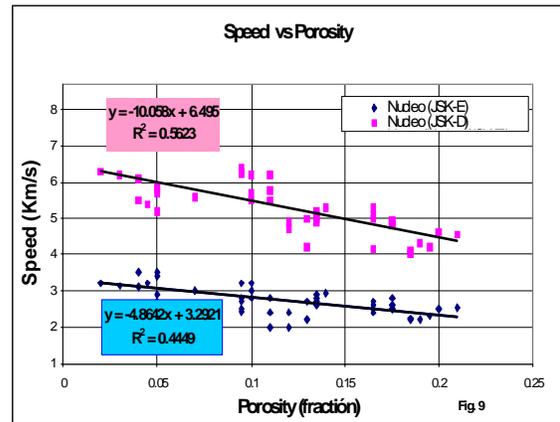


Fig. 18. Sonic speeds, compression speed V_p versus the shear speed, V_s , were saturated with an gas.

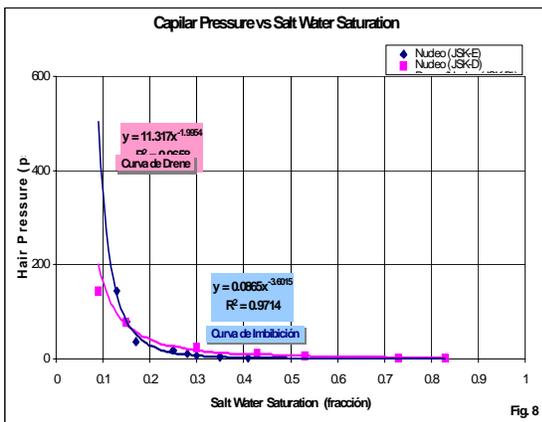


Fig. 16. The gas-water capillary pressures were measured in cores.

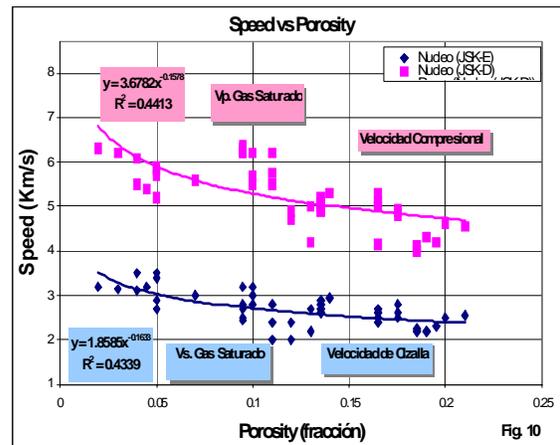


Fig. 19. The same speeds were measured when the cores were saturated with an oil of 25° API.

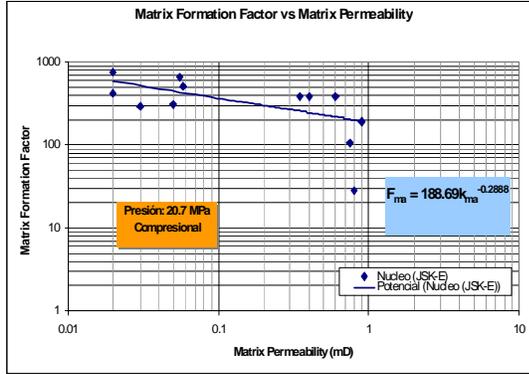


Fig. 20. The matrix formation factor vs. matrix permeability.

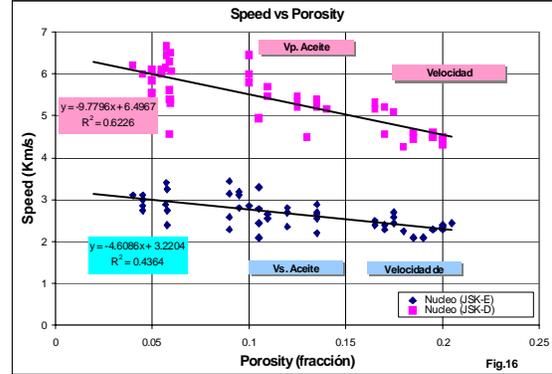


Fig. 23. The speeds of compression and shears are employees of the matrix porosity, that is the base of the sound logs.

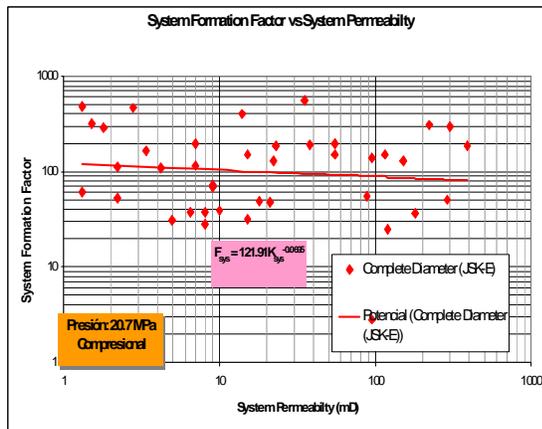


Fig. 21. System formation factor of vs System permeability.

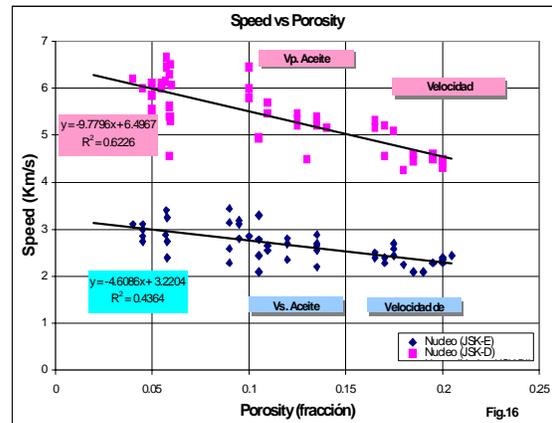


Fig. 24. The Sonic speeds (compression and shear) with the Factor of the formation (saturated with brine).

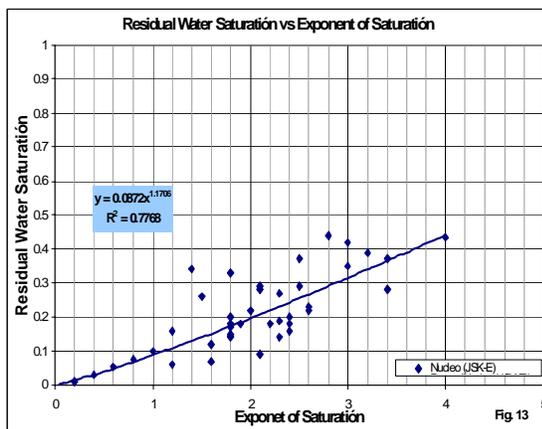


Fig. 22. Residual Water Saturation vs Saturation Exponent.

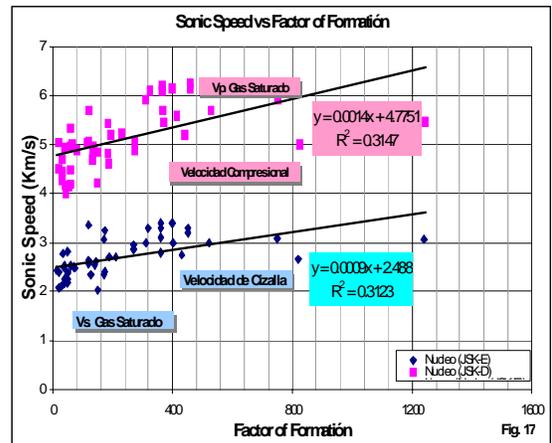


Fig. 25. The Sonic speeds (compression and shear) with the Factor of the formation (saturated with oil).

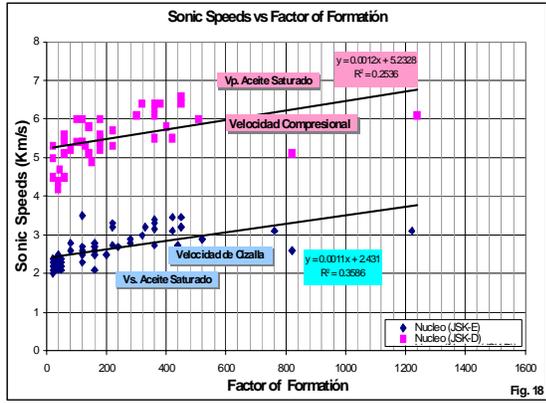


Fig. 26. Sonic Speed vs Formation of Factor.

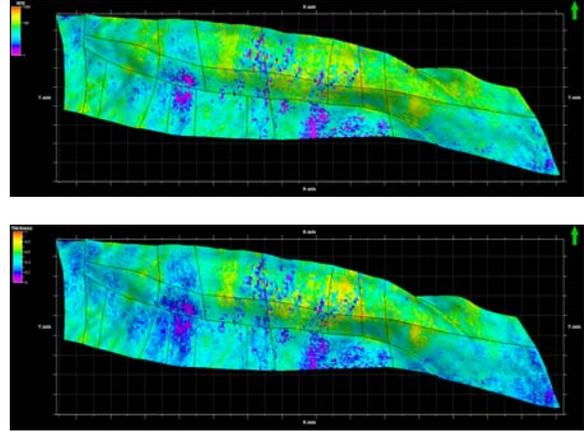


Fig. 29. System Permeability and Fracture average width.

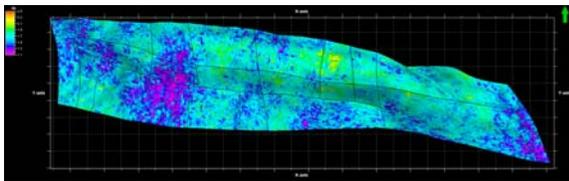


Fig. 27. Total porosity and System cementation exponent.

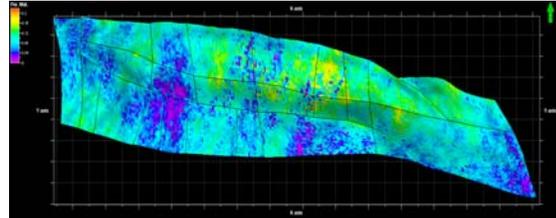
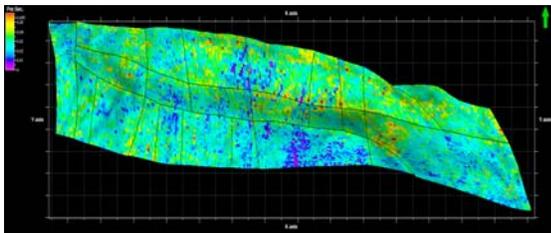


Fig. 28. Secondary Porosity y Matrix Porosity