Pore pressure prediction in carbonates using pore and matrix compressibilities

Juan Pedro Morales Salazar
jp.morales.salazar@comunidad.unam.mx
Facultad de Ingeniería
Universidad Nacional Autónoma de México.

Rubén Nicolás López
rnlopez@imp.mx

Mario Gerardo García Herrera
ggarcia@imp.mx
Instituto Mexicano del Petróleo

Fernando Samaniego Verduzco
pexfsamaniegov01@pemex.com
Facultad de Ingeniería
Universidad Nacional Autónoma de México

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Abstract

It is of great importance to obtain high quality pore fluid pressure information in order to succeed in drilling tasks and also to perform an accurate reservoir simulation.

The main objective of the pore pressure method is to make a comparison between a normal trend with measured data, from the sonic log, formation resistivity or d-exponent. Shale formations show direct responses on porosity and pore pressure as a function of burial; therefore most of the methods are based on shale. However, carbonates have a different sedimentary origin; they are rigid and might not show response on porosity and over pressure at the same time.

This work involves the theory of a pore pressure prediction method for carbonate reservoirs developed by Atashbari et al (2012). The method to calculate the effective stress was developed by using compressibility attributes of reservoir and formation rocks (Method of pore-and-rock compressibilites). In the case of under compaction, pore pressure depends on the change of pore space within the rock, which is a function of rock (matrix) and pore compressibilities as well as of bulk compressibility.

An improved solution for the pore pressure prediction method in carbonates is the main objective of this work. Brief flow diagram that would allow the easy application of this method in carbonate formations is presented. Additionally, three applications of the method in carbonate formations from Mexico are shown.

Keywords: Pore pressure, carbonates, compressibilities of pore and matrix.

Predicción de la presión de poro en carbonatos a partir de las compresibilidades del poro y la matriz

Resumen

Es de gran importancia obtener dato de gran calidad referentes a la presión de poro, con el objetivo de alcanzar el éxito en las tareas de perforación, así como para realizar una simulación de yacimientos más exacta.

La mayoría de los métodos de presión de poro realizan una comparación entre una tendencia normal y con medidos del registro sónico, registro de resistividad o del exponente d. Las formaciones de lutita muestran una respuesta directa en la porosidad y la presión de poro en función de la profundidad; la mayoría de los métodos para predicción de presión de poro están basados en el comportamiento de las lutitas. Sin embargo, los carbonatos presentan un origen sedimentario totalmente diferente; son rígidos y pueden no presentar respuesta en porosidad, pero sí sobrepresión.

Este trabajo está basado y presenta algunos resultados de una tesis de Maestría presentada en la Universidad Nacional Autónoma de México, (UNAM). Este trabajo trata la teoría del nuevo método para la predicción de poro en carbonatos desarrollado por Vahid Atashbari et al., publicado por la Sociedad de Ingenieros Petroleros (SPE por sus siglas en Inglés). El nuevo método para el cálculo del esfuerzo efectivo se obtuvo utilizando datos de las compresibilidades del yacimiento y de las formaciones rocosas. En el caso de bajo compactación, la presión de poro depende del cambio del espacio poroso.

De igual manera se presenta una solución propuesta al nuevo método para la predicción de la presión de poro. Adicionalmente, se muestran tres aplicaciones del nuevo método en formaciones de carbonatos en México.

Palabras clave: Predicción de la presión de poro en carbonatos, compresibilidades del poro y de la matriz.

Introduction

Nowadays there is a variety of specialized software in the market focused to predict the pore pressure in shale formations, Nicolás-López et al. (2012), but flaw predicting pore pressure in carbonate rocks. An alternative to solve this problem is the method of pore pressure prediction developed by Atashbari et al. (2012).

Atashbari et al, (2012) list the mechanisms of pore pressure generation as follows:

1) Loading
2) Hydrology
3) Clay diagenesis
4) Tectonics
5) Other chemical reactions
6) Kerogen transformation
7) Osmosis

The objective of this work is to apply the method of Atashbari et al, (2012), in order to predict the pore pressure for different wells from Mexico, wells drilled in carbonate formations, through a proposed solution which results as an improvement of Atashbari's method.

Pore pressure prediction method for carbonate formations

In this section, it is stated the compressibilites method developed by Atashbari et al, (2012).

Atashbari et al, (2012) started the analysis with simple definitions of pore-and-rock compressibilities. Zimmerman (1991), introduced four types of compressibility for two independent volumes and pressures. The first subscript of indicates the volume change; the second subscript indicates the varying pressure.

$$c_{bc} = -\frac{1}{V_b{}^i}\left[\frac{\partial V_b}{\partial P_c}\right]_{P_p}, \qquad (1)$$

$$c_{bp} = -\frac{1}{V_b{}^i}\left[\frac{\partial V_b}{\partial P_p}\right]_{P_c}, \qquad (2)$$

$$c_{pc} = -\frac{1}{V_p{}^i}\left[\frac{\partial V_p}{\partial P_c}\right]_{P_p}, \qquad (3)$$

$$c_{pp} = -\frac{1}{V_p{}^i}\left[\frac{\partial V_p}{\partial P_p}\right]_{P_c}. \qquad (4)$$

The subscript *i* refers to the initial state of the rock (before compression), *b* and *p* express bulk (the entire system) and pore respectively. Getting ∂V_b from equations (1) and (2) and combining them together, gives us the following relation:

$$\partial P_p = \frac{c_{bc}}{c_{bp}}\partial P_c. \qquad (5)$$

Based on Zimmerman (1991) theory, we can assume infinitesimally small and equal sized increments of all independent variables (confining pressure and pore pressure), it results:

$$dP_p = \frac{c_{bc}}{c_{bp}}dP_c. \qquad (6)$$

Equation (6) sates that the change in pore pressure is directly proportional to the change in confining pressure times the compressibilities ratio.

Bulk and pore compressibilities are known from special core analysis (SCAL), but since in the test the pore pressure is constant, bulk compressibility is unknown. To overcome this issue, the relation that involves bulk compressibility due to confining and pore pressure demonstrated by Zimmerman (1991), is used as follows:

$$c_{bp} = c_{bc} - c_r. \qquad (7)$$

Then the matrix compressibility definition demonstrated by Van Golf-Racht (1982) is used:

$$c_r = \frac{\phi}{1-\phi}c_{pc}. \qquad (8)$$

Substituting equation (8) into equation (7), the next expression is obtained.

$$c_{bp} = c_{bc} - \frac{\phi}{1-\phi}c_{pc}. \qquad (9)$$

The use of equation (9) in equation (6) allows the derivation of a pressure differential which is applied to the porous media as function of bulk compressibility due to change on confining pressure and pore compressibility due to change in confining pressure too.

$$dP_p = \frac{c_{bc}}{c_{bc} - \frac{\phi}{1-\phi} c_{pc}} dP_c. \tag{10}$$

Taking $(1 - \phi)$ as common factor, gives as a result Eq. 11:

$$dP_p = \frac{c_{bc}}{\frac{(1-\phi)c_{bc} - \phi c_{pc}}{(1-\phi)}} dP_c. \tag{11}$$

Simplifying equation (11), the pressure differential is defined which is linked to the porous media as a function of bulk and pore compressibilites times the change inconfining pressure.

$$dP_p = \frac{(1-\phi)c_{bc}}{(1-\phi)c_{bc} - \phi c_{pc}} dP_c. \tag{12}$$

Integrating equation (12) and adding an exponential constant in order to correlate and calibrate it to different geological carbonate formations, an equation to predict the pore pressure in carbonate formations using the compressibilities is derived.

$$P_p = \left(\frac{(1-\phi)c_b}{(1-\phi)c_b - \phi c_p} \sigma_{effective} \right)^{\gamma}. \tag{13}$$

If data concerning core tests (SCAL) is available, equation (12) can be solved to obtain formation porosity. Accordingly, equation of normal porosity presents the next form:

$$\phi = \frac{c_{bc} dP_p - c_{bc} dP_c}{c_{pc} dP_p + c_{bc} dP_p - c_{bc} dP_c}. \tag{14}$$

Atashbari et al., (2012) proposed a range of values for the empirical constant gamma (γ) in Eq. (13), varying from 0.9 to 1 (when using psi as unit of pressure and stress). However in this work, it was defined a range for carbonate formations of México, ranging from 0.8 to 0.9 (using kg/cm^2 as unit of pressure and stress). It is important to clarify that the new range was developed by using the method improved in the present paper for the pore pressure prediction with the three wells presented; however, it is important to apply the method in more and distinct locations in Mexico in order to corroborate or redefine the proposed range for the γ constant.

Solution to the pore pressure prediction method in carbonates: a proposal

Atashbaris's et al. (2012) pore pressure prediction method in carbonate reservoirs and formations presents a weakness, the lack of available information. To the best application of the method, we might be capable of having sufficient economic and technical resources in order to obtain or perform special core analysis to estimate the needed pore pressure in carbonate formations.

In fact, when an oil company is going to perform an exploration project or even field development, the resources (technical and economic) are limited, and these constraints become greater when weak economic conditions prevail in the oil and gas industry worldwide.

Consequently, the need of finding a solution to the lack of sufficient information and/or resources is of great importance.

Proposed solution

To succeed these problems that result of applying the new method of pore pressure prediction, the use of two definitions demonstrated by Van Golf-Racht (1982) was proposed.

This proposal (Morales-Salazar, 2014), came up as an easy way to overcome the absence of information. The minimum required data are well logs, especially bulk density log (RHOB) and density porosity log (DPHI), and some knowledge about the lithology to be drilled (depths at which carbonate formations are located) and minerals present in the rock matrix (calcite, dolomite, siderite, etc).

To apply equation (13) we need to determine the bulk compressibility and pore compressibility, which remain unknown until we perform special core analysis of the carbonate formation we are interested in. Thus, the next definitions discussed by Van Golf-Racht are assumed to be valid:

$$c_b = (1-\phi)c_r, \qquad (15)$$

$$c_p = \frac{(1-\phi)}{\phi}c_r. \qquad (16)$$

Assuming absence of horizontal compaction there will be no deformation; hence, the compressibility of the pore space can be written as:

$$c_p = \frac{1}{2}\frac{(1-\phi)}{\phi}c_r. \qquad (17)$$

To apply equations (15) to (17), the density porosity log (DPHI) is used; it is important to know or to have certain knowledge related to matrix mineralogy. It can be seen that the rock compressibility remains unknown; therefore, in order to obtain the rock matrix compressibility (C_r), we have to be capable of estimating a bulk modulus of the rock matrix (K_r) which could be directly related to the main or greatest carbonate mineral fraction within the rock matrix. Finally we get the matrix compressibility of the rock as follows:

$$c_r = \frac{1}{K_r}. \qquad (18)$$

While assuming the value of the bulk modulus of the rock matrix (K_r), petrology charts, log interpretation charts or data from literature with established and proved values can be used.

Morales-Salazar (2014) demonstrated that by assuming one mineral in the matrix gives acceptable results (the assumed mineral has to be the main constituent of the matrix). It is important to point out that making a log inversion to obtain mineral fractions in the rock matrix is a better approach than Eq. (18). Unfortunately, the latter approach described is out of the scope of this work.

Flow diagram for applying the new pore pressure prediction method in carbonates

To apply the method of this paper, we developed a flow diagram in order to make easier the procedure involved in this method and with the specific objective of giving a completely new tool to the petroleum engineers worldwide that are involved in drilling design tasks, like casing seat and the operative window design.

Figure 1 presents a flow diagram for the theory of this work.

As input parameters in Figure (1), there are the normal pore pressure equal to a hydrostatic column of connate water, the vertical stress equal to the lithostatic weight over the carbonate reservoir and porosity equal to the density porosity log (DPHI).

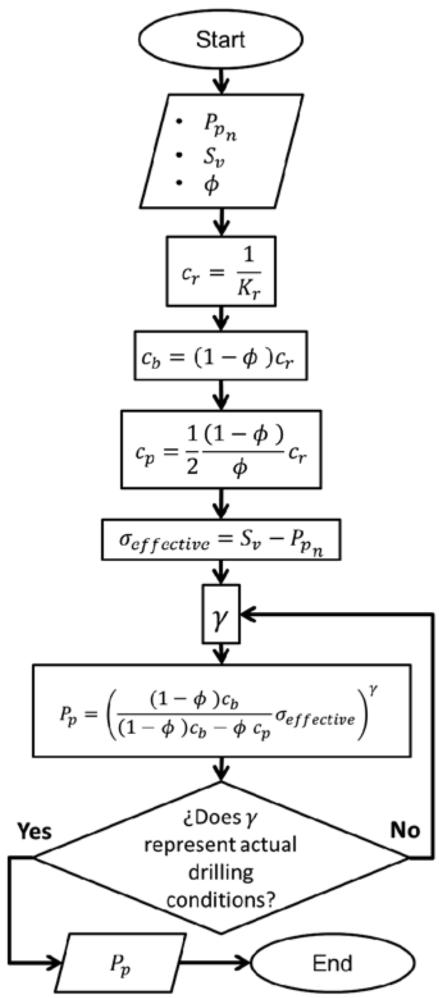

Figura 1. Flow diagram of the present pressure prediction method in carbonate formations. Knowing the main carbonate mineral fraction in the rock matrix, the bulk modulus value of that mineral has to be estimated from a known reference.

After it, comes the calculation of bulk compressibility. The pore compressibility can be obtained from two different equations. In the Figure 1 only equation (17) is shown regarding pore compressibility, because it behaved better during the calculations.

The calculation of the effective stress comes next; it is only a subtraction of the vertical stress minus the normal pore pressure, which is equivalent to a hydraulic head of a connate water column at a given depth.

Finally comes equation (13), it is the equation used to calculate of pore pressure prediction in carbonate reservoirs.

Calibration of the exponent gamma (γ) might be done by a trial and error procedure. Data from day-to-day drilling, reported events such as gasification or influx into the well and mud weight can be used.

Application of the new pore pressure prediction method in wells from Mexico

To elaborate the present work, the data of three different wells form Mexico were available; the first example is an onshore well located in the Burgos basin in the northern part of Mexico.

Example two and three correspond to offshore wells located in the Gulf of Mexico, near Ciudad del Carmen in Campeche, México.

All the calculations were done following the Figure (1). To compute the Vertical Stress the density log was used (RHOB), the used porosity log which gave better results with the available calibration data was the density-porosity log (DPHI). The logs implemented in every case as input data were the same.

Example one: Well A, onshore well from Burgos basin

Drilling of well A started on April 19th 2013 and was finished on May 21st 2013, the total depth of this well is 2830 [m] true vertical depth. It is located 124 [km] 86°44´04.27´´ SW from Reynosa, Tamaulipas, **Figure 2**.

Its objective was to incorporate reserves and test the oil potential of the Pimienta formation, (Upper Jurassic).

Figure 2. Location of well A, (taken from Google Maps, 2018).

After trial-and-error and from the readings of the litho-density tool, especially readings in the bulk density log (RHOB); it was assumed a matrix of dolomite in carbonate zones. Therefore the value of the bulk modulus to compute the matrix compressibility was obtained from Mavko et al. (2009):

$$K_r = 94.9\ [GPa]$$

With data from the gamma ray log and knowledge of the geology of the well area, the top of the carbonate zone was set around 1700 [m] true-vertical depth; this depth was used in the following calculations.

Figure 3 shows that Eaton's method fits just right to the mud weight in shale formations, that correspond to depths lower than 1500 [m] approximately. Immediately the pore pressure profile shows a decreasing behaviour, due to transition from shale formations to carbonates. It means that Eaton´s method cannot be used for carbonate.

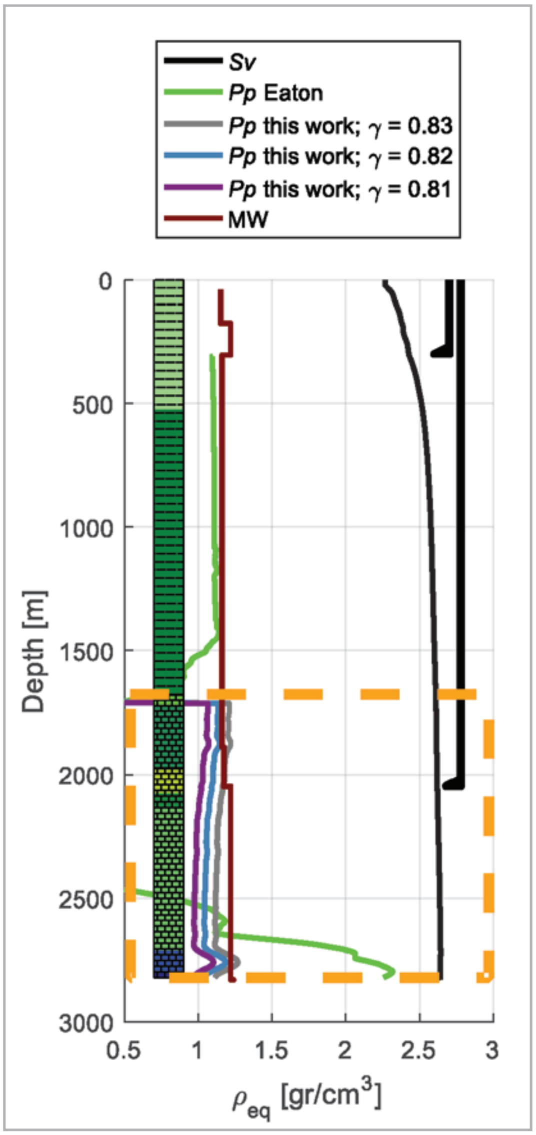

Figure 3. Comparison among Eaton's method and the method of this paper in well A.

In Figure 3 and in upcoming figures, the geological column can be appreciated to the left of the figure; the casing seats are located to right. The black line represents the vertical stress. The *x* axis corresponds to equivalent density (gradient) and the *y* axis corresponds with depth in meters.

The green line represents Eaton's method, results lines purple, blue and gray represents the method of pore pressure prediction in carbonate formations for different values of the calibration exponent gamma; the mud weight used to drill well A is represented by the maroon line, (the mud weight was the calibration parameter of the pore pressure profile). Carbonate zone are inside the pointed orange line rectangle.

At a depth of 1700 [m] the method of this paper, shows a response at the top of the carbonates. The grey line corresponds to a gamma equal to 0.81, the blue line corresponds to a gamma equal to 0.82 and the purple correspond to a gamma equal to 0.83. The profile best fits the mud weight is the blue line, with gamma equal to 0.82.

Even though the Pimienta formation can be described as calcareous shale, the modified Atashbari's method of this paper shows better results than Eaton's method in this zone (from 2713 [m] to 2797 [m] true vertical depth), this is the reason why the improved Atashbari's method was taken to represent this formation.

Figure 4 presents a mixed pore pressure profile formed by the profile generated with Eaton's method, for the upper formations (depths lower than 1700 [m]) and the pore pressure profile calculated with the current method (gamma equal to 0.82), for carbonate formations with depth from 1700 [m] to the bottom of the well.

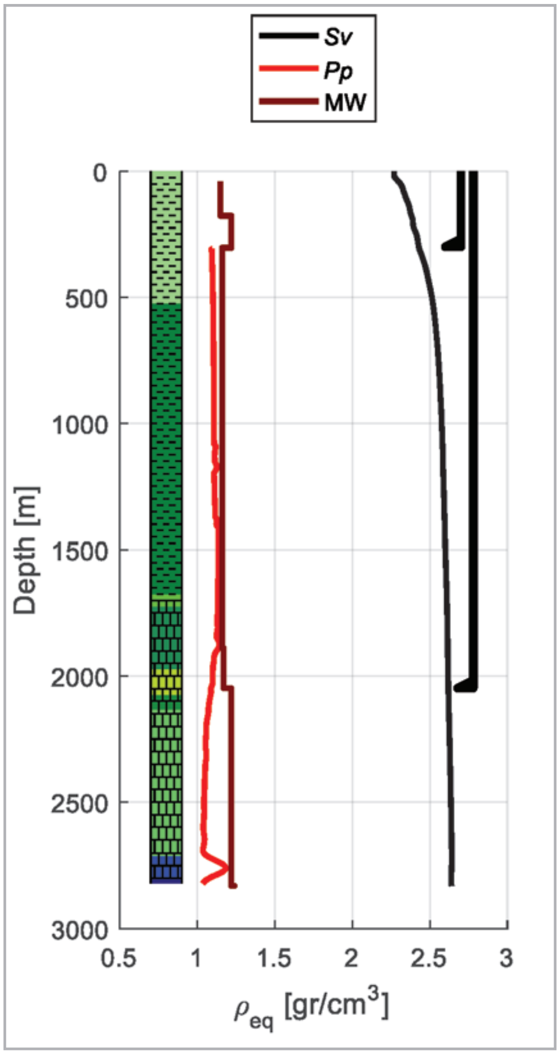

Figure 4. Complete pore pressure profile of well A.

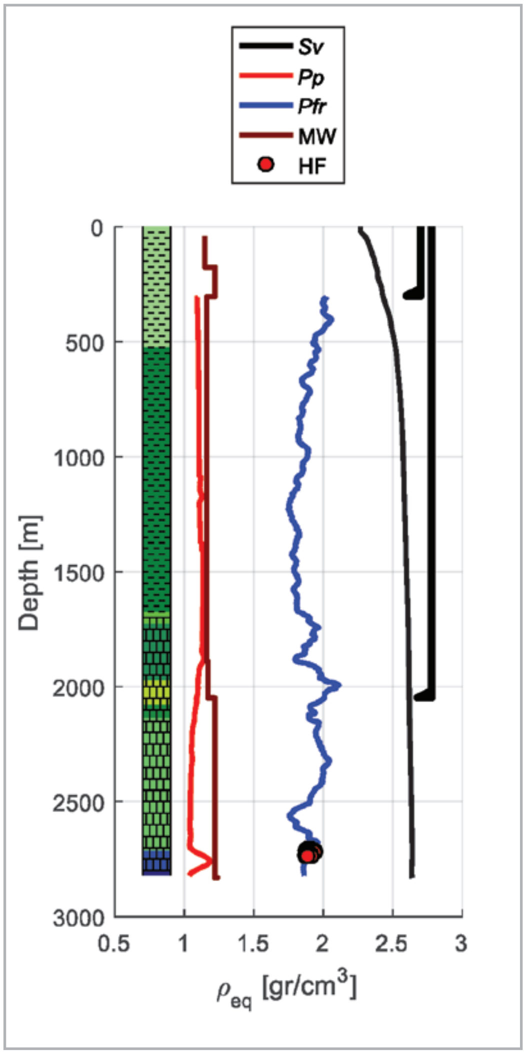

Figure 5. Operative window of well A.

To attain the operative window, the fracture pressure gradient must be calculated and calibrated with the method that better fits the conditions of the area.

Finally, **Figure 5** presents the operative window of well A where the vertical stress gradient is represented by the line in black; pore pressure gradient is represented by the red line, the blue line corresponds to the fracture pressure gradient, the maroon line represents the mud weight and the red circles illustrate mini-frack tests that functioned as calibration data for fracture pressure gradient.

Example two: Well B, offshore shallow water well

As stated, examples two and three correspond to offshore wells, both located in the Gulf of Mexico. **Figure 6** shows that well B is 143.15 [km] NW from Ciudad del Carmen, Campeche in the Gulf of Mexico. The well C is located 14.5 [km] NE form well B. The mud line of well B is located 178 [m] depth.

Figure 7 shows a comparison between Eaton's, Bower's and this work's method. From Figure 7 it can be observed that Eaton's method and Bower's offer good fitting in Tertiary shale formations, (depths lower than 2300 [m]).

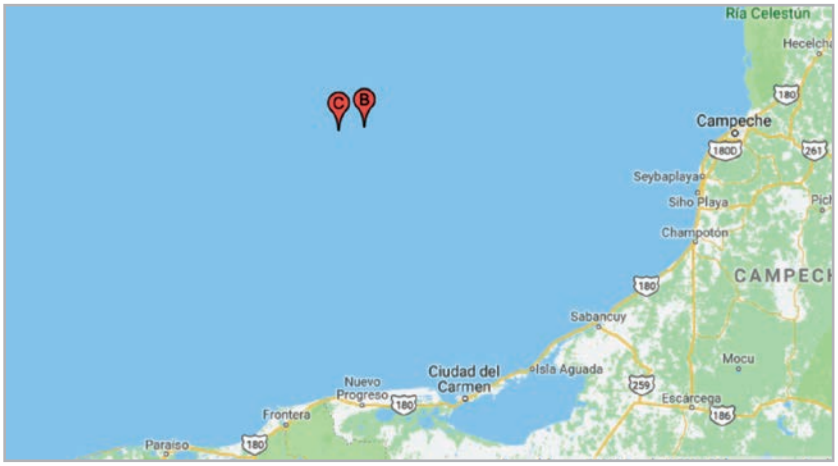

Figure 6. Locations of Wells B and C (taken from Google Maps, 2018).

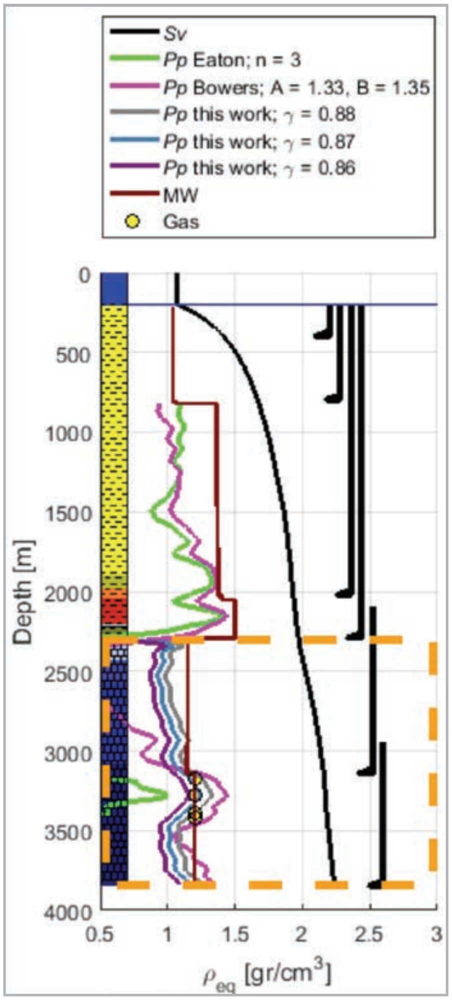

Figure 7. Comparison among different pore pressure prediction methods in well B.

In Cretaceous and Jurassic carbonate formations (depths greater than 2300 [m]), the modified method of Atashbari et al. (2012), provides acceptable behaviour compared with the calibration yellow circles (gas presence during well B drilling). The pore pressure profile that best fits these points is this work's method, with gamma equal to 0.87. Although Bower's method profile show a response in the same area where gas took place, it wasn't able to match Bower's method to the field gas influx. For calculation of carbonate pore pressure prediction method, a matrix of dolomite was assumed, (Morales-Salazar, 2014).

Figure 8 show the final mixed pore pressure profile of well B, formed by Eaton' method form the top to 1275 [m] depth, Bower's method from 1275 [m] to 2296 [m] depth and the improved Atashbari's method of the present paper from 2374 [m] to the bottom of the well.

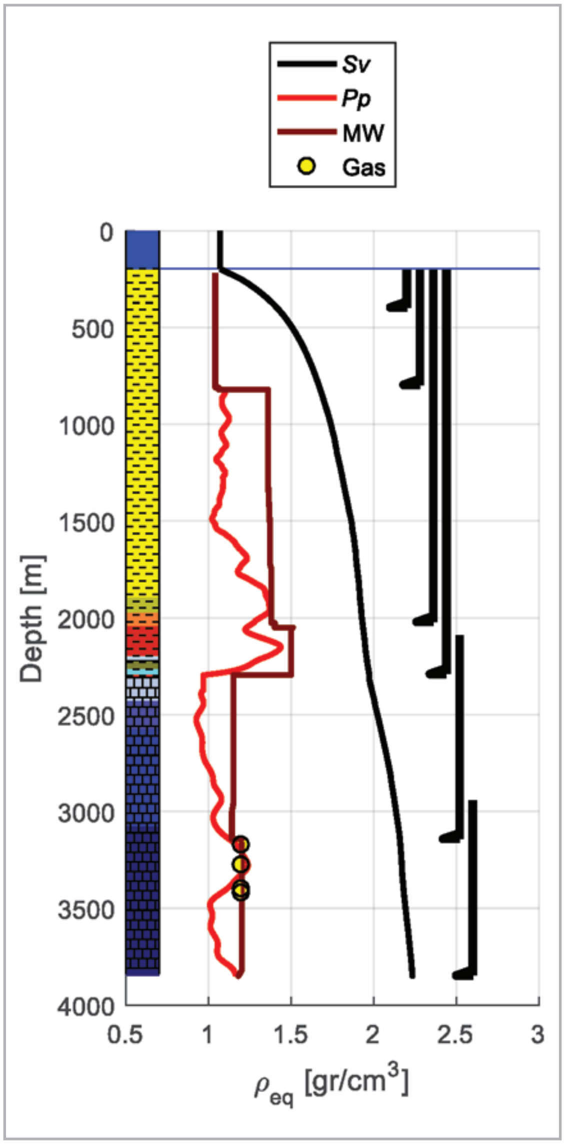

Figure 8. Complete pore pressure profile of well B.

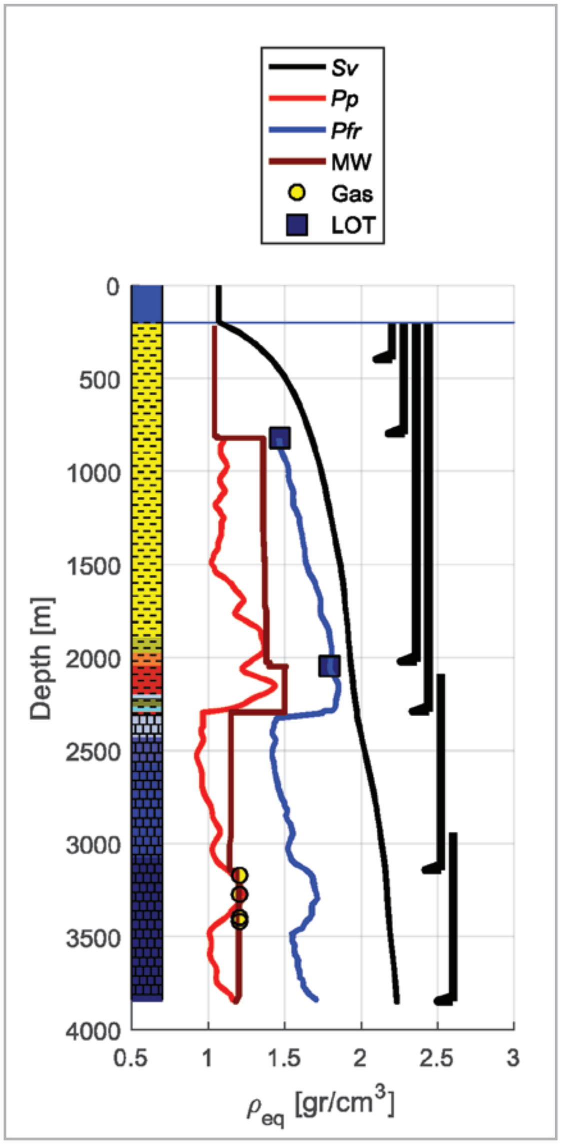

Figure 9. Operative window of well B.

It can be appreciated in **Figure 9** that the fracture pressure gradient profile (blue line) was considered in order to complete the drilling operative window of Well B. This fracture pressure was calibrated with leak off tests (LOT) represented by navy squares.

Example three: Well C, offshore deep water well

The last example corresponds to Well C; its location was given by Figure 6.

It is important to state that even though the maximum depth of Well C is 4050 [m] of true vertical depth, logs we had access to present a final depth of 3788 [m]. Mud line of well C is located 706 [m] depth.

Figure 10 shows results of different pore pressure prediction methods applied using data of well C.

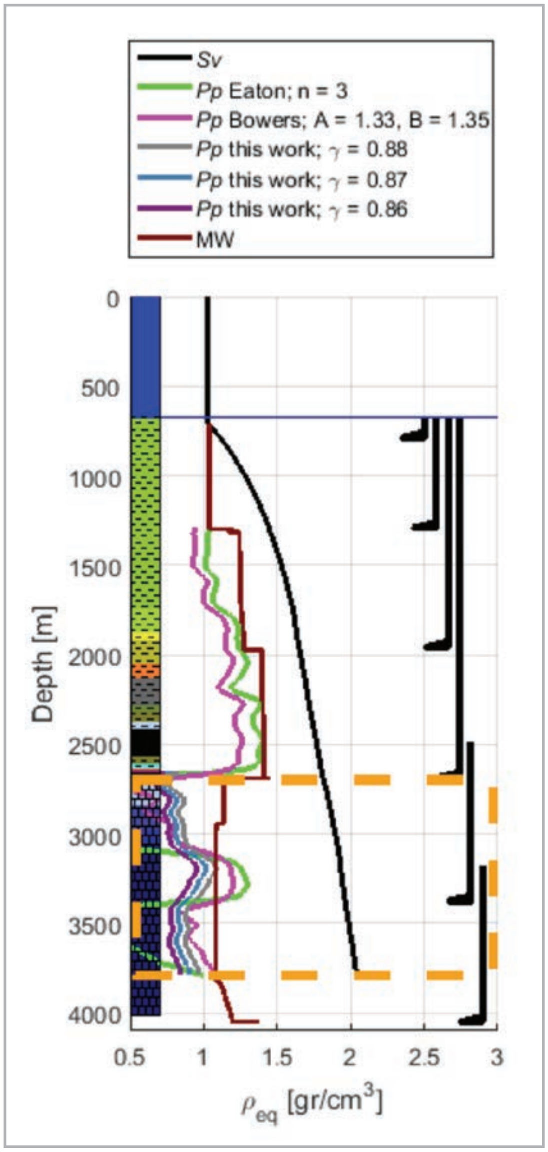

Figure 10. Comparison among different pore pressure prediction methods in well C.

In Tertiary formations, (depths lower than 2700 [m]), the methods that better fit the mud weight used while drilling well C are Eaton's and Bower's methods. In Cretaceous and Jurassic carbonate formations (depths greater than 2700 [m]), although Bower's method exhibited a response, it was considered it was not representative of the reported drilling data, because presence of gas or influx in that zone during drilling did not was recorded. On the other hand, three different lines can be observed that correspond to the application of the improved Atashbari's method; the purple line represents gamma equal to 0.86, gamma equal to 0.87 is represented by the steel blue line and gamma equal to 0.88 corresponds to the gray line. From **Figure 10** it can be noticed that the improved method fits better the mud weight than Bower's, due to all profiles present smaller values than the mud used during well C drilling. For the calculation of the improved Atashbari's method, a matrix of dolomite was supposed.

Figure 11 presents the pore pressure gradient profile of well C. This profile is estimated by a combination of Eaton's and Bower's method in Tertiary formations and the improved Atashbari's method for carbonate rocks. An exponent gamma equal to 0.86 was used in the improved method to calculate this final pore pressure profile.

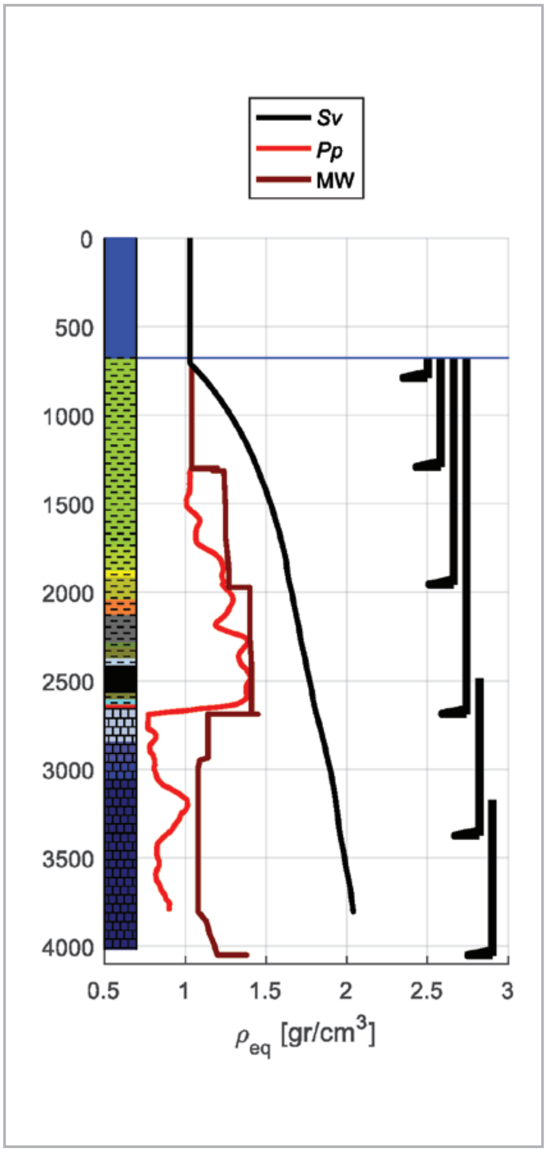

Figure 11. Complete pore pressure profile of well C.

Finally, **Figure 12** shows the full operative window of well C incorporating the fracture pressure gradient; again its calibration was done using LOT data, (navy squares).

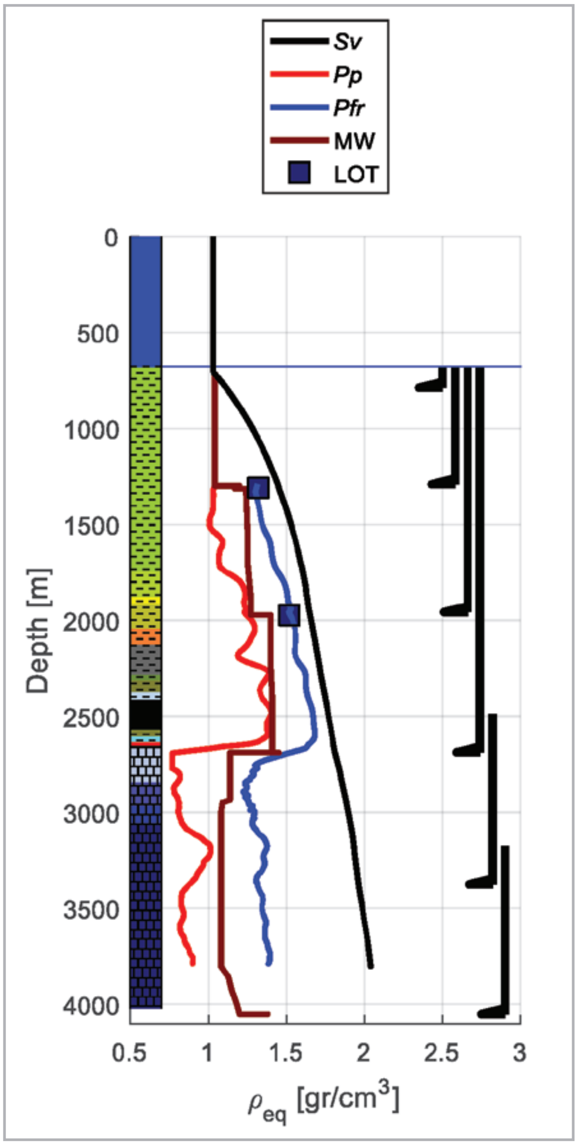

Figure 12. Operative window of well C.

Conclusions

This main aim of the present work has been to improve the pore pressure prediction method for carbonate rocks developed by Atashbari et al. (2012) A detailed flow diagram is presented in order to make easier the application of the method. The main mechanism of pore pressure generation considered by this method is loading, (compression).

This work describes three different applications of the advanced method to wells located in México. It can be concluded that the modified pore pressure prediction method presented in this paper behaves better in carbonate zones than Eaton's and Bower's methods, which is expected because Eaton's and Bower's methods were developed to pore pressure prediction in shale formations.

It is intended in further research to apply this work in natural fractured reservoirs or to adapt it to represent the pore pressure behaviour of such formations with vugs or large fractures.

Nomenclature

c_{bc}	Bulk compressibility when confining pressure is not constant.
c_{bp}	Bulk compressibility when pore pressure is not constant.
c_{pc}	Pore compressibility when confining pressure is not constant.
c_{pp}	Pore compressibility when pore pressure is not constant.
V_b	Bulk volume.
V_p	Pore volume.
i	Initial conditions, at the beginning of core test.
p_c	Confining pressure.
p_p	Pore pressure.
c_r	Rock or matrix compressibility.
ϕ	Porosity.
c_b	Bulk compressibility.
c_p	Pore compressibility
$\sigma_{effective}$	Effective stress.
γ	Gamma, empirical exponent for calibration.
K_r	Bulk modulus.
Sv	Vertical stress.
P_{pn}	Normal pore pressure.

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Semblanza del autor

Juan Pedro Morales Salazar

Ingeniero Petrolero egresado de la Universidad Nacional Autónoma de México, y Maestro en Ingeniería por la misma Universidad, donde actualmente se encuentra cursando el Doctorado en Ingeniería.

Ha colaborado como profesor de asignatura en la carrera de Ingeniería Petrolera de la UNAM. Se ha especializado en la disciplina de geomecánica aplicada a la perforación de pozos.