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Estimation Pore and Fracture Pressure Based on Log Data; Case Study: Mishrif Formation/Buzurgan Oilfield at Iraq

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Abstract

Prediction of the formation of pore and fracture pressure before constructing a drilling wells program are a crucial since it helps to prevent several drilling operations issues including lost circulation, kick, pipe sticking, blowout, and other issues. IP (Interactive Petrophysics) software is used to calculate and measure pore and fracture pressure. Eaton method, Matthews and Kelly, Modified Eaton, and Barker and Wood equations are used to calculate fracture pressure, whereas only Eaton method is used to measure pore pressure. These approaches are based on log data obtained from six wells, three from the north dome; BUCN-52, BUCN-51, BUCN-43 and the other from the south dome; BUCS-49, BUCS-48, BUCS-47. Along with the overburden pressure gradient and clay volume, which were also established first, data such as gamma ray, density, resistivity, and sonic log data are also required. A key consideration in the design of certain wells is the forecasting of fracture pressure for wells drilled in the southern Iraqi oilfield of Buzurgan. The pressure abnormality is found in MA, MB21, MC1 and MC2 units by depending on pore pressures calculated from resistivity log. In these units, depths and its equivalent normal and abnormal pressure are detected for all sex selected wells; BUCS-47, BUCS-48, BUCS-49, BUCN-43, BUCN-51 and BBCN-52. For MA, MB21, MC1, and MC2 units, the highest difference in pore pressure values are 1698 psi @ 3750 m (BUCN-51), 3420 psi @ 3900 m (BUCN-51), 788 psi @ 3980 m (BUCS-49), and 5705 psi @ 4020 m (BUCN-52). On other hands, MB11 and MB12 units have normal pressure trend in all studied wells. Finally, the results show that the highest pore and fracture pressure values is existed in North dome, in comparison with that obtained in south dome of Mishrif reservoir at Buzurgan oilfield.

Keywords: Pore pressure, Fracture pressure, Overburden pressure, Clay volume, Eaton method, Sonic log, Resistivity log, Abnormal pressure.

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1- Introduction

It is possible to characterize the pressure in formation pores as formation pressure. In several areas of well planning and management, formation pressure is a crucial variable to achieve the optimum drilling processes. It affects the choosing of mud weights, management on the majority of drilling issues including stuck drilling pipes, mud loss, and others, as well as casing-design [1].

For so, it is crucial to anticipate and identify pore and fracture pressure zones, which provide a number of hazards, including drilling fluid loss, kicks, blowouts, and other issues. Additionally, it's crucial to foresee the pressure at which rocks would fracture. Large amounts of drilling fluids may be lost as a result of these cracks or at subnormal pressure zones. A blowout or environmental pollution may result from formation fluids moving inside the wellbore or throughout the cracks up to the surface in the case of shallow depths [1, 2].

The prediction of fracture pressure requires the values of overburden and pore pressure. In this work, bulk density data are used for calculating overburden pressure [2]. It is crucial to forecast formation pore pressure by applying innovative techniques for pore pressure estimation in carbonate rocks. This approach of pore pressure estimation is restricted to the regions where the cores are accessible and is based on discovered values of rock bulk and pore compressibility that are acquired through special core analysis [3]. The used an advanced pattern recognition computer algorithm as well as seismic data and to forecast a pore pressure formation depending on well log data in the north-west of Saudi Arabia [4].

The goal of this study is to predict the pore and fracture pressure of Mishrif reservoir based on well log data from six wells separated at north and south dome. The abnormal pressure intervals of all six units MA, MB11, MB12, MB21, MC1, and MC2 need to detected to control and mitigate the drilling problems.

2- Area of Study

Near the Iranian border, 40 kilometers northeast of Amara in southern Iraq, is the Buzurgan oil field. The Mishrif Formation acts as a large reservoir in southern Iraq. The north dome and south dome are two of the domes in Buzurgan Field. Additionally, the south dome is larger than the north dome, which has dimensions of 23

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km by 8 km compared to 16 km by 6 km [5]. The location of the Buzurgan oil field is seen in Fig. 1.

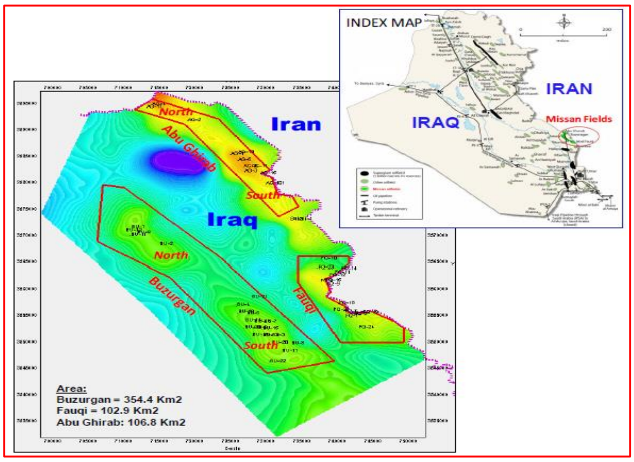

Fig. 1. The Location of the Buzurgan Oil Field in Iraq with North and South Domes [5]

3- Basic Concepts and Drilling Problems

3.1. Basic concepts

- Abnormal formation pressure is the divergence between the interstitial fluid pressure and the pore pressureof the subsurface fluids.
- The total height of a water column that extends from the ground to the formation of attention is proportional to the hydrostatic pressure. As a result, the pore pressurevaries generally at different places, and the normal calculated value is typically regarded to be 0.433*depth psi for fresh water and 0.465*depth psi for salty water.
- 1.0 psi/ft* depth is assumed to be the average total overburden pressure, which is the consequence of the combined pressure of the rocks (also known as rock matrix stress or grain-to-grain stress). A reservoir is said to have an excessively high pressure if the pore pressure gradient is between 0.465 and 1.0 psi/ft [6].
- Only the density of the fluid in the porous medium and the magnitude of the measured data will determine the pressure of the fluid in the sediment's porous structure (equal to the height of the column of liquid).

The pressure in the borehole with which a formation would fracture is known as the fracture pressure. A rock's internal tension may be broken down into three main stresses. When the least amount of tensions inside the rock structure are exceeded by the pressure in the borehole, a formation will fracture. These fractures often spread perpendicular to the direction of the least main stress [7].

3.2. Drilling problems with high-pressure reservoirs

Costly implications of reservoirs with excessive pressure involve follows [8]:

- Blowout; flowing formation fluid inside the well while drilling.
- Caving: When poor permeability rocks have large pore pressure, they stress-relieve or "cave" into the borehole.
- Stuck pipe – the drill pipe sticks to the side of the borehole because the sidewalls of the wellbore beside the bit swell (relieve stress).
- Lost circulation – the formations will break once pore pressureexceeds formation pressure, then the mud would be flow into drilled formation.

It is important to consider both the pressure of the fluids in the pores and the pressure at which the formations may fracture when drilling in locations where there are over-pressured sections. To avoid blowouts, using thicker mud alone is insufficient. The structure may burst unless the mud is excessively dense, losing circulation as a result. Generally, while boring, it is hard to ascertain such vital pressures in a different location [8].

3.3. Sub-Normal Pressure while drilling

Compared to high-pressured reservoirs, sub-normally pressured reservoirs have received far less attention. This is most likely because sub-normal pressures and under-pressures are linked with less dramatic drilling issues. However, there are issues that might be quite dangerous. Severe formation damage can happen if the reservoir pressure is significantly lower than the pressure of the drilling fluid. As the drilling mud filtrate permeates the reservoir, clays swell and move about, potentially clogging the pore throats. A low pressure producing gas well can be killed by even a little amount of water in the hole. Capillarity causes the water to be pulled into the pores, ruining the relative permeability to gas. It is preferable to put casing at the head of the reservoir range and drill using gas, salt water, or oil-based mud when working with low pressure gas sandstone reservoirs in order to reduce drilling problems. There will not be any sign of gas on the mud-log if the gas reservoir does have a low pressure. Reexamining the records of several abandoned dry holes is necessary to seek for bypassed gas zones [8, 9].

4- Research Methodology

This study explains the methods for estimating and calculating pore and fracture pressure as follows:

a) Overburden pressure and overburden pressure gradient (OBP and OBGrad).
b) Pore pressure and pore pressure gradient (PP and PPG) and
c) Fracture pressure and fracture pressure gradient (FP and FPG) [6, 10].

IP (Interactive Petrophysics) is a computer software application used to process and analyze logs data. In this study the (IP) software used to calculate the (OBGrad, PPG and FPG) using the software option “Pore pressure calculation”, from select the “advance interpretation” main tab.

Pore pressure calculation option divided into three parts where these parts are arranged step by step to calculate finally pore and fracture pressure. These steps are shown in Fig. 2 as follows [6, 11]:

Fig. 2. Steps of Pressure Calculation Option [11]

4.1. The Density Estimation Model

This model allows the user to generate a density curve from sonic log data in order to use it in the overburden gradient calculation. However, this option is used when the density log (RHOB) not available.

4.2. The Overburden Gradient Calculation (OBGrad)

This pressure obtained from collection the weight of the formation matrix (rock) and the fluids (oil, gas and water) in the pore space overlying the formation of interest. In the past, the overburden pressure gradient was assumed to be a constant approximately equals to (1.0) psi/ft. The need of a better definition of overburden gradients in terms of dependence on depth and formation type arise from the introduction of the new techniques for calculating the pore and fracture pressures. The errors caused by assuming constant values of improper overburden curves are unacceptable. It is possible to calculate the formation densities which the overburden comes from using the sonic log. In this manner, the overburden can be calculated in each well and, each time a set of logs is performed, the result is continuously updated overburden curves [12].

This module is consider as a second module within the pore pressure calculation option (IP software). At the reference depth, the average overburden gradient and overburden pressure can calculated and expected from this model [11].

The basic formula used to calculate the overburden pressure gradient given by AGIP [13] is shown in Eq. 1:

$$\sigma_v = g\int_0^D \rho_b \, dD \quad (1)$$

Where: σ_v is the vertical stress / overburden stress at depth TVD, psi. ρ_b is the bulk density (including the water section above sea floor, (lb/gal). g is the gravity constant (m/sec^2). D is the depth (parallel to the direction of gravity) (m).

The well input data requires to enable the user to select a depth Curve. The user can choose a density curve from the "Density Prediction" computation, an actual well log, or auto constant values of bulk density throughout a depth range by using input density curved or defined values [6, 11], as shown in Fig. 3.

For intervals where the density curve isn't available, the computing of the missing overburden gradient and pressure data can be provided by some options. This options permit to introduce a number of methods for determining a continuous overburden gradient curve from surface to total well depth. These methods are Amoco Avg. Sediment Density option or Amoco Compaction Relationship option or Lookup table's option, as shown in Fig. 3. In this study Amoco Compaction Relationship option is used to estimate ρ_{avag} in order to calculate the OBGrad upon the following Eqs. 2 and 3 [11, 13]:

$$OBG = [(8.5*W) + (\rho_{avag})*(D-W-A)]/D \quad (2)$$

Where: OBG = overburden gradient. W = water depth (ft). 8.5 = assumed sea water density (lb/gal). D = TVD depth below KB (ft). A = air gap (ft). ρ_{avag} = average sediment density (lb/gal, gm/cc, etc).

$$\rho_{avag} = 16.3 + [(D-W-A)/3125]^{0.6} \quad (3)$$

The value of W & A is used in offshore while these values will equal zero if this equation used in onshore.

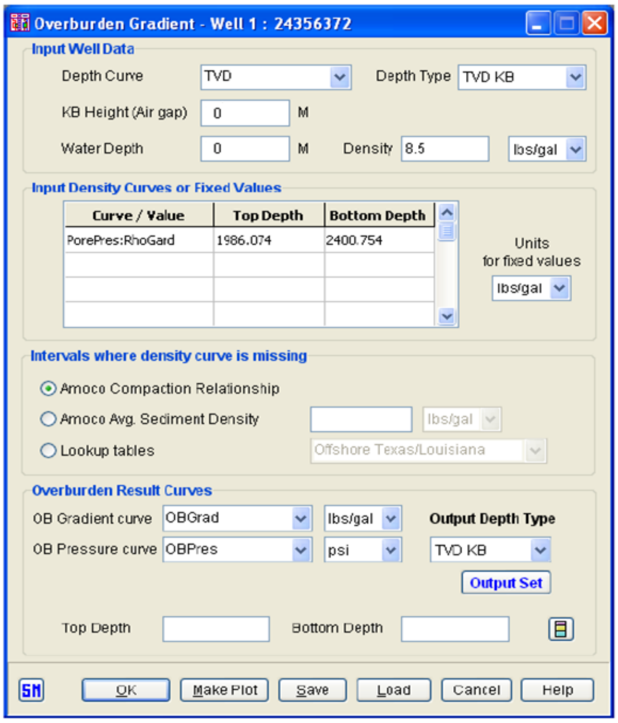

Fig. 3. Overburden Pressure Calculation Options [6, 11]

4.3. The Pore, and Fracture Pressure determination

Within the Pore Pressure Measurements selection, this module is regarded as being the 3rd module. Based on the examination of the supplied log data and supplementary drilling data, it offers an opportunity to decide Pore Pressure and Fracture Pressure estimates for the well beneath the consideration (if available) [6, 11].

The Input tab permit the user to choose the depth and log curves data for the study in order to obtain the Pore Pressure and Fracture Pressure Gradient models. The curves of log data can be chosen from menu boxes as shown in Fig. 4 [6, 11].

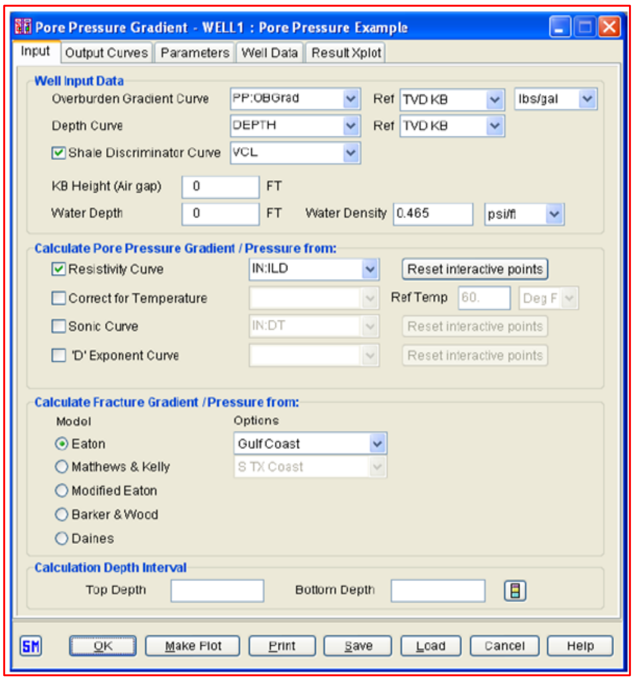

Fig. 4. Pore Pressure and Fracture Pressure Calculations [11]

4.3.1. Formation Pore Pressure (PPG)

In present day drilling and completion practices, both maximum well control (i.e. engineered drillable conditions) and minimum cost are the key factors.

The aim of good well planning and real drilling operations is to avoid or at least minimize the dangers of well kicks, stuck pipe, lost circulation, etc. The formation pore pressure and fracture pressure calculations are very important in cementing, hydraulic fracturing, etc. Today, seismic, drilling and well logging is greatly assist in the effort of predicting both pore and fracture pressures prior to spudding a well [12].

The calculate pore pressure gradients based on Eaton's methodology using different input data such as resistivity log, sonic log and/or a Drilling Exponent (dc_o) curve. The Eaton relationships are illustrated below [11]:

Eaton Method: Eaton suggested that geopressure magnitude may be calculated from log resistivity data [14] using the following Eqs. 4, 5, 6, and 7:

$$PPG = GOV - (GOV - GP_n) * \left(\frac{R_{obs}}{R_{nor}}\right)^{1.2} \quad (4)$$

If log conductivity values are used directly, the equation is as follows:

$$PPG = GOV - (GOV - GP_n) * \left(\frac{C_{nor}}{C_{obs}}\right)^{1.2} \quad (5)$$

When sonic log or seismic travel times are used, the following equation should be used:

$$PPG = GOV - (GOV - GP_n) * \left(\frac{\Delta t_{nor}}{\Delta t_{obs}}\right)^{3.0} \quad (6)$$

When the geopressure magnitude prediction equation using dc is similar to (3-1), as follows:

$$PPG = GOV - (GOV - GP_n) * \left(\frac{d_{co}}{d_{cn}}\right)^{1.2} \quad (7)$$

Where: GP = pore pressure gradient (psi/ft). GOV = overburden pressure gradient (psi/ft). GP_n = normal pore pressure gradient (psi/ft). R_{obs} = observed shale resistivity (ohm). R_{nor} = normal shale resistivity (ohm). Δt_{nor}= normal shale travel time (usec/ft). Δt_{obs}= observed shale travel time (usec/ft). C_{nor}= normal shale conductivity. C_{obs}= observed shale conductivity. Dc_o= drilling exponent in shale.

Finally drilling data are often used in geopressure magnitude calculations and the value of PPG and PP calculated and plotted versus depth from sonic log or log resistivity data.

4.3.2. Fracture Pressure Calculation

Fracture gradient (FP) can be defined as the pressure required to create fractures at a given depth and it is obtained from pore pressure and overburden gradient using Eq. 8 [13]:

$$FG= (K*(\sigma_v \ \alpha Pp) + \alpha Pp)/D \quad (8)$$

Where α is Biot coefficient and K, which equals the horizontal effective matrix stress multiplied by the vertical effective stress, is known as the stress ratio.

All methods for calculating Fracture Pressure are only different in computation of value of K [11].

Four methods are used to predict fracture pressure gradient [10, 11], these are:

1) Eaton Method.
2) Matthews & Kelly.
3) Modefied Eaton.
4) Barker & Wood

1) Eaton model

Tried to use the Poisson's Ratio to compensate for the underlying situation in the computation of fracture curves from Eq. 9.

$$\frac{F}{d} = \left(\frac{S}{d} - \frac{P}{d}\right) * \left(\frac{\mu}{1-\mu}\right) + \frac{P}{d} \quad (9)$$

Where: μ = poisons ratio. F/d = fracture gradient (Psi/ft). S/d = overburden gradient (Psi/ft). P/d = pore pressure gradient (Psi/ft).

This equation can be applied worldwide given that the following 3 steps are followed:

1. Determine overburden gradient.
2. Determine pore pressure gradient.
3. Determine poisson's ratio for the study area.

Poisson's Ratio Calculation (μ): This calculation is done by using follow Eq. 10 or 11:
0 – 4999 ft (Depth):

$$\mu = 0.2007142857 - \left[7.5\times10^{-9}\times(Depth)^2\right] + \left[8.0214286\times10^{-5}\times(Depth)\right] \quad (10)$$

> 5000 ft (Depth):

$$\mu = 0.3724340861 - \left[1.77258\times10^{-10}\times(Depth)^2\right] + \left[9.4748424\times10^{-6}\times(Depth)\right] \quad (11)$$

2) Matthews and Kelly Method

This model is assumes a constant OBGrad of 1 psi/ft. Matthews and Kelly derived Ki curves from plots of effective overburden stress (S-P) vs Ki. Matthews and Kelly introduced a new method to calculate fracture pressure gradient. The formula which used as shown in Eq. 12.

$$FPG = GP + Ki\ (\sigma / Di) \quad (12)$$

Where: FPG=fracture pressure gradient (Psi/ft). GP=pore pressure gradient (Psi/ft). Ki = the effective stress coefficient. σ= effective stress.

The stepwise procedure of calculating the fracture pressure gradient by the Matthews and Kelly method includes:

1- Determine the pore pressure (from well logs, offset well data ...etc.)

2- Calculate the effective stress, σ, using Eq. 13:

$$\sigma = (1.0 * D) - (G_p * D) \quad (13)$$

Where, 1.0, represent the value of normal overburden pressure gradient which assumed to be constant.

3- Determine depth Di for which the σ-value would be the normal value by using Eqs. 14 and 15:

$$\sigma = [(1.0 - 0.465) * D_i] \quad (14)$$

$$D_i = \frac{\sigma}{0.564} \quad (15)$$

i.e., (0.465) represents the assumed value of normal pore pressure gradient.

4- Calculate the fracture pressure gradient from Eq. 12.

3) Modified Eaton Fracture Gradient Model

Simmons and Rau (1988) suggested this approach as a correction to the Eaton method for forecasting Fracture Pressures/Gradients. The supplied Overburden Gradient curve must be referred to a TVD under Sea baseline when utilizing this Fracture Gradient equation [6, 11]. This model is done by four step:

1. The composite vertical stress approch takes the overburden gradient curve as an input. 16:

$$\sigma_{vc=(0.442*WD)+(OBGrad*D_{Sed})} \quad (16)$$

Where: σ_{vc}= Composite Vertical Stress. *WD* = Water Depth (ft), equal zero at onshore wells. *OBGrad*= Overburden Gradient curve (psi/ft). *Dsed*= Sediment Penetration Depth (ft).

2. This information is used as an input in Eq. 17's computation of the matrix stress ratio (Ke) at the effective depth (Deff).

$$Ke = 0.05329427 * 0.99996^{Deff} * Deff^{0.3006479}) \quad (17)$$

Where: Deff = the effective sediment penetration depth defined by using Eq. 18:

$$Deff = (Water\ Depth/2) + DSed \quad (18)$$

3. Eq. 19 determines the Fracture Pressure utilizing Eaton's fundamental Fracture Pressure model.

$$FP = PP + Ke\,[\sigma_{vc} - PP)\,] \ldots \quad (19)$$

Where: FP = Fracture Pressure (psi). PP = Pore Pressure (psi). Ke= Matrix stress Ratio. σ_{vc} = Composite Vertical Stress.

By subtracting the related depth value from each estimated pressure, the fracture pressure gradient is determined.

4) Barker and Wood method

They have only been utilized for pre-drill subsurface under mud level estimate. Because the model predicts that the fracture gradient in the shallow sediment overburden will be identical to the overburden gradient, it is possible to determine the fracture gradient via divide the overburden pressure through the range of concern depth [11]. Where the Overburden pressure (which equal to fracture pressure) can calculated after determine average bulk density from Eq.20 as follows:

$$Cum.\ Av.\ Formation.\ Bulk\ Density\ (ppg) = 5.3 * (TVDBML)\ 0.1356 \quad (20)$$

5- Results and Discussion

In this study, the log data are prepared for BUCN-43, BUCN-51, and BUCN-52 wells from north dome while BUCS-47, BUCS-48, and BUCS-49 wells from south dome. Depending on Gamma Ray log data the shale volume (VCL) is calculated. The overburden pressure (OBpres) is determined depending on bulk density (RHOB) log data and Amoco Compaction Relationship. The Sonic log and/or Resistivity log data, overburden pressure, and shale volume by using Eaton method are used to predict the formation pore pressure in all six selected wells. Fracture pressure is estimated depending all mentioned data by four methods; Eaton Method, Matthews and Kelly, Modified Eaton and Barker and Wood. The final results are shown in Fig. 5 to Fig. 7 for south dome wells and Fig. 8 to Fig. 10 for north dome wells.

Typically, it is important to control the shale-base-line at high and low shale volume zones by splitting the main zones to different small intervals. Thus, pore pressure gradient is very effected by the number of splitting intervals which increased the accuracy of pressure calculation.

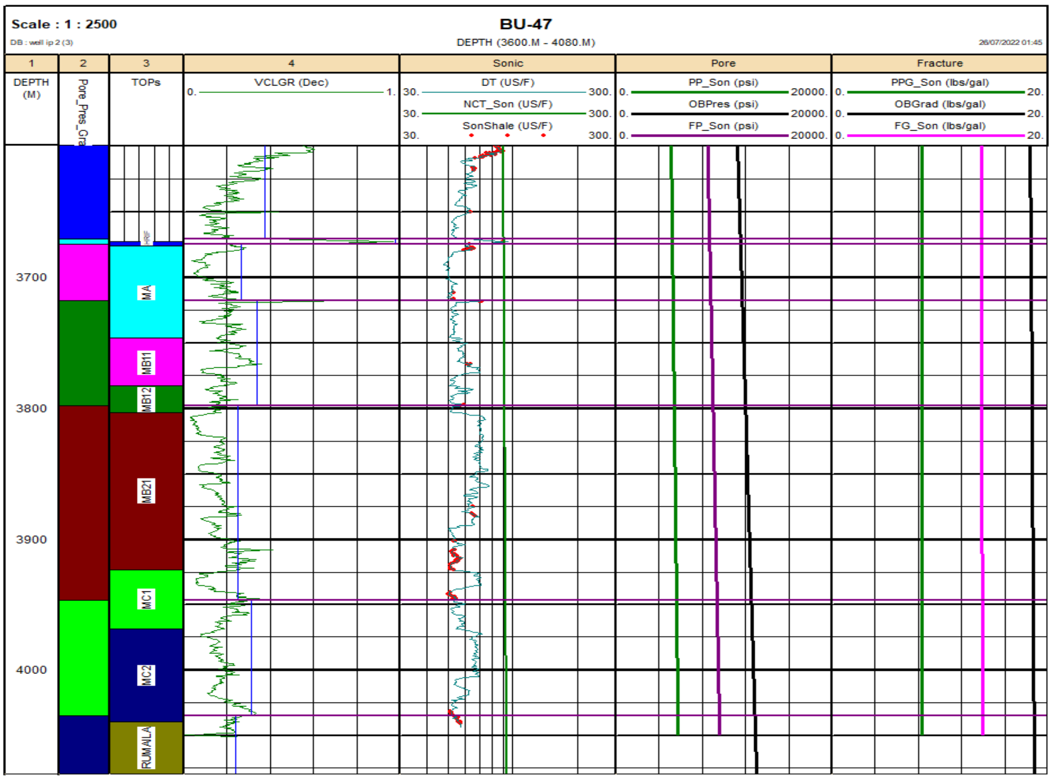

Fig. 5. Pore and Fracture Pressure Interpretation Result for BUCS-47

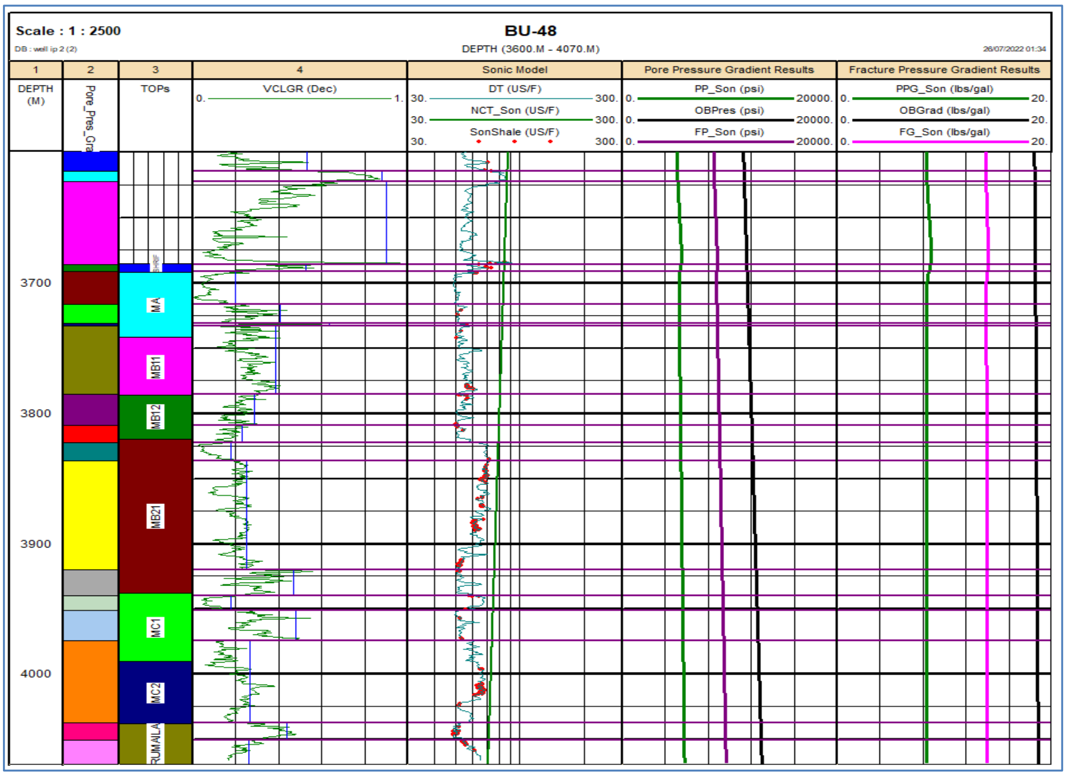

Fig. 6. Pore and Fracture Pressure Interpretation Result for BUCS-48

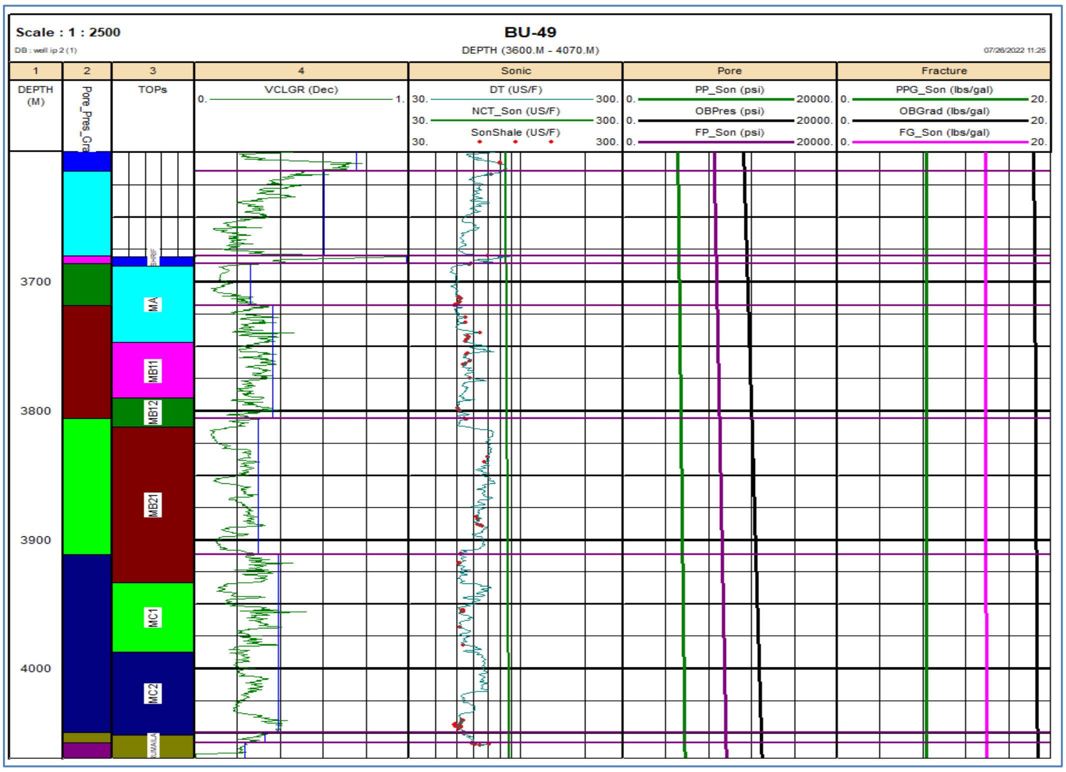

Fig. 7. Pore and Fracture Pressure Interpretation Result for BUCS-49

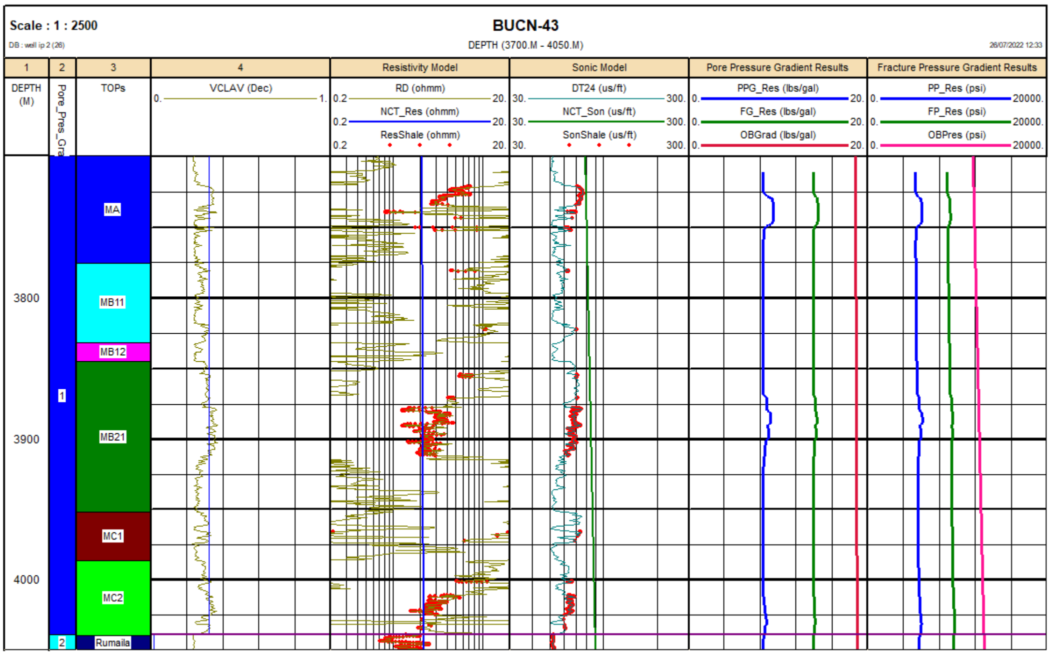

Fig. 8. Pore and Fracture Pressure Interpretation Result for BUCN-43

In addition, the results show that the highest pore pressure is at BUCN-43 and the lowest is at BUCS-48 for MA unit. For MB11 and MB12 units, highest pore pressure is at BUCN-52 and the lowest is at BUCS-48. For MB21, MC1 and MC2 units, highest pore pressure is at BUCN-43 and the lowest is at BUCS-47. For MC1 unit, highest pore pressure is at BUCN-43 and the lowest is at BUCS-47.

Consequently, the outcomes display that the maximum fracture pressure is at BUCN-43 and the lowest is at BUCS-47 for MA, MB21, and MC2 units. For MB11 and MB12 units, highest pore pressure is at BUCN-52 and the lowest is at BUCS-48. For MB12 and MC1 units, highest pore pressure is at BUCN-52 and the lowest is at BUCS-47. Table 1 and Table 2 present the average overburden (OBP), Pore (PP), and Fracture (FP) pressure for six Mishrif Formation units from six wells.

In addition, by using the resistivity log data, the pore and fracture pressure is calculated for selected wells aimed at all Mishrif units. However, using sonic log data for calculating pore and fracture pressure gave the normal pressure trend without any abnormalities intervals. On other hands, the pressure abnormality is found in MA, MB21, MC1 and MC2 units by depending on pore pressures calculated from resistivity log. In these units, depths and its equivalent normal and abnormal pressure are detected for all sex selected wells; BUCS-47, BUCS-48, BUCS-49, BUCN-43, BUCN-51 and BBCN-52. For MA, MB21, MC1, and MC2 units, the highest difference in pore pressure values are 1698 psi @ 3750 m (BUCN-51), 3420 psi @ 3900 m (BUCN-51), 788 psi @ 3980 m (BUCS-49), and 5705 psi @ 4020 m (BUCN-52). On other hands, MB11 and MB12 units have normal pressure trend in all studied wells. Note that the difference in pore pressure values is calculated depending in follow formula; (pore pressure by resistivity log or sonic log – normal pressure from depth m* 3.28 ft/m *0.052* 8.33 ppg). Fig. 11 to Fig. 16 are presented to show the results of pressure calculation from both sonic and resistivity log data.

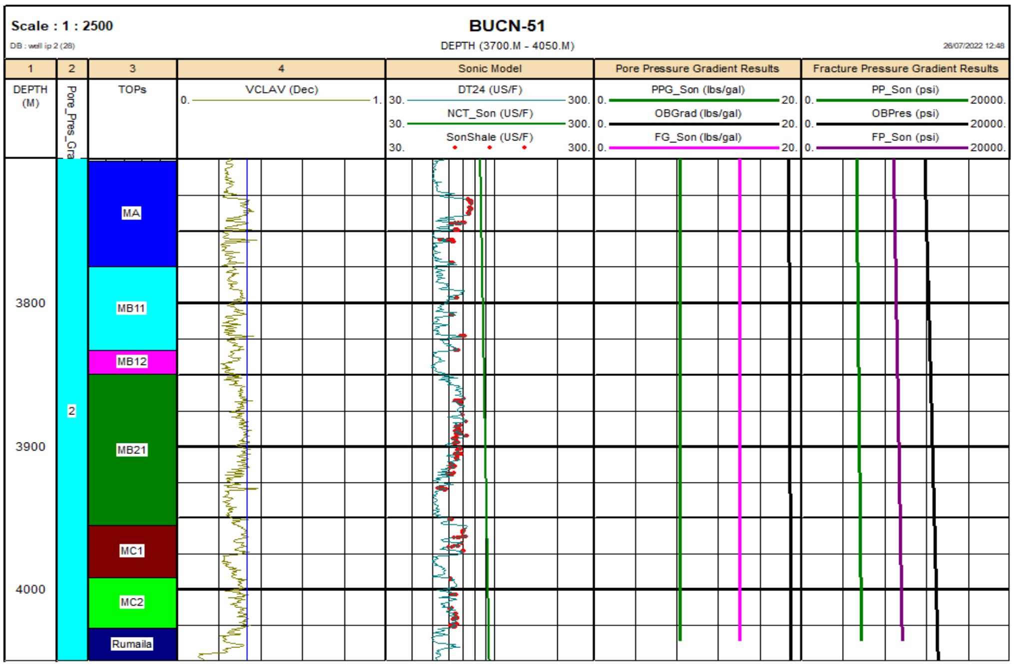

Fig. 9. Pore and Fracture Pressure Interpretation Result for BUCN-51

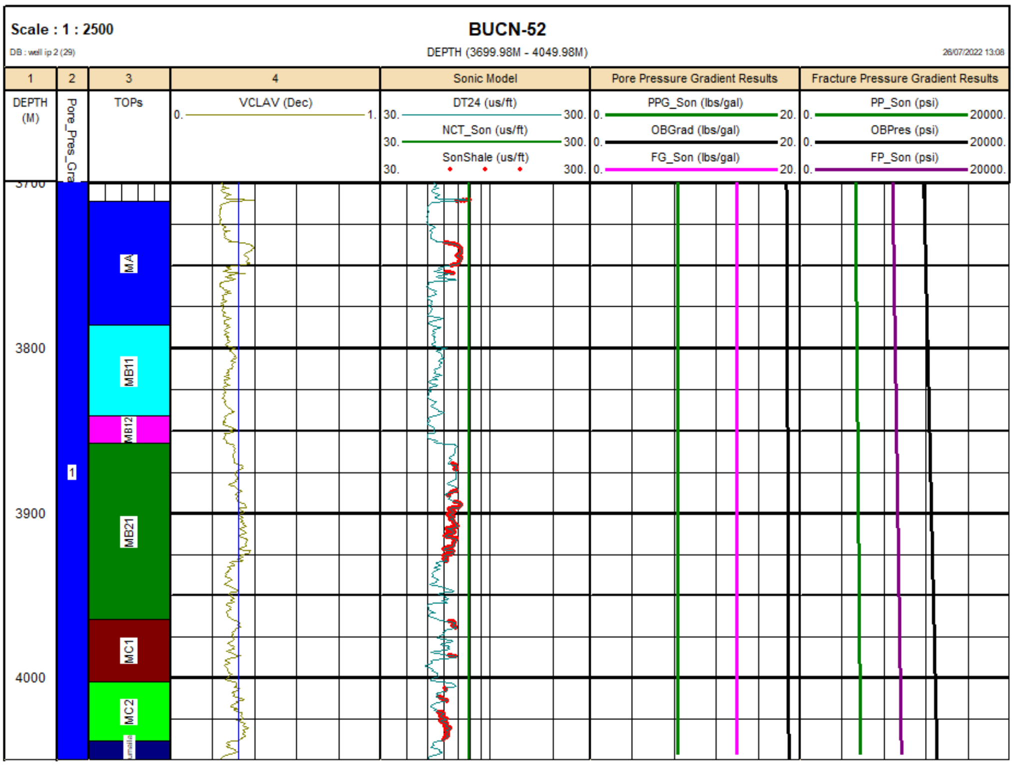

Fig. 10. Pore and Fracture Pressure Interpretation Result for BUCN-52

Table 1. Overburden, Pore, and Fracture Pressure for North Dome Wells

Well	BUCN-52			BUCN-51			BUCN-43		
Unit	OBP	PP	FP	OBP	PP	FP	OBP	PP	FP
MA	11933.9	5320.05	8912.22	11932.1	5305.27	8911.84	11853.1	5569.61	8998.12
MB11	12227.3	5433.25	9110.15	12192.1	5404.83	9087.15	12110.34	5404.84	9035.95
MB12	12374.1	5490.15	9208.82	12341.6	5461.73	9187.39	12258.23	5461.73	9135.43
MB21	12586.0	5575.49	9351.68	12555.3	5547.07	9331.34	12503.59	5679.93	9354.69
MC1	12839.6	5675.05	9521.05	12809.0	5646.63	9500.91	12789.04	5675.08	9492.73
MC2	12984.39	5731.958	9617.276	12954.43	5703.53	9597.56	12933.89	5822.12	9630.00

Table 2. Overburden, Pore, and Fracture Pressure for South Dome Wells

Well	BUCS-47			BUCS-48			BUCS-49		
Unit	OBP	PP	FP	OBP	PP	FP	OBP	PP	FP
MA	11708.2	5291.1	8797.8	11719.7	5291.1	8810.2	11705.4	5291.1	8797.6
MB11	11897.9	5362.2	8925.5	11906.0	5362.2	8936.1	11929.5	5376.4	8948.9
MB12	12011.3	5404.9	9001.7	12018.1	5404.9	9011.5	12078.0	5433.3	9048.9
MB21	12222.0	5490.2	9144.6	12303.8	5518.6	9204.5	12286.8	5518.6	9190.6
MC1	12516.4	5604.0	9341.7	12667.9	5660.9	9448.0	12579.1	5632.4	9386.2
MC2	12772.9	5703.6	9512.5	12847.4	5732.0	9567.7	12797.2	5717.8	9531.5

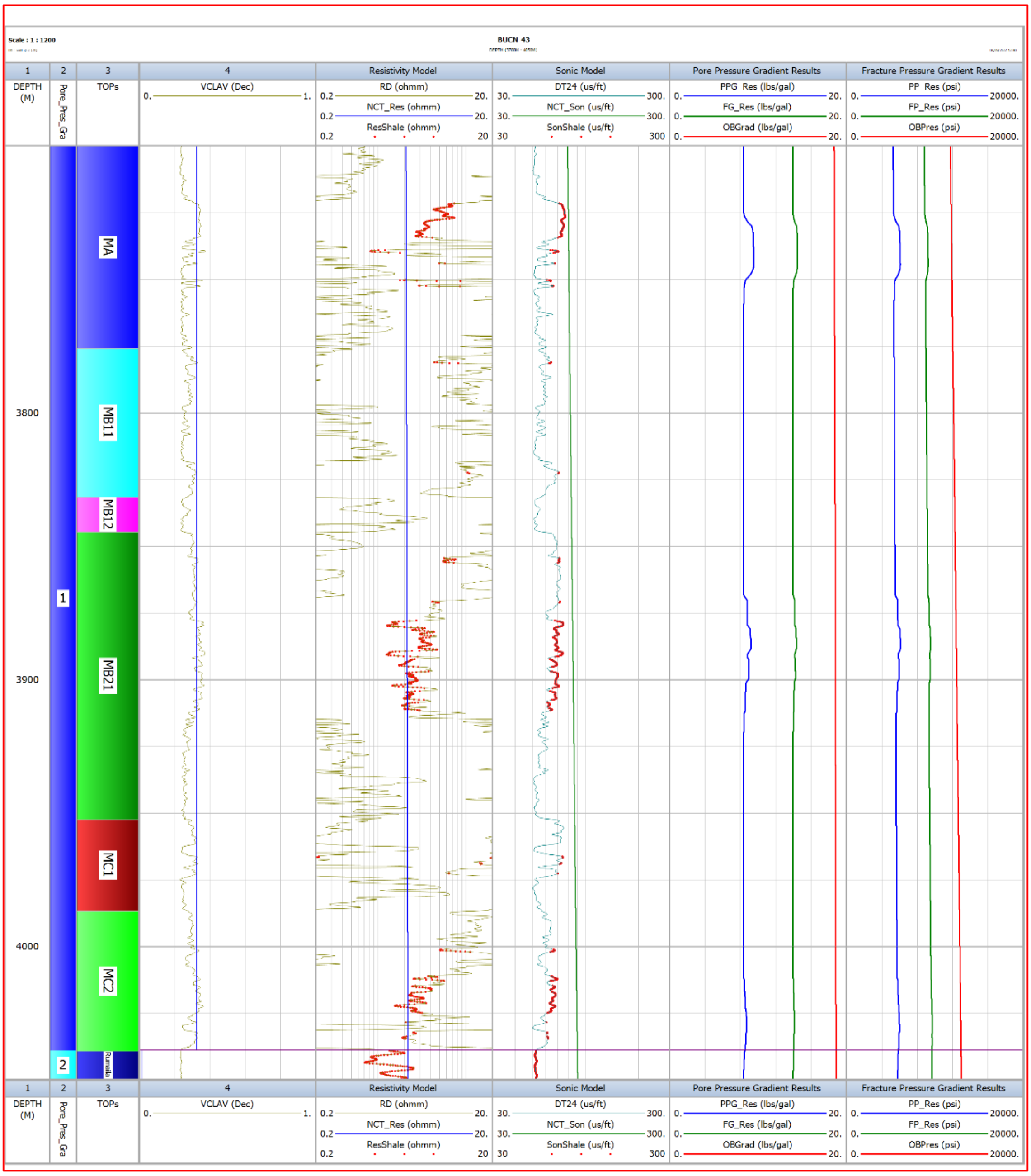

Fig. 11. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCN-43

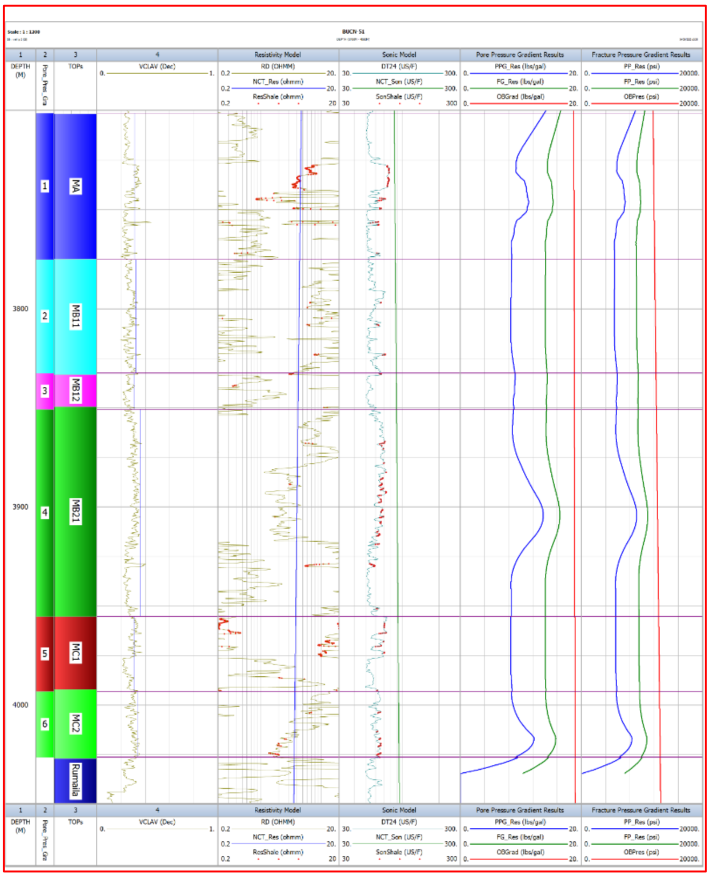

Fig. 12. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCN-51

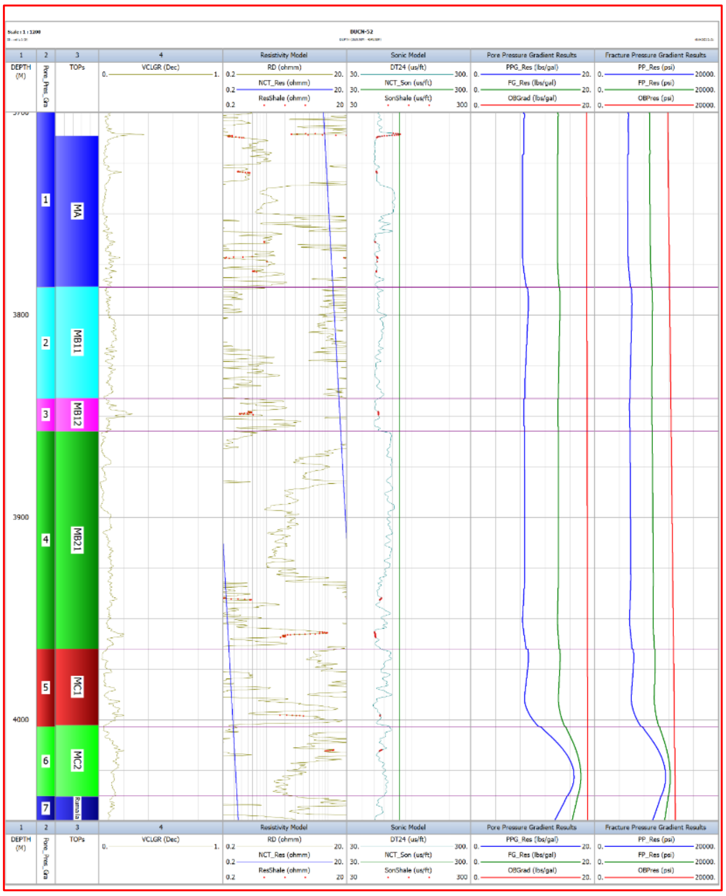

Fig. 13. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCN-52

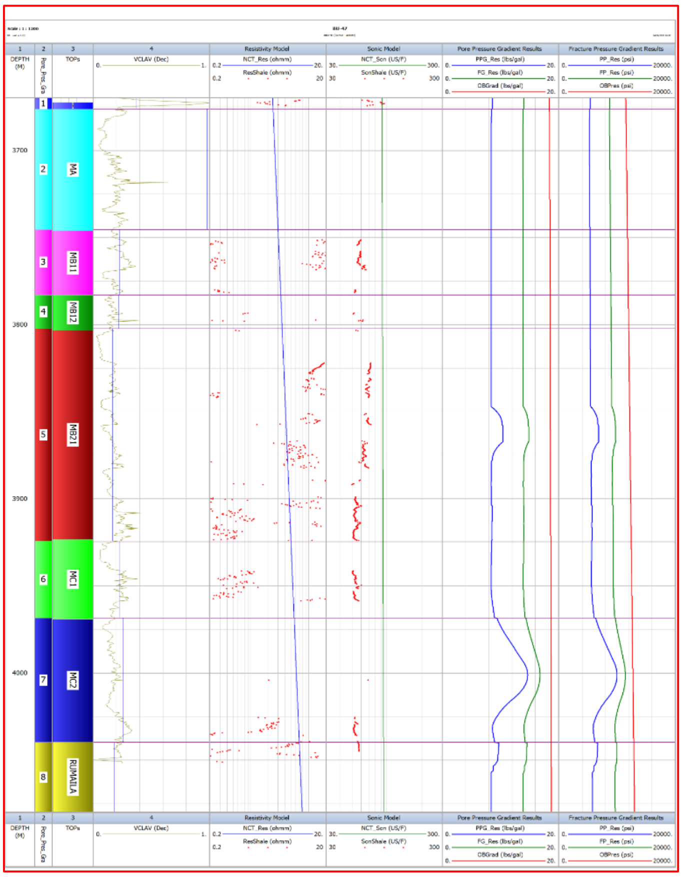

Fig. 14. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCS-47

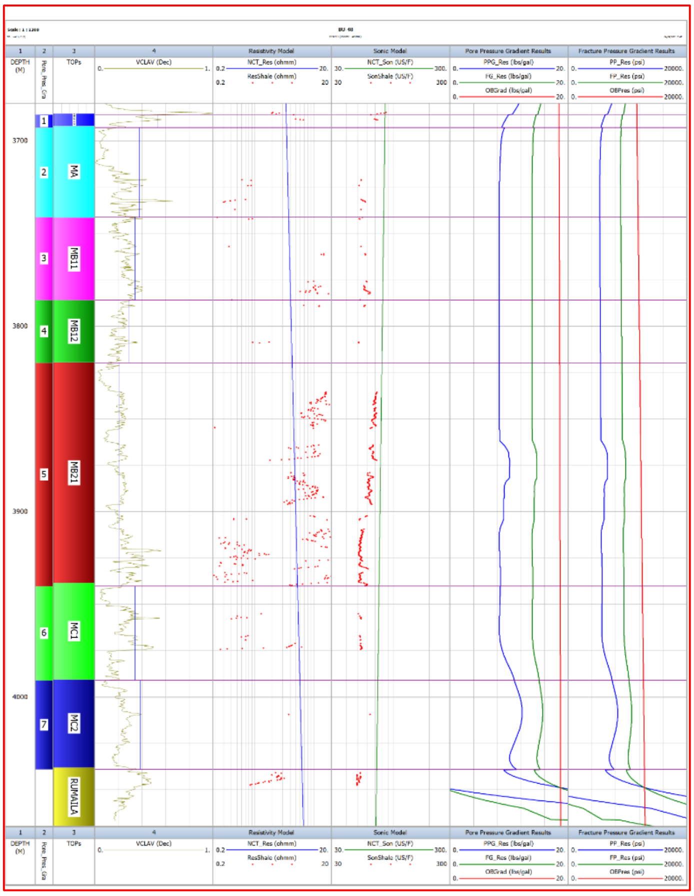

Fig. 15. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCS-48

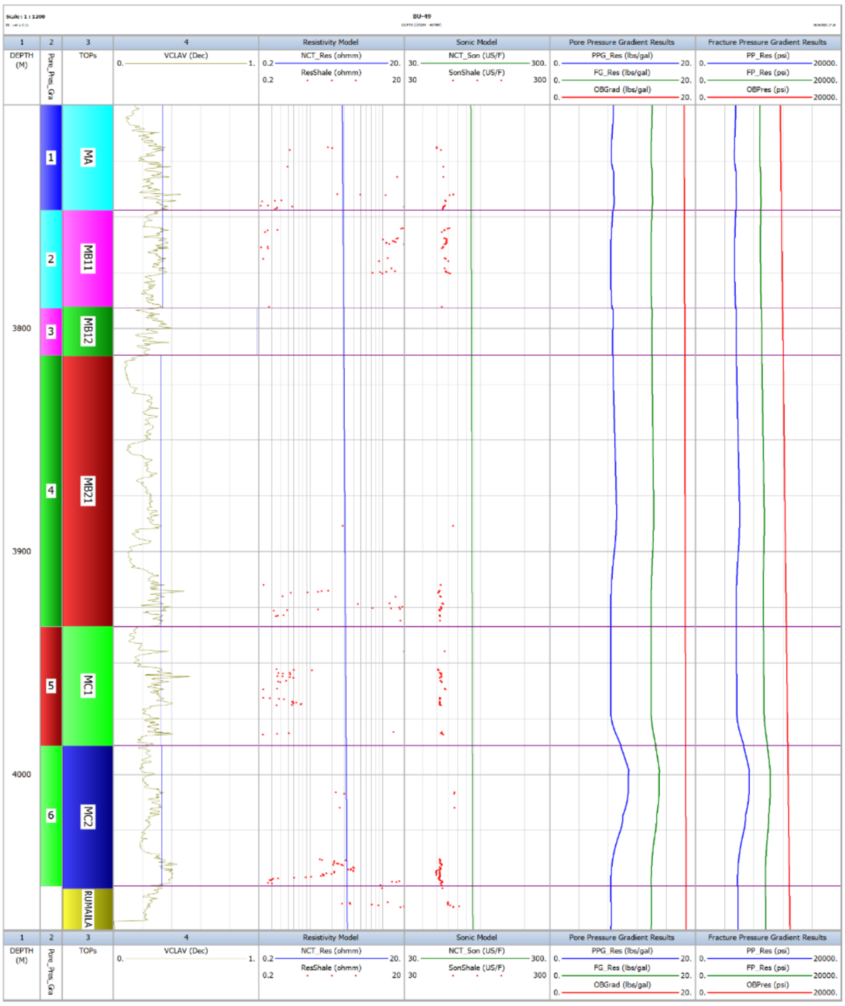

Fig. 16. Results of Pressure Calculation from Sonic and Resistivity Logs for BUCS-49

6- Conclusion

Calculating the pore and fracture pressure are the crucial factor to prevent many drilling problems during drilling new wells through Mishrif reservoir. Thus, some highlight points are concluded as follows:

- Pore pressure calculation by Eaton Method gave a valuable results for Mishrif formation units.
- Fracture pressure determination by modified Eaton method is considered the best method for Mishrif formation units.
- Using sonic log for estimation of pore pressure is more accurate while it's not need more environment corrections.
- The highest average pore and fracture pressure values is existed in wells BUCN-43 and BUCN-52, while the lowest values in existed in BUCS-47 and BUCS-48.
- North dome of Mishrif formation has highest pore and fracture pressure than south dome.
- The results of pressure calculation from sonic log data gave a normal trend, while its provided an abnormal trend during using resistivity log data.
- The pressure abnormality is found in MA, MB21, MC1 and MC2 units by depending on pore pressures calculated from resistivity log. On other hands, MB11 and MB12 units have normal pressure trend in all studied wells.
- Intervals and its equivalent normal and abnormal pressure are detected for all sex selected wells; BUCS-47, BUCS-48, BUCS-49, BUCN-43, BUCN-51 and BBCN-52. For MA, MB21, MC1, and MC2 units, the highest difference in pore pressure values are 1698 psi @ 3750 m (BUCN-51), 3420 psi @ 3900 m (BUCN-51), 788 psi @ 3980 m (BUCS-49), and 5705 psi @ 4020 m (BUCN-52).

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تخمين الضغط المسامي وضغط التكسير اعتمادا على بيانات تخطيط الابار لمكمن المشرف حقل بزركان النفطي

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الخلاصة

عند تصميم برنامج الحفر للابار النفطية فإن التنبؤ بضغط مسام التكوين وضغط التكسير يكون بالغ الأهمية لأنه يساعد على منع العديد من مشاكل عمليات الحفر بما في ذلك خسارة دورة سائل الحفر، والرفسة، و التصاق الأنابيب، والانفجار، وغيرها من المشاكل الاخرى. يستخدم برنامج IP لإجراء العمليات الحسابية وقياس ضغط المسام والتكسير. تُستخدم معادلات إيتون، ماثيوز وكيلي، إيتون المعدلة، و باركر وود لحساب ضغط التكسير، بينما تستخدم طريقة إيتون لقياس ضغط المسام. تستند هذه الطرق إلى بيانات تخطيط الابار التي تم الحصول عليها من ستة آبار: ثلاثة من القبة الشمالية BUCN−43, BUCN−51, BUCN−52 وثلاثة من القبة الجنوبية BUCS−47, BUCS−48, BUCS−49. بالإضافة الى تدرج ضغط وزن الطبقات وحجم الطين اللذين تم إحتسابهما أيضًا في بداية الحسابات لذلك اعتمدت هذه الحسابات على بيانات تخطيط الابار مثل أشعة كاما والكثافة والمقاومة وبيانات السجل الصوتي. أن أحد الاعتبارات الرئيسية في تصميم بعض الآبار هو التنبؤ بضغط التكسير للآبار المحفورة في حقل بزركان النفطي بجنوب العراق.

الضغوط الغير طبيعية تم حسابها لستة ابار اعتمادا على بيانات مجس المقاومة، حيث اظهرات النتائج وجود ضغوط غير طبيعية في الوحدات MA, MB21, MC1, MC2 بينما الوحدات MB11, MB12 لها ضغوط طبيعية. أخيرًا، أظهرت النتائج أن أعلى قيم ضغط المسام والتكسير موجودة في القبة الشمالية مقارنة بالقبة الجنوبية لمكمن المشرف في حقل بزركان النفطي.

الكلمات الدالة: الضغط المسامي، ضغط التكسير، ضغط وزن الطبقات، حجم الطين، طريقة ايتان، المجس الصوتي، مجس المقاومة، الضغوط الغير طبيعية.