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Determination of a potentially optimal zone to perform hydraulic fracturing work, Upper Magdalena Valley basin, Colombia

Determinación de una zona potencialmente óptima para realizar trabajos de fracturamiento hidráulico, Valle Superior del Magdalena, Colombia

Carlos Fabián **Sánchez**[1], Indira **Molina**[2], Gabriel Ángel **Molina**[3]

1 Universidad de los Andes, Bogotá, Colombia

2 Universidad de los Andes, Bogotá, Colombia. Now at Servicio Geológico Colombiano, Bogotá, Colombia, cmolinap@sgc.gov.co

3 Consultant, Bogotá, Colombia

Corresponding author: Carlos Fabián Sánchez, cf.sanchez@uniandes.edu.co

Abstract

The present study was carried out for an oil field located in the upper Magdalena Valley basin, Colombia, in which successful hydraulic fracturing was carried out in a well, which we denote *fractured*. The main objective is to replicate this technique in an existing well in the same field. For this work, electrical logs from twelve wells, including the fractured well, were analyzed to obtain a correlation between the area of interest, located in the Monserrate Formation, and each of the wells under study. By using *gamma ray*, resistivity, neutron and density logs, the petrophysical properties were calculated to determine the shale volume, effective porosity, total porosity, water saturation and permeability in each well. Additionally, the production history of each of the wells and the calculations described above were used to suggest a new site where hydraulic fracturing could also be successful. Two candidates were proposed in this study, one based on the similarity of its petrophysical properties, and another based on the consideration of additional production data. Notably, this well stimulation technique has global importance and has produced positive impacts on increased oil production where it has been implemented. The purpose of this study is to provide technical support for the decision to replicate this procedure in a new area of the field.

Keywords: Hydraulic fracturing, petrophysics, electrical logs, correlation.

Resumen

El presente estudio fue realizado para un campo petrolero ubicado en la cuenca del valle superior del Magdalena, Colombia, en el cual se realizaron trabajos exitosos de fracturamiento hidráulico en un pozo, al cual denominaremos *fracturado*. Como objetivo principal, se busca replicar esta técnica en un nuevo pozo ya existente en el mismo campo. Para el desarrollo de este trabajo se analizaron los registros eléctricos provenientes de doce pozos, incluyendo el fracturado, con el fin de obtener una correlación de la zona de interés,

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ubicada en la Formación Monserrate, con cada uno de los pozos en estudio. Gracias a los registros de *gamma ray*, resistividad, neutrón y densidad, se realizaron los cálculos de las propiedades petrofísicas, determinándose los volúmenes de shale, las porosidades efectiva y total, las saturaciones de agua y la permeabilidad en cada pozo. Adicionalmente, se utilizó la historia de producción de cada uno de los pozos, y los cálculos explicados anteriormente para sugerir un nuevo sitio donde el fracturamiento hidráulico podría ser exitoso también. Dos candidatos fueron propuestos en este estudio, uno a partir de la similitud en sus propiedades petrofísicas y otro integrando datos adicionales de producción. Cabe destacar la importancia que ha tenido esta técnica de estimulación de pozos a nivel mundial y su impacto positivo en el incremento en la producción de petróleo donde se ha implementado. La finalidad de este estudio radica en soportar, con argumentos técnicos, la decisión de replicar este procedimiento en una nueva zona del campo.
Palabras clave: Fracturamiento hidráulico, petrofísica, registros eléctricos, correlación.

1. Introduction

Hydraulic fracturing is a well stimulation technique used in the oil industry to increase production. It consists of injecting, at a certain depth, a mixture of fluids at high pressure, composed mostly of water (usually more than 95% of the mixture) and, to a lesser extent, chemicals and proppants that are responsible for keeping fractures open at the end of the procedure (Rutqvist, 2000). This injection method is applied mainly in low-permeability rocks since generating fractures via stimulation can increase the area of rock in contact with high-permeability channels and thus increase the production of the well (Atkinson, 2015). This technique was used for the first time in the United States in 1948 (Hubbert and Willis, 1957). Since the beginning of the new millennium, a derivative of this technique known as *fracking* began to be applied in unconventional

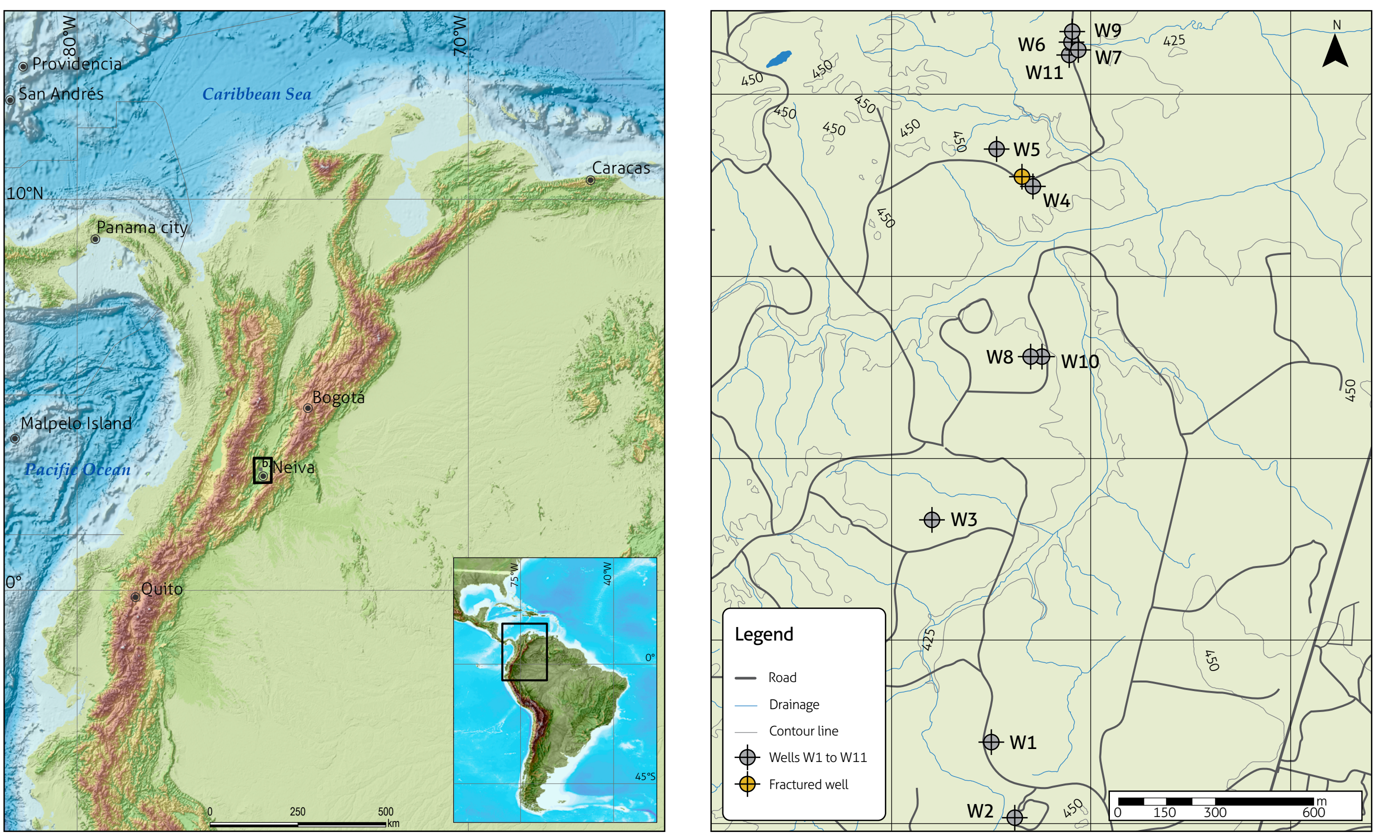

Figure 1. a) General location of the area. b) Distribution of wells in the field of the Upper Magdalena Valley basin, Colombia

deposits. These deposits correspond to formations of very low permeability that are rich in organic matter and are utilized with an extraction method that requires greater complexity and investment than conventional production techniques. In the case of fracking, horizontal wells are drilled, and stimulation is performed in a multistage manner on a larger scale, different from the procedure performed in this work, which consisted of the stimulation of an approximately vertical well.

The study area is located in the upper Magdalena Valley basin (Figure 1), which is one of the most important oil sources in Colombia, with three of the main reservoirs in the Honda, Caballos and Monserrate formations (Kairuz *et al.*, 2000). The formation under study is Monserrate, mainly composed of sandstones and Cretaceous clays. The fractured well is vertical with slight deviations and an artificial lift system of progressive cavity pumping. This well was stimulated toward the end of 2016 (Figure 2) in three intervals of interest (3775-3780', 3794-3799' and 3811-3816') in the Monserrate Formation. Fracturing was performed to improve the permeability of channels in the formation and increase the production of the well. A total of 903 bbl of fracture fluid was pumped with 39,320 lb of 20/40 carbolite as the proppant. The stimulation effectively increased the productivity of the well, given that by the end of 2016, the well produced approximately 40 barrels of oil per day (BOPD), and after applying the technique, daily production amounts above 100 BOPD were reached, leaving fractures with an average width of 0.04 in and conductivity of 1500 mD*ft.

The increase in production was reflected immediately after applying hydraulic fracturing. During the first semester of 2017, a decrease in production was observed, which is why maintenance was performed at the wellhead in July of that same year, which again resulted in an increase.

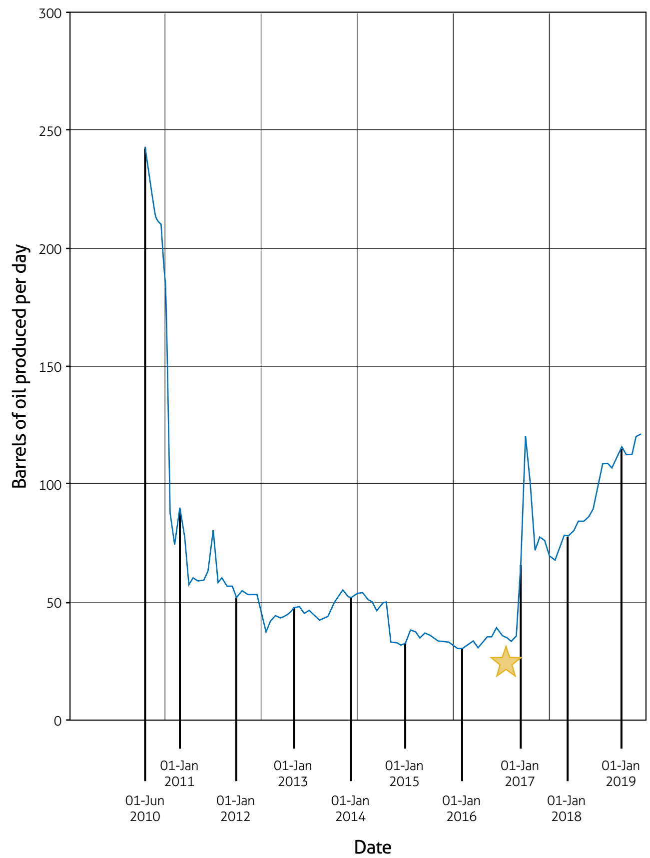

Figure 2. Production history of the fractured well from its inception in 2010 to April 2019
The star indicates the moment when hydraulic fracturing was performed at the end of 2016.

2. Methodology and data

Given that all resources are found in the subsoil, it is not possible to obtain a real view of the structure and properties of the deposit; however, through exploration techniques, structural approximations can be generated, and petrophysical properties can be determined. In this work, well logging data was used; this technique consists of sending active signals and/or capturing passive signals to a formation (Beck, 1981) to obtain its resistivity, natural radioactivity, spontaneous potential, porosity and density. The *gamma ray* tool measures the natural emission of gamma rays by the formation, which is proportional to the presence of U, Th and K, which are elements associated with the clay content in a formation. The resistivity tool emits electrical currents through the rock to obtain resistivity data, which are related to the type of fluid stored in the pores since high resistivity values correspond to hydrocarbons, and low values correspond to water (Bendeck, 1992). The neutron tool provides an estimate of the porosity of the formation based on the emission of neutrons toward the reservoir, measuring the attenuation by hydrogen as they advance in the medium; the fewer neutrons are detected, the greater the porosity. Finally, the density tool emits gamma rays toward the rock and records how many return to the sensor to estimate the density of the formation (Glover, 2000).

Once the petrophysical properties are obtained, they can be correlated to obtain a spatial mapping. In this work, logs from eleven wells drilled in the Monserrate Formation were used to correlate their properties with those of the fractured well; further reliance on historical production data and drilled and current well conditions obtained directly from the field in question made it possible to support an operational decision based on technical criteria.

2.1. Lithostratigraphic correlation

Due to operational decisions, wells P1 and P2 were not considered for the analysis because they are too old and do not have enough log information. Data processing was performed with Techlog software (Schlumberger, 2017). To obtain the correlation, the gamma ray and formation resistivity logs of the fractured well were used to identify the interval of interest corresponding to the wells drilled where hydraulic fracturing was performed. Once this area of interest was identified, the aforementioned logs from wells P3 to P11 were analyzed to identify the Monserrate Formation in each of them. In most of the wells, resistivity and gamma ray patterns were identified that allowed easy correlation of this formation. However, in wells P10 and P11, there were no similar patterns, so it was necessary to use the drilled well holes as a guide to locate the area of interest.

2.2. Petrophysical property calculations

Petrophysical properties reveal the interaction of the rock with the fluids that are stored in it. Using gamma ray, resistivity, neutron and density logs, the following properties were obtained: shale volume, total and effective porosity, water saturation and permeability. Each calculation was performed using the aforementioned Techlog software (Schlumberger, 2017), as will be described below.

2.2.1. Shale volume

Shale is a type of sedimentary rock that has three main attributes: clay minerals that constitute its structure, pore sizes and permeability values on a nanometric scale, and water adsorbed on its surface or between its sheets (Katahara, 2008). In a conventional petroleum system, the shale corresponds to the parent rock, where organic matter is stored and from which hydrocarbons are released, and can sometimes act as a seal, capable of generating an impermeable barrier that prevents the migration of fluids. In addition, shale can occupy the porous spaces of sedimentary rocks such as sandstones and carbonates, and this volume can be calculated from well logs. The most commonly used method for this calculation is the gamma ray technique; however, this method can present limitations when the rock contains clayey minerals that increase and overestimate the value obtained. Therefore, to perform this calculation, the method of Poupon and Gaymard (1970) was chosen, which used neutron porosity and density logs as input parameters. The resulting data was input into Techlog to generate the volume curve of shale, calculated from the following equation:

$$Vsh = \frac{\Phi_{NFL} - \Phi_{DFL}}{\Phi_{NMA} - \Phi_{DMA}} \tag{1}$$

where

Vsh = volume of shale in ft³/ft³
Φ_{NFL} = neutron porosity reading, 100% fluid
Φ_{NMA} = neutron porosity reading, 100% rock matrix
Φ_{DFL} = porosity density reading, 100% fluid
Φ_{DMA} = porosity density reading, 100% rock matrix

The subscripted terms Φ_N and Φ_D refer to the porosity values recorded by the neutron tool and density tool, respectively.

2.2.2. Effective and total porosity

Porosity is the property of rock that relates its porous or "void" volume (*Vporous*) to the total volume (*Vtotal*); that is:

$$\Phi total = \frac{Vporous}{Vtotal} \tag{2}$$

Porosity calculations were performed in Techlog from the neutron and density logs and using the generated shale volume curve as follows (Atlas, 1979):

$$\Phi_D = \left(\frac{\rho_b - \rho_{MA}}{\rho_f - \rho_{MA}}\right) \tag{3}$$

where

Φ_D = porosity density in ft³/ft³
ρ_b = apparent density in g/cm³
ρ_{MA} = density of the matrix (sandstone = 2.65 g/cm³; limestone = 2.71 g/cm³; dolomite = 2.87 g/cm³; anhydrite = 2.90 g/cm³; salt = 2.15 g/cm³)
ρ_f = density of the fluid (by default, a density of 1 g/cm³ is used, associated with sludge filtering)

To obtain all the parameters of Equation 3, Techlog makes the following considerations:

- If $\Phi_N \leq \Phi_D$, a limestone/sandstone combination is chosen
- If $\Phi_N > \Phi_D$, a limestone/dolomite combination is chosen

» If $\Phi_N > \Phi_D$, $2.91 \leq \rho_b \leq 3.5$ and $\Phi_E \leq 0.04$, anhydrite is chosen

where Φ_N = neutron porosity, obtained from log data, and Φ_E = effective porosity.

Finally, the following equation is used to determine the total porosity (Kamel and Mabrouk, 2003):

$$\Phi_{Total} = \frac{\Phi_N + \Phi_D}{2} \tag{4}$$

By substituting Equation 3 in 4, the total porosity is obtained in terms of density and neutron porosity (Atlas, 1979):

$$\Phi_{Total} = \frac{1}{2}\left[\Phi_N + \left(\frac{\rho_b - \rho_{MA}}{\rho_f - \rho_{MA}}\right)\right] \tag{5}$$

Equation 5 is then used to calculate the effective porosity (Φ_E) as follows (Tenchov, 1998):

$$\Phi_E = \Phi_{Total}\,(1 - V_{sh}) = \frac{1}{2}\left[\Phi_N + \left(\frac{\rho_b - \rho_{MA}}{\rho_f - \rho_{MA}}\right)\right](1 - V_{sh}) \tag{6}$$

2.2.3. Water saturation

Every reservoir stores a significant amount of water, which must be considered when estimating original oil volumes. This water (irreducible or connate) is stored in the formation, occupying porous spaces or stored in clays, and can be estimated from well logs and supported by correlations. Based on the petrophysical properties and lithological configuration of a reservoir, different models have been formulated for the calculation of water saturation. These models may or may not consider the amount of clay present and its distribution in the rock. The Archie model is the most used model globally but does not take into account the amount of clay present in the deposit, while the models of Simandoux (1963) and Schlumberger and Indonesia do. The Simandoux model was established experimentally with artificial sand and clay data, and the Schlumberger model is based on the Simandoux model and is less accurate due to not considering the cementation factor (Pinas and Acosta, 2019). In the present work, the Indonesia model (Equation 7) was used, as proposed by Leveaux and Poupon (1971), which assumes that clay is distributed in the formation in a random or dispersed way. This model, obtained from field data in Indonesia, seems to be the most complete:

$$Sw = \frac{1}{Rt}\left(\frac{\sqrt{aR_wR_{sh}}}{V_{sh}\sqrt{aR_w} + \Phi_{Total}^{\frac{m}{2}}\sqrt{R_{sh}}}\right)^{n/2} \tag{7}$$

where

S_w = water saturation, in percentage (%)
R_t = true resistivity of the formation (Ωm)
R_w = resistivity of brine water at the formation temperature (Ωm)
R_{sh} = average value of deep resistivity measured in shale (Ωm)
a = tortuosity factor
n = saturation exponent
m = cementation factor

2.2.4. Permeability

Permeability is one of the most important petrophysical properties of a reservoir since it measures the ability of a rock to allow the passage of a fluid through it. The fluid has a certain viscosity depending on the pressure and temperature at which it is found, and this property is also affected by the porosity of the rock, the tortuosity, the radius of the pores and the volume of clay (Ekpoudom et al., 2004).

It is possible to determine the permeability directly from rock cores obtained from the drilling of the well, but when such cores are not available, it is possible to obtain the value using well logs. For this calculation, the model of Coates and Dumanoir (1973) was used, which is based on a correlation of effective porosity and irreducible water saturation to obtain the permeability of the rock (Equation 8).

$$K = k_c * \Phi_E^4 * \left(\frac{1 - Swirr}{Swirr}\right)^2 \tag{8}$$

where
K = permeability in mD
k_c = empirical permeability constant, with a value of 10,000
S_{wirr} = irreducible or connate water saturation, in percentage (%)

The value of S_{wirr} is obtained by finding the lowest water saturation value in the curve generated with Equation 7, a value that is manually entered in Techlog to perform the permeability calculation with Equation 8.

3. Results

3.1. Lithostratigraphic correlation

The interval of interest identified for the fractured well corresponds to the zone in which hydraulic fracturing was performed, between 3775' and 3825'. The Monserrate Formation is identified as a sandstone rock interval with some clay intercalations whose resistivity values are high in areas with stored oil. Thicknesses within this interval were located where the gamma ray and resistivity values in the other wells correspond to the same or approximate values as those found in the fractured well. From these values, the correlation in Figure 3 was obtained, where the gamma ray logs of the wells are shown and the depths are plotted as the "length of the well" or *measured depth* (MD). From this correlation, one can identify that the Monserrate Formation is found at variable depths between 3400 'and 4450' for the wells considered in this study.

3.2. Petrophysical properties

Figure 4 shows the log data used and the petrophysical properties calculated for the fractured well. The intervals with drillings in the area of interest (3775-3780', 3794-3799' and 3811-3816') have gamma ray values below 130 gAPI and resistivities above 20 ohm*m. In addition, in the density and neutron logs, crosslinking is observed in the drilled intervals, indicating lower values in both logs. These data together reflect the presence of hydrocarbons stored in this area. From this information, shale volumes between 0 and 20%, effective porosities close to 16%, irreducible water saturations of 16% and permeabilities of 5 mD were found for the fractured well.

In the same way, the petrophysical properties of each well under study were calculated; Table 1 compares the estimated values for each parameter in the corresponding units.

These values are approximations of the calculations performed in Techlog and interpretation of the logs.

4. Discussion

Of the eleven initial wells (P1 to P11), P1 and P2 were discarded because these wells are too old and lack enough data.

From the results obtained, it was possible to identify two possible candidates for hydraulic fracturing: one was identified based on the lithostratigraphic correlation and the comparative petrophysical properties results obtained in Table 1; the second was identified by considering the above criteria together with production information and the drilling intervals in each well.

According to the results obtained in Table 1, the first candidate was well P6, whose petrophysical properties have values very similar to those of the fractured well.

In this case, we did not find the target formation in the well, so it was recommended to proceed with perforations and stimulation in the intervals identified in Figure 5 (4285-4290', 4303-4308' and 4322- 4327' in MD). Thus, stimulation should be performed in 15 ft of the Monserrate Formation located in well P6 at the aforementioned depths; the intent is to proceed

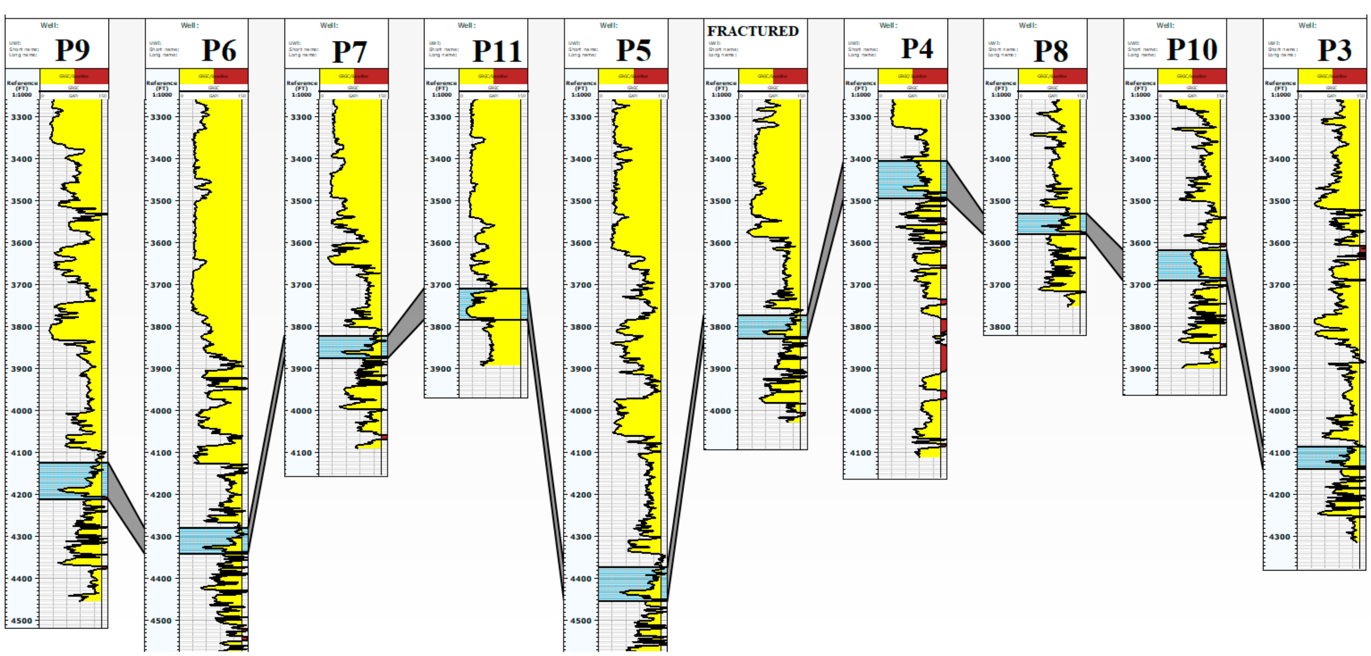

Figure 3. Lithostratigraphic correlation of the area of interest of the fractured well with wells P3 to P11, using gamma ray logs, oriented in the NS direction

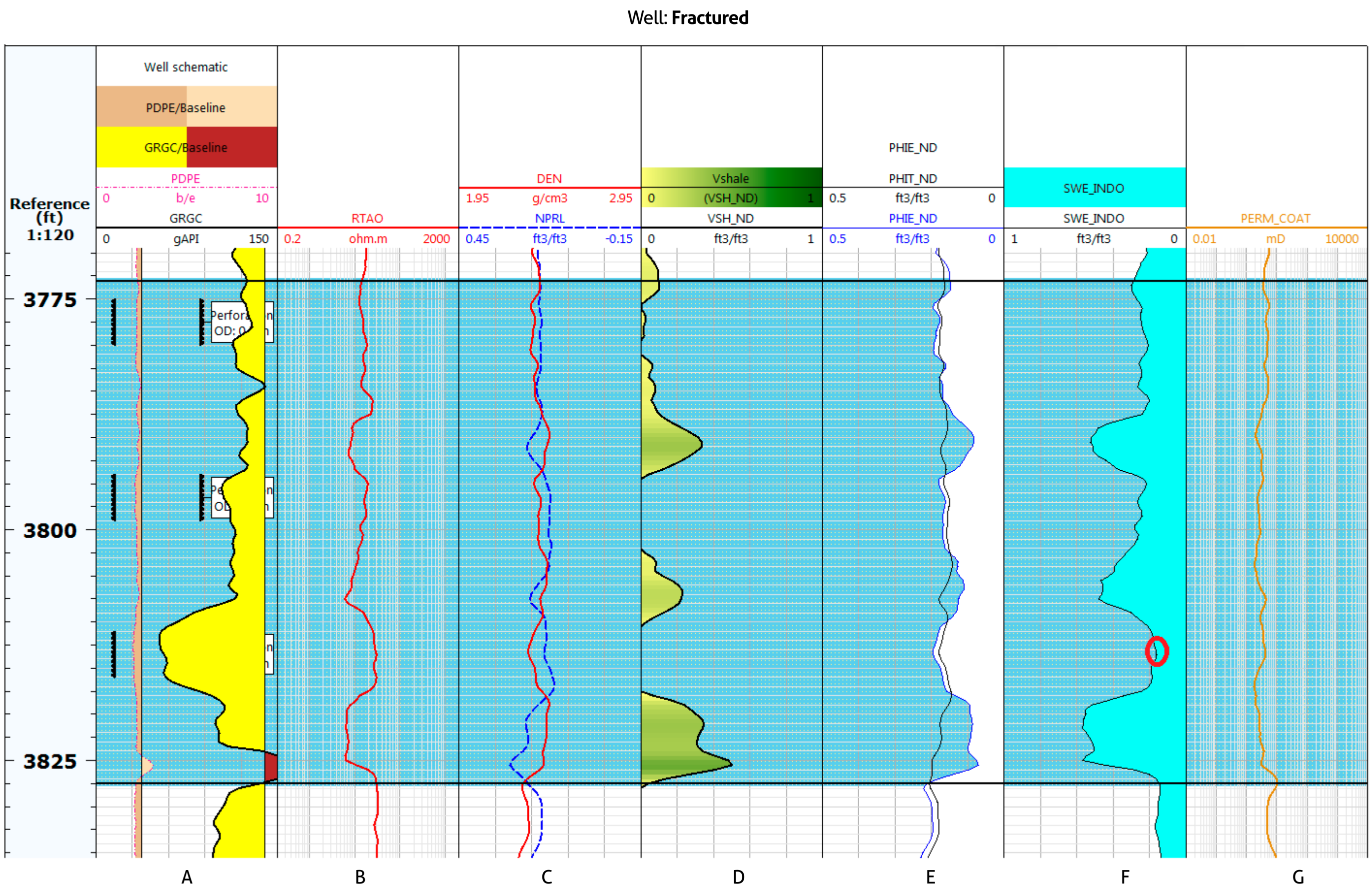

Figure 4. Petrophysical properties of the fractured well
a) gamma ray logs with drilled intervals; b) resistivity logs; c) density logs, in red, and neutron logs, in blue; d) volume of shale (Equation 1); e) total porosity (black, Equation 5) and effective porosity (blue, Equation 6); f) water saturation (Equation 7), where the red circle indicates the value of S_{wirr}; g) permeability (Equation 8). Data processed in Techlog.

Table 1. Values obtained for the petrophysical properties of the wells under study, comparing the fractured well with wells P3 to P11

Well\ID	Gamma ray	Resistivity	Neutron	Density	Shale volume	Total porosity	Effective porosity	S_{wirr}	Permeability
	gAPI	Ohm*m	ft^3/ft^3	g/cm^3	ft^3/ft^3	ft^3/ft^3	ft^3/ft^3	ft^3/ft^3	mD
Fractured	130	20	0.17	2.37	0.2	0.17	0.16	0.16	5
P3	105	25	0.15	2.4	0.2	0.17	0.16	0.2	3
P4	90	40	0.2	2.25	0.18	0.2	0.17	0.08	45
P5	118	35	0.15	2.45	0.2	0.15	0.12	0.21	1
P6	120	20	0.15	2.45	0.2	0.15	0.12	0.21	1
P7	97	30	0.15	2.3	0.16	0.17	0.15	0.13	10
P8	120	20	0.18	2.4	0.2	0.2	0.14	0.16	8
P9	110	50	0.11	2.47	0.3	0.16	0.09	0.23	1
P10	85	40	0.21	2.22	0.03	0.21	0.2	0.1	80
P11	30	200	0.3	2.05	0.04	0.43	0.42	0.035	6000

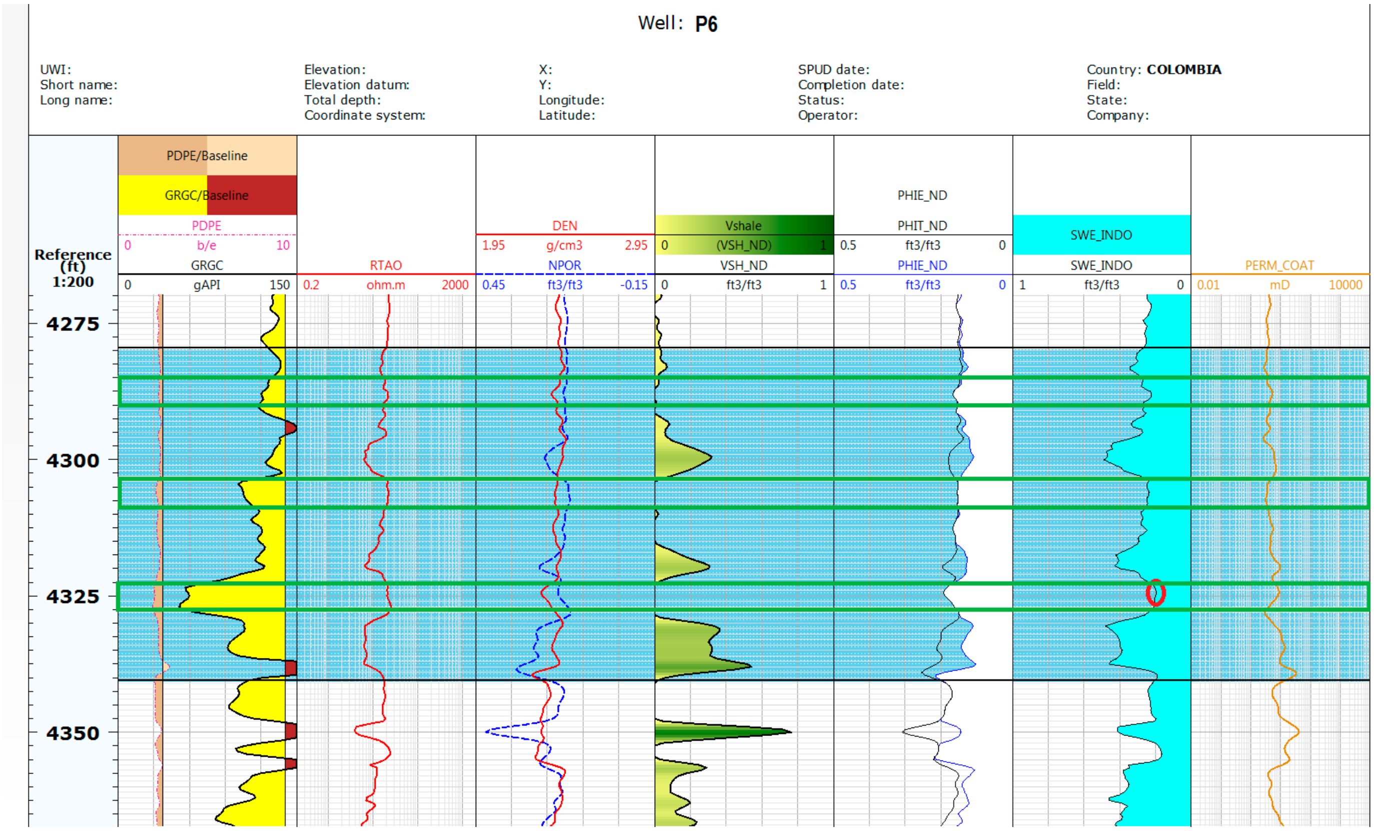

Figure 5. Petrophysical properties of well P6
a) Gamma ray logs with perforations intervals; b) resistivity logs; c) density logs, in red, and neutron logs, in blue; d) volume of shale (Equation 1); e) total porosity (black, Equation 5) and effective porosity (blue, Equation 6); f) water saturation (Equation 7), where the red circle indicates the value of S_{wirr}; g) permeability (Equation 8). Data processed in Techlog.

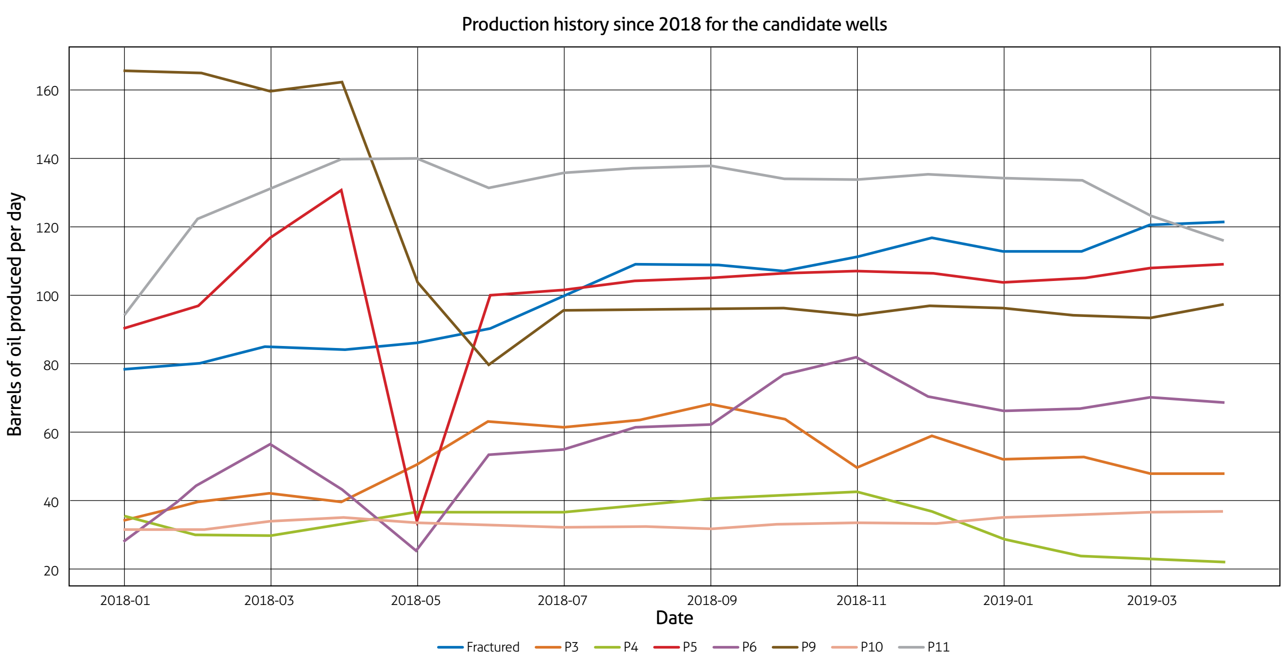

Figure 6. Production histories of the fractured well and wells P3, P4, P5, P6, P9, P10 and P11 in BOPD for 2018 and part of 2019

with a fracturing plan similar to that carried out for the fractured well but by adjusting the volumes of fluid and proppant according to the new depths of the intervals recommended in P6.

However, for the consideration of the second candidate, the following aspects were taken into account:

1. Wells P7 and P8 presented cementing problems; therefore, they were discarded by the operating company.
2. Of the remaining wells (P3, P4, P5, P6, P9, P10 and P11), an analysis of their production curves was performed (Figure 6) to determine their current state. With this information, wells that produce approximately 100 or more BOPD were discarded, that is, P5, P9 and P11. It was decided not to consider these wells because they already had high production, so our next analysis focused on wells P3, P4, P6 and P10.
3. For economic reasons, it was decided to discard wells that had no perforations in the correlated area of interest to avoid the need for new perforations in the area for subsequent stimulation. Therefore, wells P3 and P6 were discarded.
4. Finally, among the remaining candidates, the petrophysical properties of P4 and P10 were compared (Figures 7 and 8, respectively) to determine the best well in which to perform hydraulic fracturing. The following was found:
    - From the gamma ray logs (Figure 8a) and the shale volume calculations (Figure 8d), well P10 has cleaner reservoir rock, that is, rock with less clay and more homogeneous delimited thickness (3605-3692.5'), unlike

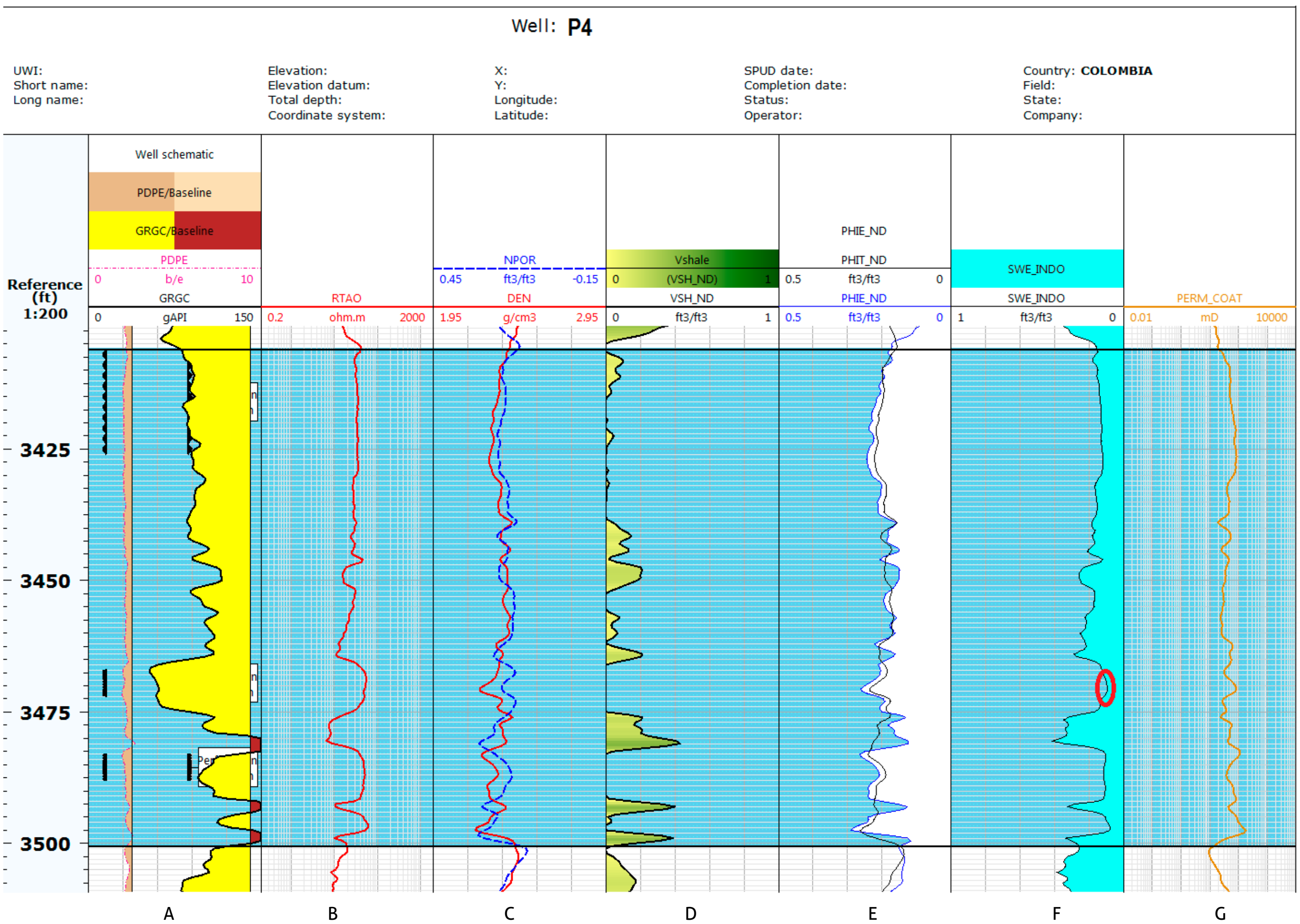

Figure 7. Petrophysical properties of well P4
a) gamma ray log with perforations intervals; b) resistivity logs; c) density logs, in red, and neutron logs, in blue; d) volume of shale (Equation 1); e) total porosity (black, Equation 5) and effective porosity (blue, Equation 6); f) water saturation (Equation 7), where the red circle indicates the value of S_{wirr}; g) permeability (Equation 8). The green boxes show the recommended intervals for hydraulic fracturing. Data processed in Techlog.

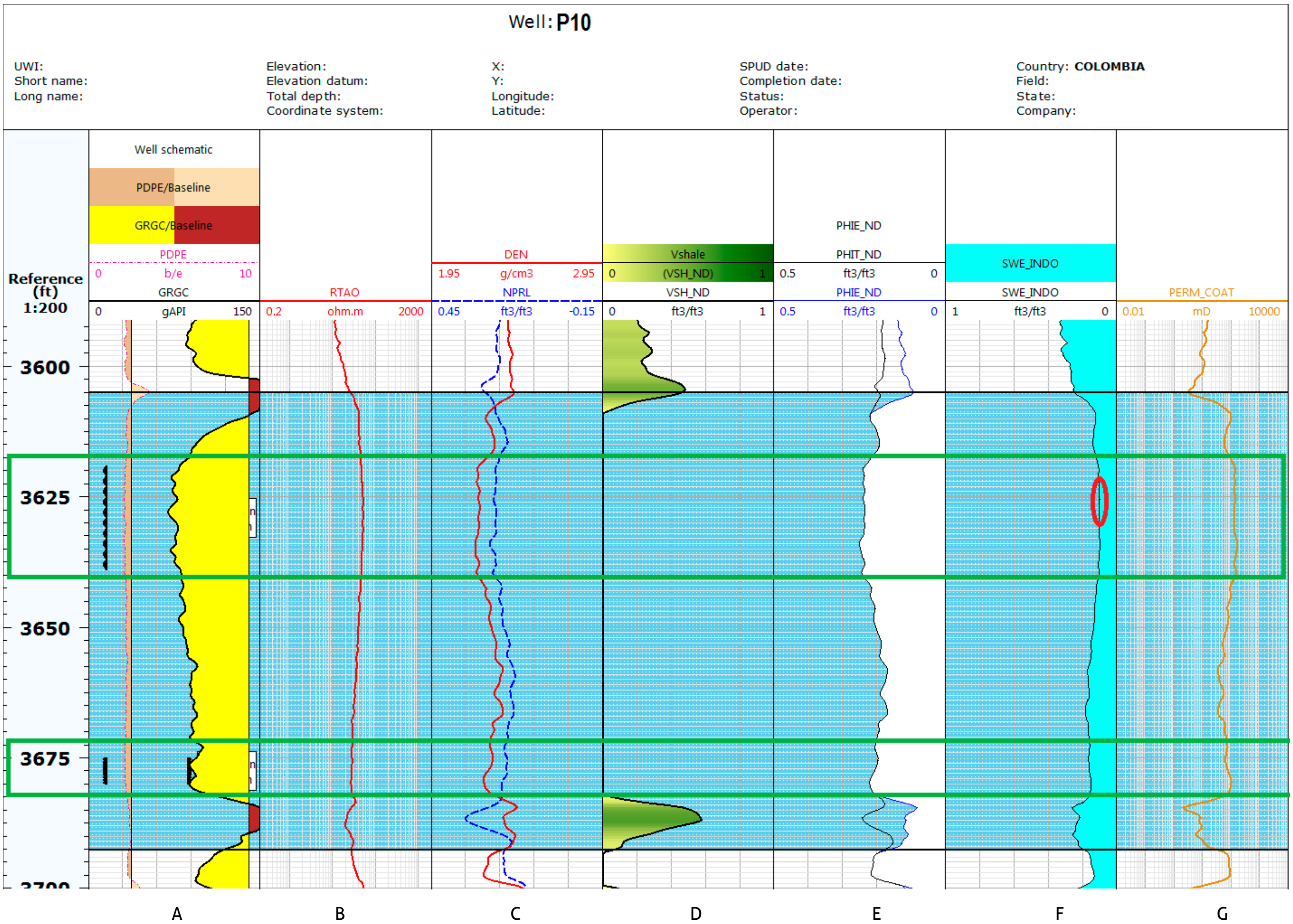

Figure 8. Petrophysical properties of well P10
a) Gamma ray logs with perforations intervals; b) resistivity logs; c) density logs, in red, and neutron logs, in blue; d) volume of shale (Equation 1); e) total porosity (black, Equation 5) and effective porosity (blue, Equation 6); f) water saturation (Equation 7), where the red circle indicates the value of S_{wirr}; g) permeability (Equation 8). Data processed in Techlog.

P4 (Figures 7a and 7d), which contains intercalations of clays in its reservoir in the indicated zone (3406-3500').

- The effective porosity in the perforations (3619-3639') is slightly higher in well P10 (0.23 ft ^{3}/ft^3; Figure 8e) than in well P4 (3406-3426', with 0.20 ft^3/ft^3; Figure 7e).
- The irreducible water saturation value is approximately the same in both wells (0.1 ft ^{3}/ft^3). In addition, in the interval of interest of well P10 (3605-3692.5'; Figure 8f), less water saturation is observed in the boreholes than in well P4 (Figure 7f).
- The 20 ft of perforations in well P4 (3406-3426') have permeability values between 50 and 100 mD (Figure 7g), while those in well P10 (3619-3639') have values between 100 and 110 mD (Figure 8g).
- According to the resistivity logs and the water saturation curve, depths greater than 3500' in well P4 have lower resistivity values (Figure 7b) and greater water saturation (Figure 7f) than in well P10 at depths greater than 3690' (Figures 8b and 8f). Greater water saturation below the area of interest could represent problems due to *basic sediments and water* (BS&W), water coning and/or an increase in production in the future if stimulation is performed in well P4.

Therefore, as a final decision, it was determined that to replicate the successful work in the fractured well and improve the production of the new well, the optimal zone to execute new hydraulic fracturing is in well P10 in the perforations intervals in the Monserrate Formation (i.e., 3619-3639' and 3675-3680' in MD; Figure 8). At the time of this study, well P10 produces an amount of oil approximately equal to that of the fractured well prior to stimulation. Additionally, the values obtained for the petrophysical properties of well P10 are better than those of the fractured well (lower shale volume, greater porosity, greater permeability, and lower water saturation), and the intervals are at a lower depth. Given these findings, we could expect that stimulation in well P10 would produce similar or even better results than those obtained in the fractured well.

5. Conclusions

With the use of gamma ray and resistivity logs, it was possible to correlate the interval of interest of the fractured well (3775-3825') with the other wells under study based on the identification of repeated patterns in these logs.

Based on the petrophysical calculations, production histories and current conditions of each well under study, the optimal zone to perform new hydraulic fracturing was recommended based on technical criteria and updated information.

The first candidate (P6) presents log data and petrophysical properties most similar to those of the fractured well, according to which hydraulic fracturing in the intervals 4285-4290', 4303-4308' and 4322-4327' could be successful.

The optimal zone to perform new stimulation by hydraulic fracturing, considering the economic and historical aspects of production, corresponds to the intervals of 3619-3639' and 3675-3680' in MD for well P10.

A new hydraulic fracturing undertaking would increase productivity, that is, would enable the production of more barrels per dollar spent on the energy required to lift them.

The approach used in this study can be applied to more wells, even in other fields, which would allow the evaluation of different options to increase the production of oil wells through the use of hydraulic fracturing.

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