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Extended Limit Tests for Improved Management and Initial Dynamic Reservoir Characterization

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Abstract

The objective of this work is to analyze the pressure transient behavior in long or extended testing times to detect reservoir limits and to guarantee an optimal reservoir dynamic characterization that allows to understand, the real behavior of the producing formation since the beginning of its productive life, as well as ensuring timely decision-making.

For this analysis, we considered some Extended Limit Tests (ELT) in exploratory or wildcat wells and currently producing wells in developed fields, from which we found the main well productivity associated parameters, an approximation of the optimum number of wells, drainage radii, estimated reserves to recover and the detection of reservoir limits and heterogeneities. The responses obtained were compared then, the associated problems and the causes that originated them from the design, execution and finally, during the interpretation of the Pressure Transient Analysis (PTA) were identified. Additionally, the present paper also attempts to propose a practical approximation for well drainage and investigation radii considering the nature of fractures in carbonates.

The importance of this work lies in improving the initial characterization of reservoirs through the analysis of Extended Limit Tests (ELT) for reaching a greater radius of investigation; correspondingly, it is intended to implement an appropriate exploitation scheme (fit for purpose) for each field according to their characteristics and behavior shown for a good reservoir management and Optimal Number of Wells (ONW) to increase the recovery factor, risk mitigation and future investments assurance.

Introduction

One of the most important factors when a new field is discovered is the acquisition of enough information for formation evaluation, determination of the type of fluid and to predict more accurately its future behavior. For this, it is necessary to take information from the discovery and during the delimitation of the field with the main objective of appraising better the reservoir from the beginning of its development to make improved decisions and take advantage of the characteristics of the rock-fluid system and the operational conditions to ensure its optimal exploitation and maximize the recovery factor.

Within the range of information to be gathered during this stage, such as special geophysical logs, cores, PVT, production testing, production logs, well tests, among others stand out. Specifically, the well tests represent one of the most valuable sources of information that we can count on, since they allow us to know a large portion of the reservoir, as well as the determination of its properties and the detection of heterogeneities and limits of the reservoir. However, the above is a function of the execution time of these, which in turn depends on the transmissivity and diffusivity of the system, in order to obtain the aforementioned information and properly characterize the reservoir since the beginning of its exploitation through Extended Limit Tests (ELT).

Pressure Transient Analysis (PTA) through Extended Limit Tests (ELT)

The primary goal of Pressure Transient Analysis (PTA) through Extended Limit Tests (ELT) is to obtain a better reservoir dynamics description in order to evaluate the initial pressure-production behavior, guarantee a greater radius of investigation within the formation, to get well productivity parameters, to compute a well drainage radius and the associated porous volume, to detect reservoir limits in pseudosteady state (faults, seals, facies and stratigraphic changes) and/or steady state (aquifer and gas cap) to be able to estimate the size of the reservoir, which is aimed to have a good approximation of the hydrocarbon volumes in place and generate production profiles based on reliable analyzes, that will reduce the risk in investments for the development of the field (to find the Optimal Number of Wells (ONW) to be drilled and completed, and to estimate a probable volume of hydrocarbons to be produced for the design and construction of surface production facilities, with the necessary capacity to ensure efficient production management, as well as the acting drive mechanisms and the visualization of secondary and/or EOR processes more convenient and when they should be implemented).

Below we present some cases to show the benefits of PTA through ELT in exploratory wells and developed fields. The first case of study is about an exploratory well "A" from a carbonated formation of Upper Cretaceous age, producing 37.9°API light oil at 5,336 m in TVD, with an average effective porosity of 8%, an initial water saturation of 26%, a GOR of 120 m^3/m^3, the reservoir temperature is 140.5°C, the original pressure was estimated to be 987 kg/cm^2 (14,035 psi) and the bubble point pressure is 185 kg/cm^2 (2,630 psi).

To this day, there have been three closures of a considerable duration; the first one carried out in February 2017 during the completion of the well, a well test was performed in order to know the reservoir potential through a pressure build-up taken with DST (217 hours shut in time), where it can be observed that the response of the pressure derivative function was modeled as a semi-closed system with three flow limits and a double porosity system with an effective permeability to oil of 20.8 md and an average reservoir pressure of 955.5 kg/cm^2 (13,587 psi), which taken to the reservoir reference plane gives a pressure of 986 kg/cm^2 (14,021 psi). During the production testing, four different fixed chokes were used (1/8, 1/4, 3/8 and ½ in.) with a varying production from 845 to 3,744 bd of oil and 0.42 to 1.7 MMscfd.

Subsequently, in November 2017, an ELT was performed after a shut-in period of 9 months due to lack of infrastructure for production handling. Then, a 500 hours pressure build-up was carried out, where a dual-porosity response was identified again, with an effective oil permeability of 67.9 md and a flow capacity of 10,800 md-ft, the skin factor was -1.87, the fracture storage coefficient (ω) was evaluated to be 0.0232 and the interporosity flow coefficient (λ) was 2.34E-06 (Figure 1).

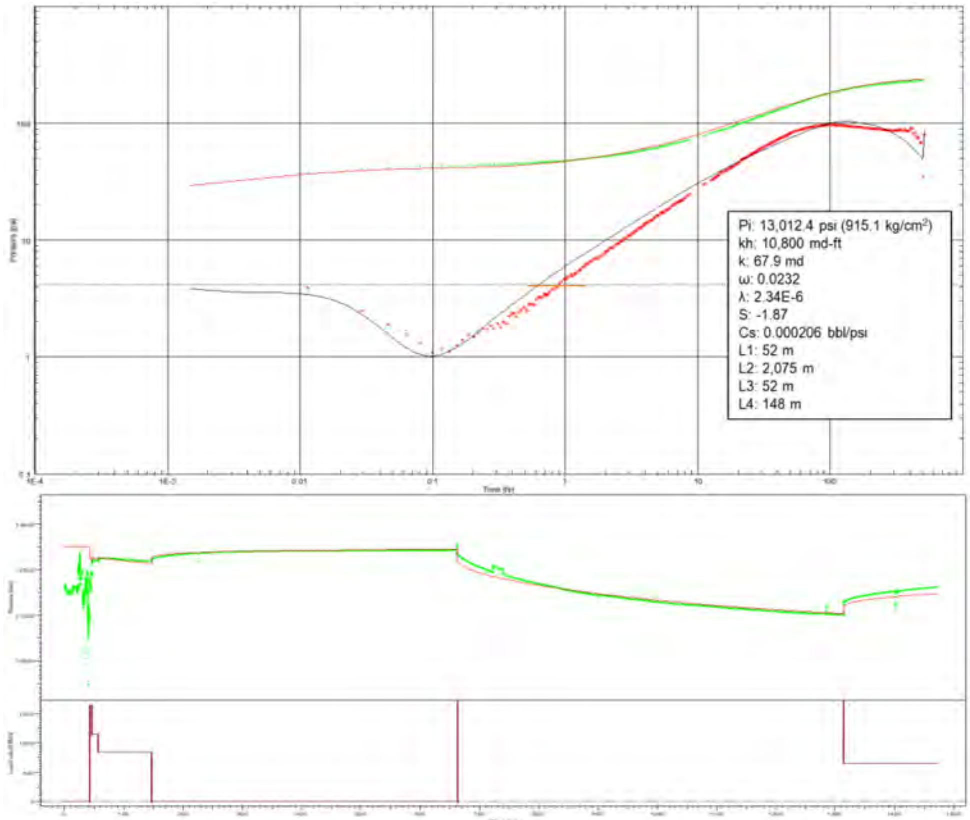

Figure 1—A 500 hours pressure build-up test.

In the Late Time Region (LTR) from the pressure derivative plot, it is observed an apparent "radial flow" with less effective oil permeability, however, if we look carefully, we could identify that the pressure derivative data started to deviate downwards with a smooth slope, so, when we correct the pressure build-up by equivalent production time (Agarwal 1980), it is clearly seen that the pressure derivative shows a typical behavior associated to a closed system (Figure 2).

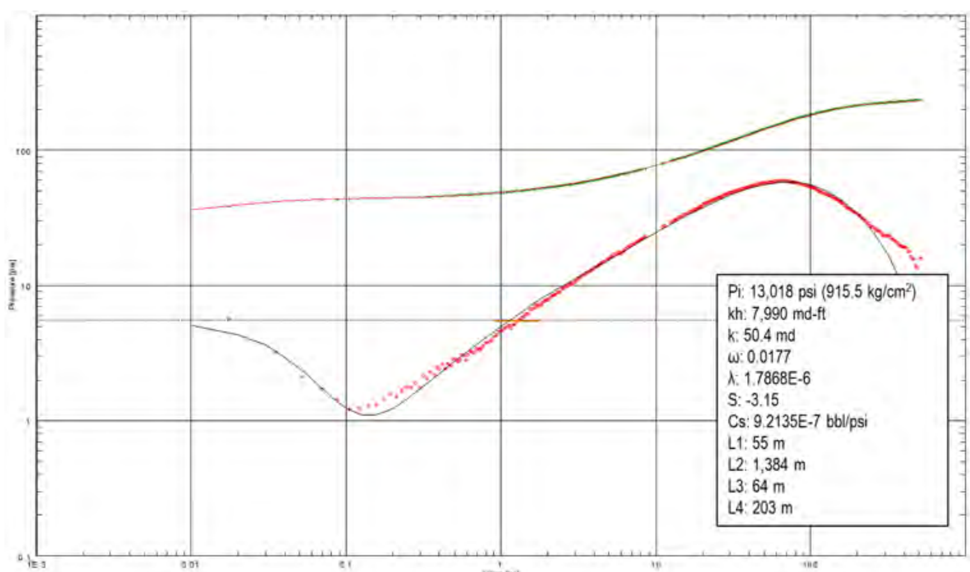

Figure 2—The 500 hours pressure build-up test corrected by equivalent production time.

According to the information of the static model and the analysis of fractures available, it was determined that the permeability decreases as the radius of investigation becomes greater and moves away from the area near the well, therefore, this responds to the discontinuity of the fractured medium far away the well (Figure 3). It is also important to mention that the average reservoir pressure at this shut-in was 915 kg/cm^2 (13,011 psi), which, when taken to the reference plane yields a value of 936 kg/cm^2 (13,310 psi).

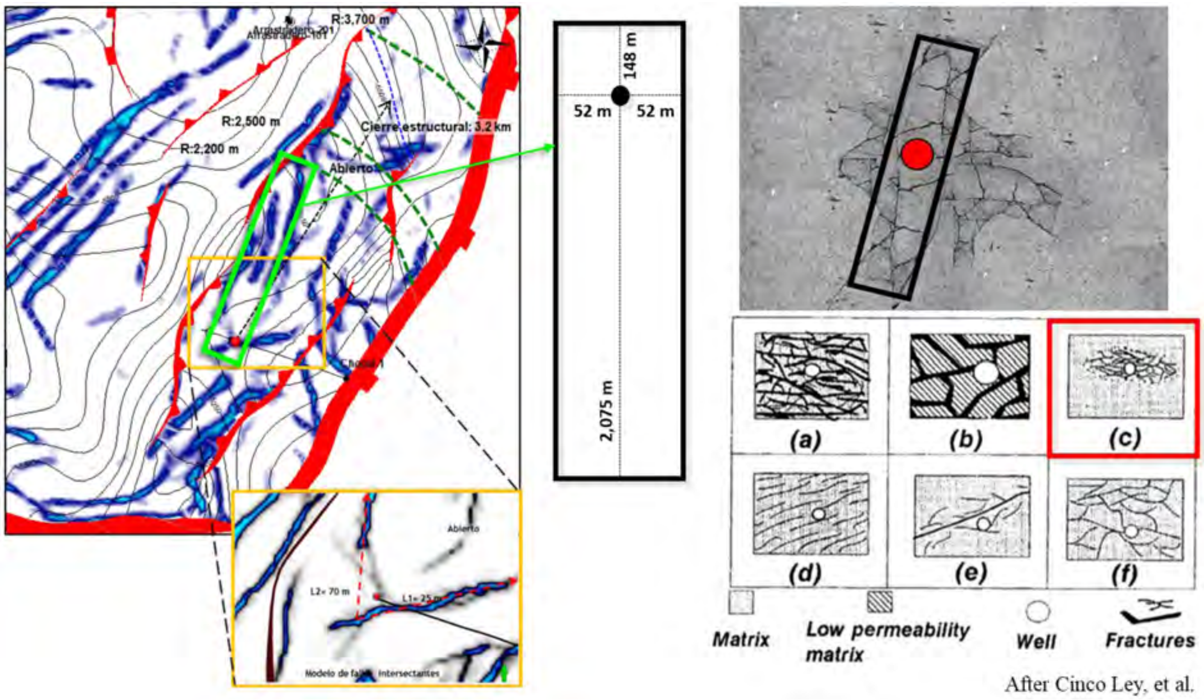

Figure 3—Interpreted discontinuity of the fractured medium far away the well

Because in a matter of days, the water cut production began to increase abruptly (up to 50%) and the flowing bottom-hole pressure dropped significantly, the decision to choke back the well to 10/64 in. was made, being the optimum diameter for this well for the reservoir exploitation, allowing to keep the water cut constant at values below 25% (Figure 4).

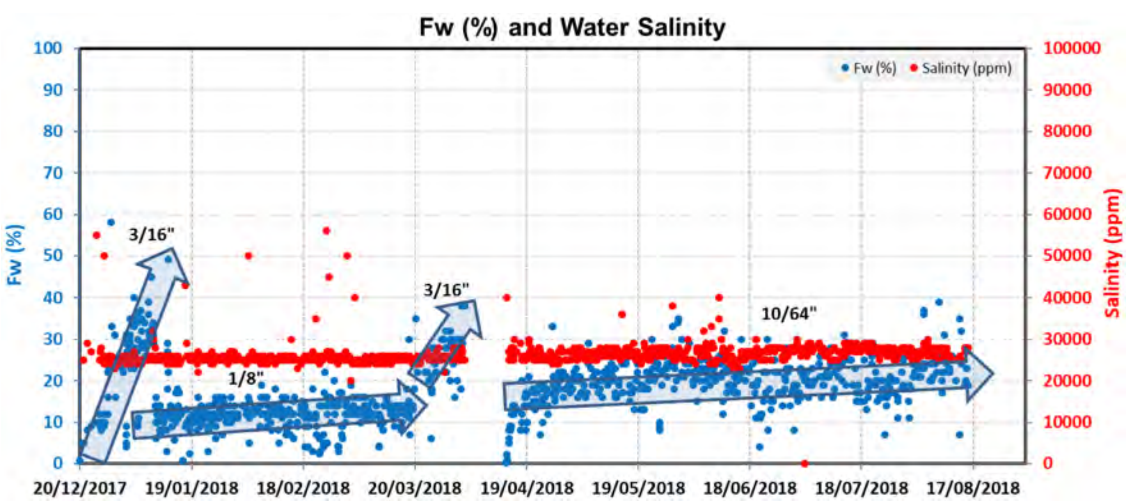

Figure 4—Water cut production and salinity.

Then, a third shut-in was made in April 2018, whose pressure derivative response was adjusted with a semi-closed system with three limits, an effective oil permeability of 17.6 md and an average reservoir pressure of 830.2 kg/cm^2 (11,805 psi), which taken to the reservoir reference plane yield 869 kg/cm^2 (12,357 psi). The pressure response is affected by humping effects and phase segregation, it is also displayed qualitatively that the behavior is very similar to the previous pressure build-ups (Figure 5), which is indicative of a system with low contribution and is corroborated by the diminution of static pressures registered during each shut in made since the completion of the well, where it has been observed that the reservoir pressure has fallen approximately 120 kg/cm^2 (1,706 psi) with a cumulative production of 0.532 million barrels of oil; besides the condition of production of low salinity formation water that acts as "bad water", which has the characteristic of decreasing oil cut production without supporting the pressure.

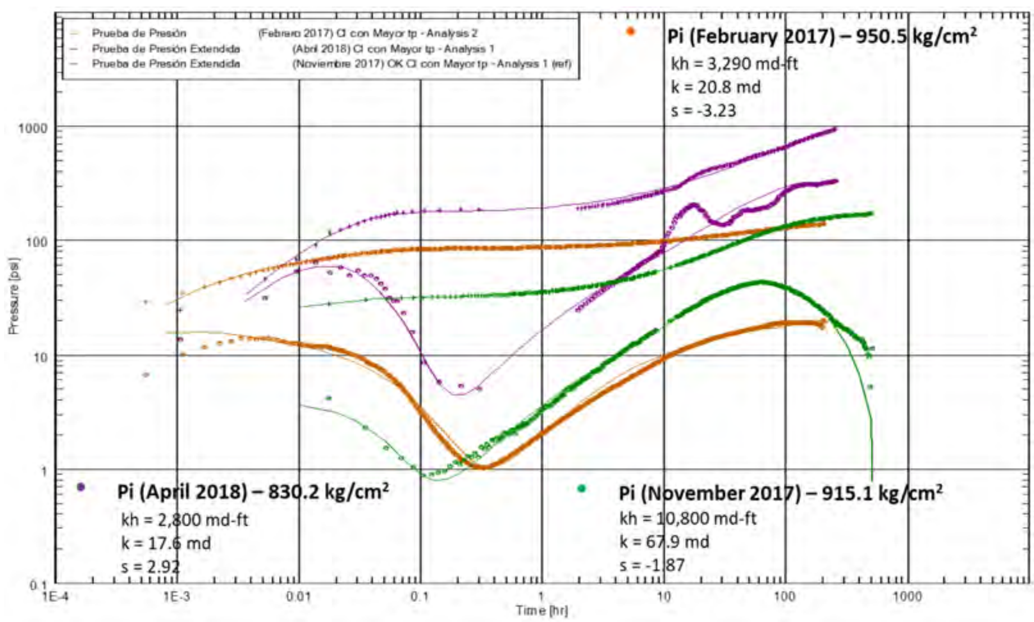

Figure 5—Pressure build-up tests in the field.

Regarding the pressure drawdowns, the results obtained in the pressure build-up tests are very similar to those observed during the flow periods (Figure 6). The pressure derivative behavior exhibited the characteristics of a pseudo-steady state. From the slope obtained (-0.056 psi/hour) after 11,842 hours flowing the well through a 10/64 in. choke (Figure 7), the calculation of the porous volume associated to the well was performed using the Jones (1957) method, defining the porous volume (35.85 million STB) and the drained area (1.48 km^2); based on this information, it is calculated that the drainage radius of the well is 126 m, with an overall investigation radius of the test of 1,836 m and finally, the estimated hydrocarbon volume in situ was calculated to be 26.2 million STB.

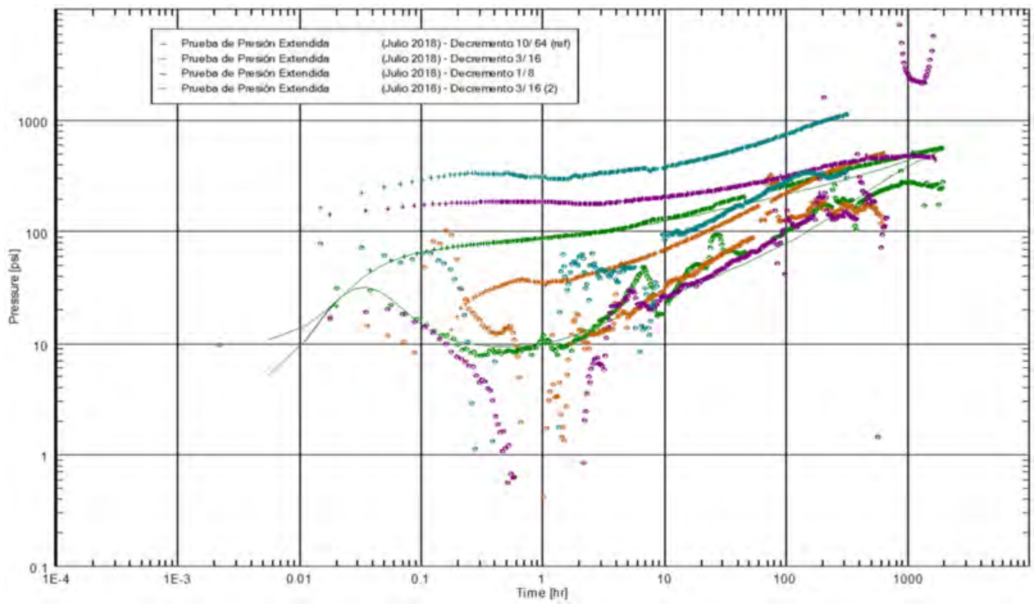

Figure 6—Pressure drawdown tests in the field.

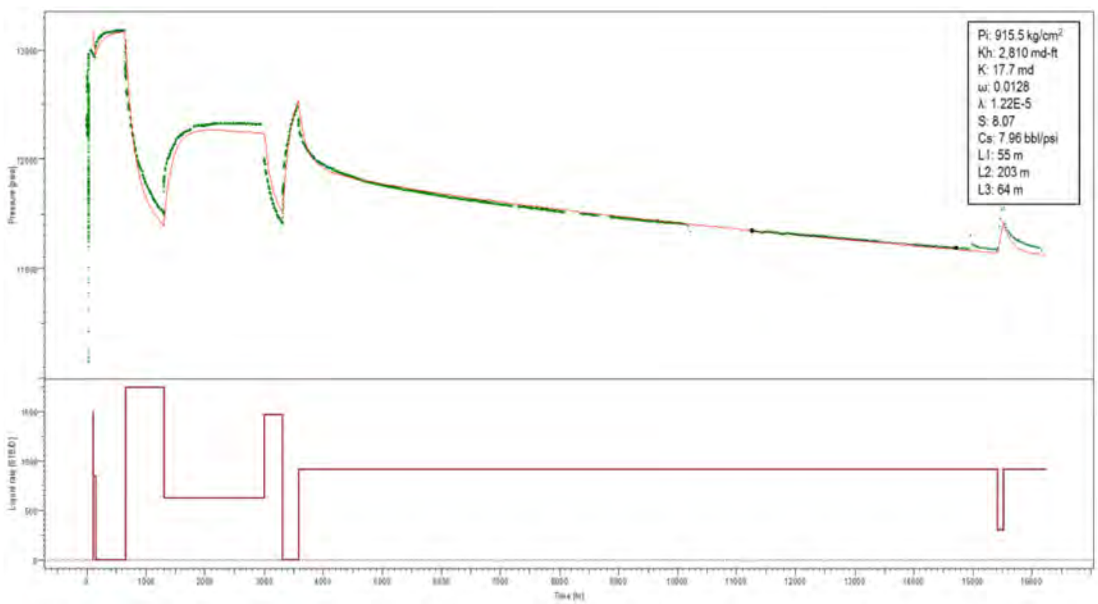

Figure 7—ELT history simulation.

According to the ELT, the reservoir was evaluated to be small and the well was determined not be capable of supporting chokes with a diameter greater than 10/64 in., since the reservoir pressure drops sharply, and the water cut increases exponentially. Due to the appraisal acquired through the ELT, the drilling of more wells in the reservoir was avoided, which in case of having been done shortly after completing this well, given the initial potential shown, would have been unsuccessful; thus the ELT helped to generate added value and optimizing costs for a greater profitability.

Well "B" was an appraisal well drilled in a deep carbonate retrograde-condensates gas reservoir recently discovered at 6,500 m in TVD from Cretaceous age. The effective average porosity is 5.7% and the initial water saturation is 18%. The original reservoir pressure is 1,200 kg/cm^2 (17,064 psi) at 161°C, the dew-point pressure is 598 kg/cm^2 (8,507 psi), the GOR is 1,485 m^3/m^3 while the Condensate-Gas Ratio (CGR) is 127 bls/MMscf.

An ELT through a 143 hours pressure build-up was performed to appraise the reservoir potential. The pressure response was modeled as an infinite radial composite reservoir with an average reservoir pressure of 1,180 kg/cm^2 (16,775 psi), a flow capacity of 837 md-ft, a permeability of 7.5 md, the skin factor is 5, the mobility ratio and the diffusivity ratio are 3, the inner radius was 183 m, while the radius of investigation was estimated to be 500 m, respectively (Figure 8).

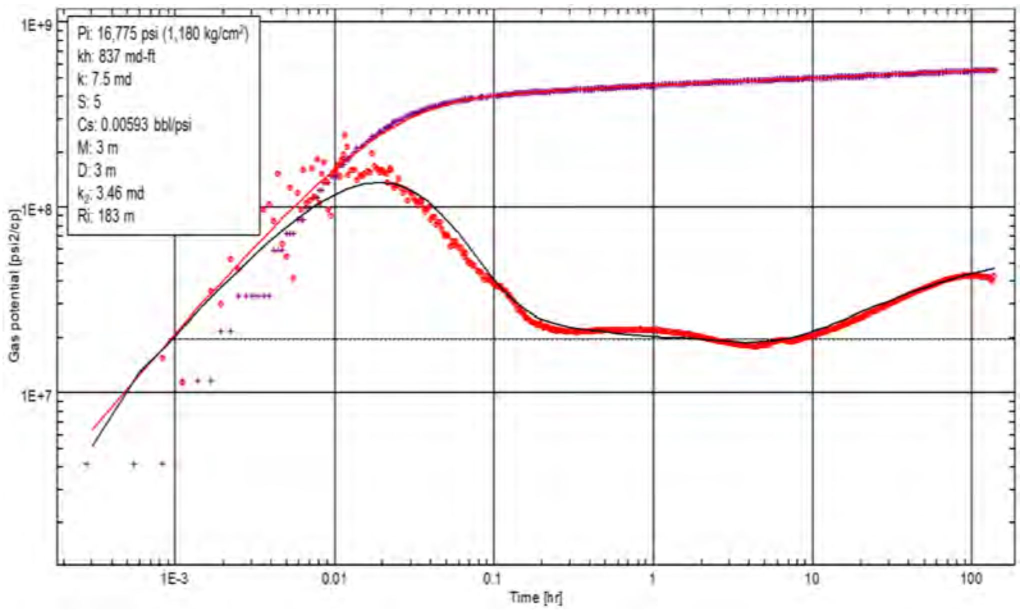

Figure 8—A 143 hours pressure build-up test.

Well "B" did not present a strong pressure drop (174 kg/cm^2 or 2475 psi) enough to reach the dew-point pressure and having condensation within the formation (Figure 9); so, the radial composite model was adjusted to interpret a facies change 183 m far the well. The reservoir rock is a reef trap; however, the low effective porosity and permeability values are mainly due to the rock compaction at that depth (Figure 10).

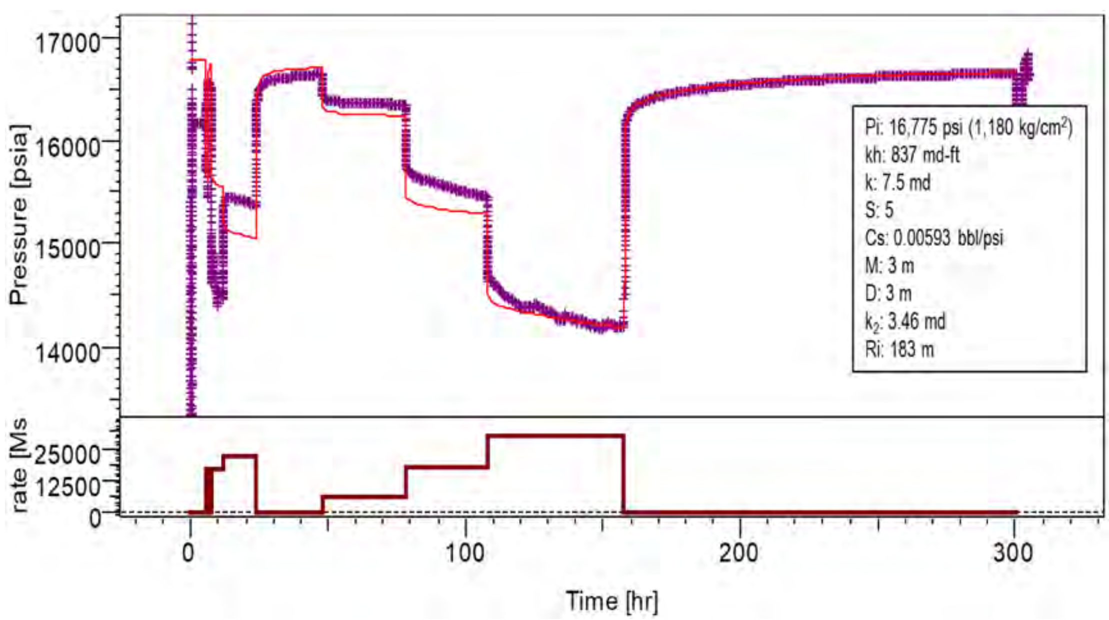

Figure 9—ELT history simulation.

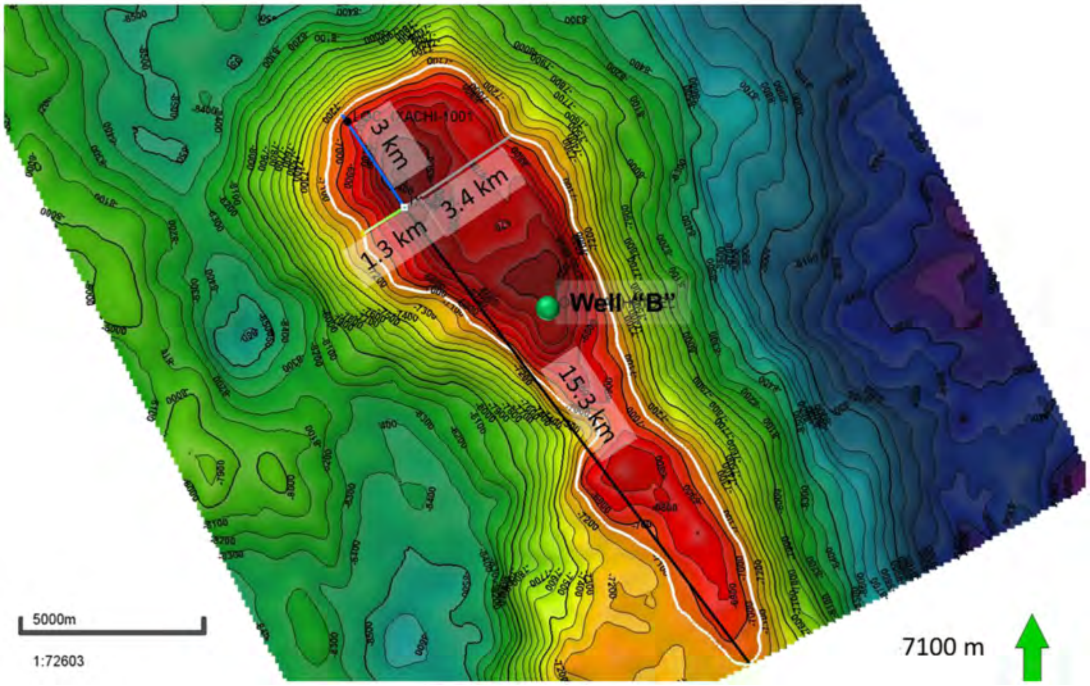

Figure 10—Structural configuration of the reservoir showing the position of well "B".

Well "C" was the discoverer of an anticline structure associated to another field under exploitation. The area of interest is located in carbonated Upper Cretaceous formations at 4,650 m in TVD of an average effective porosity of 3% and an initial water saturation of 34%, producing 41°API volatile oil, the reservoir temperature is 145.5°C and the original pressure was estimated to be 483.5 kg/cm^2 (6,875 psi), while the bubble point pressure is 292 kg/cm^2 (4,152 psi) and the GOR is 418 m^3/m^3. An ELT was performed in order to characterize the reservoir and estimate the *in situ* hydrocarbon volume through a large drawdown test (2,700 hours). The well started to produce formation water gradually since the beginning of production, reaching 10% at the end of the ELT.

The pressure response was modeled as a homogeneous reservoir with sealing faults (closed system), with an average reservoir pressure of 441.6 kg/cm^2 (6,280 psi), a flow capacity of 761 md-ft, an effective permeability to oil of 2.55 md, the distance to the faults are 170, 370, 2,230 and 540 m, respectively. When comparing the two drawdowns in the log-log plot (Figure 11), 794 hours (purple line) and 2,700 hours (blue line), it can be seen that at early times, the same response is obtained in the pressure derivative of the evaluated periods, observing the radial flow approximately at 8 hours of flow. In addition, it is also evident that the test was affected by humping effects and phase segregation.

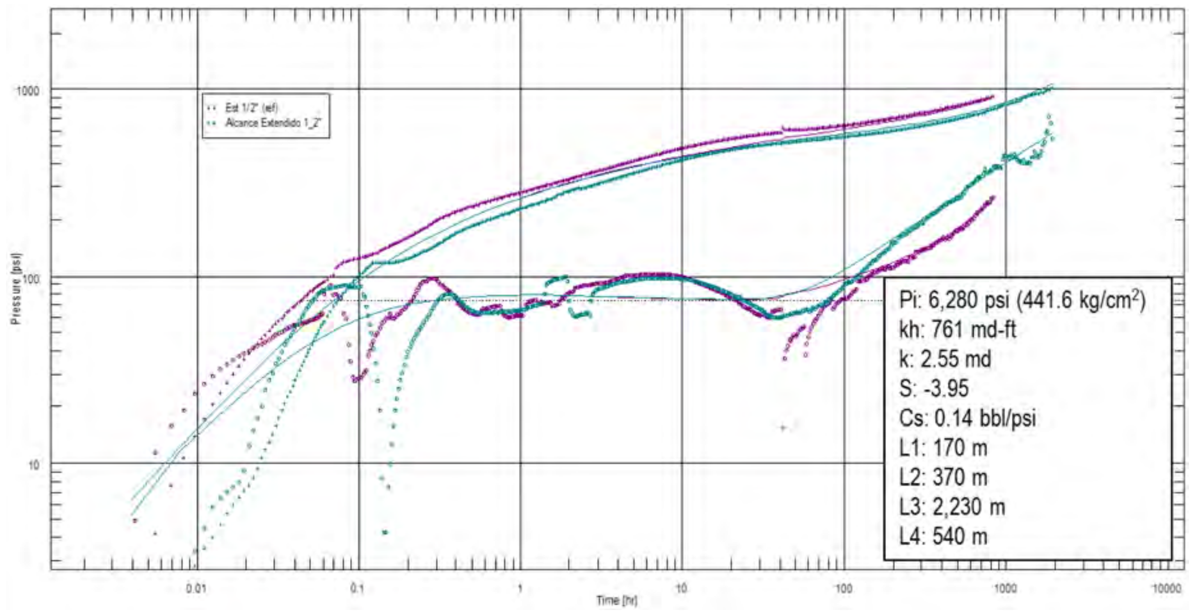

Figure 11—Pressure drawdown tests.

The interpretation of the reservoir limits indicates that the structural trap closes against faults, moreover, there is a condition in which the structure has a very steep slope to the Northeast, producing a closed system due to the spill point (Figure 12).

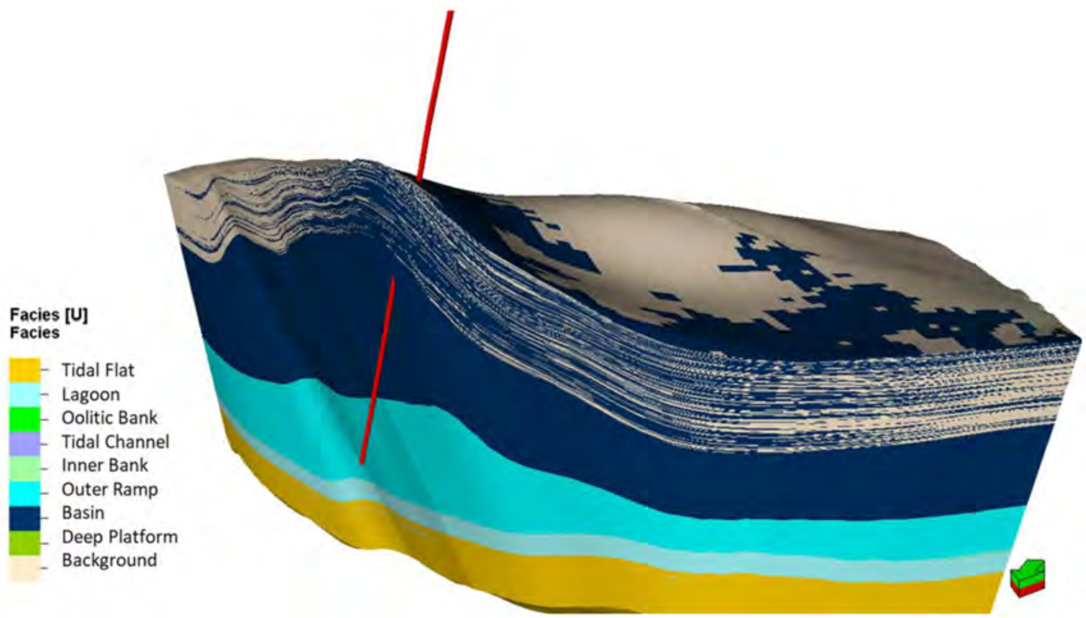

Figure 12—Structural position of well "C".

The calculation of the porous volume associated to the well was 51.4 million barrels, the radius of investigation was of 1,383 m and the estimated hydrocarbon volume in situ was estimated to be 20.2 million barrels, accordingly, the original oil reserves were estimated to be 4.84 million barrels, considering the EUR of the field (24%), see Figure 13 Once again, because of the highly valuable information related to the reservoir size acquired through ELT, it was possible to avoid the unnecessary drilling of additional wells that were originally planned.

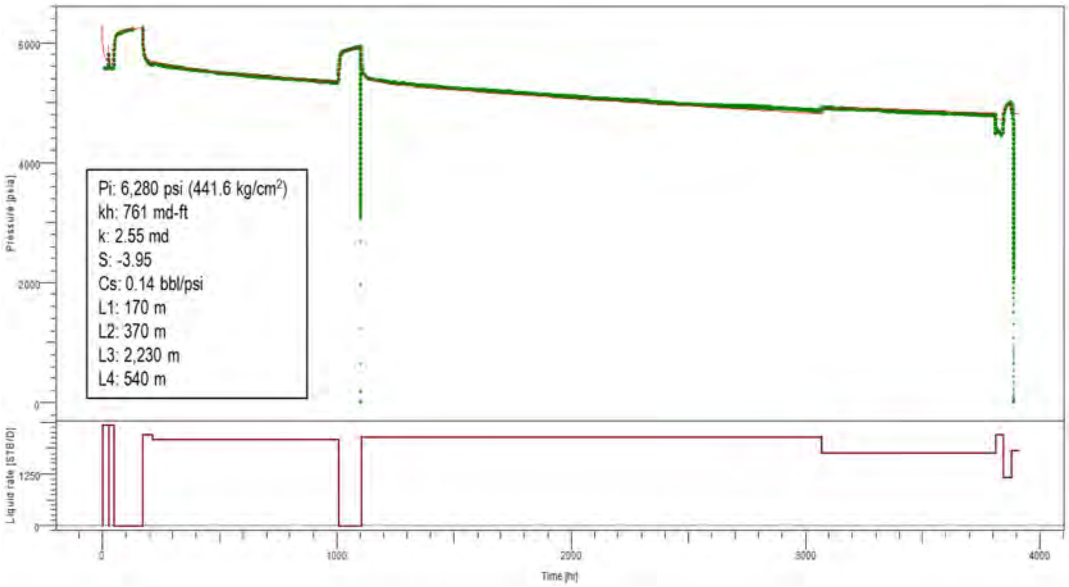

Figure 13—ELT history simulation.

The well "D" is another wildcat producer of retrograde-condensates gas at 5,470 m in TVD, completed in open-hole in carbonates of Upper Jurassic Kimmeridgian age, with natural fractures or dissolution open to flow that have an important influence on the productivity of the well. The average reservoir pressure is 809.7 kg/cm^2 (11,514 psi) and the reservoir temperature is 183.1°C, the dew-point pressure is 420.7 kg/cm^2 (5,982 psi). The measured production was 1,342 bd of condensates, 14.05 MMscfd of gas and 178 bd of water through a 3/8 in. choke size.

An ELT was performed through a 105 hours pressure build-up, where the obtained response was modeled as a homogeneous reservoir with a limited entry well with changing storage and rectangular shaped-limits (closed system), with an average reservoir pressure of 802 kg/cm^2 (11,406 psi), a flow capacity of 20,800 md-ft, an effective permeability to oil of 85.5 md, the skin factor resulted in 30, while the k_z/k_r is around 0.033 and the distance to the faults are 66, 470, 694 and 3,950 m, respectively (Figure 14).

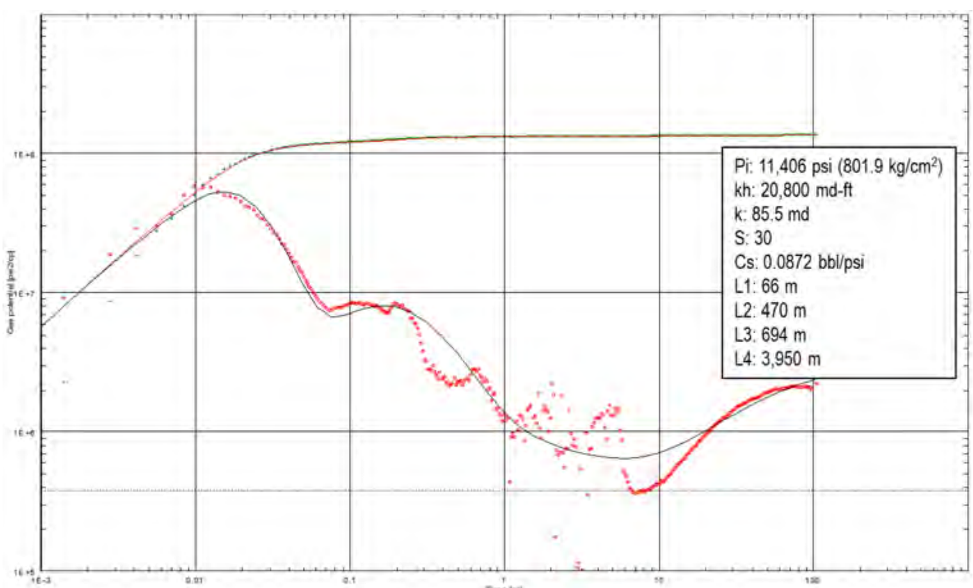

Figure 14—A 105 hours pressure build-up test.

The high value of skin factor is due to hemi-spherical flow (partial penetration related to the position of the well with respect to the entire reservoir) and also strong formation damage, because of several mud losses recorded during the drilling of the borehole; moreover, the addition of viscous sludges of fine and medium-grain sized calcium carbonated sealing material used to control or avoid fluid losses (Figure 15). Though, the inertial flow produced by the limited entry effects could affect the pressure response, resulting in an overestimation of the true value of effective permeability and the calculated distance to the limits, that is why, we recommend to reevaluate the origin of the partial penetration in order to reduce the skin through the addition of more intervals to perforate and then, to perform another well test.

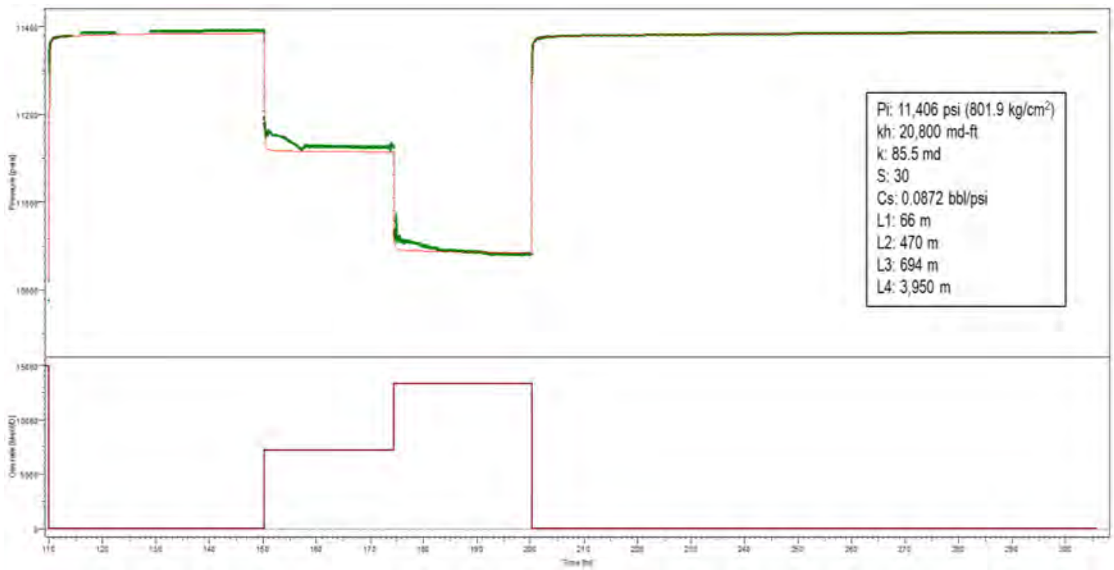

Figure 15—ELT history simulation.

Well "E" was the discoverer of a sequence of sandstones of fluvial channel environment of Upper Miocene age producing different type of fluids, from heavy oils (shallow sandstones) to light oils (deep sandstones). An ELT was performed to evaluate the first sand body (the deepest one) at 3,500 m in TVD; this sandstone produces 36°API light oil with a GOR of 289 m^3/m^3, the reservoir temperature is 94.6°C, the original reservoir pressure is 324 kg/cm^2 (4,607 psi) and the bubble point pressure is 312.2 kg/cm^2 (4,439 psi), see Figure 16.

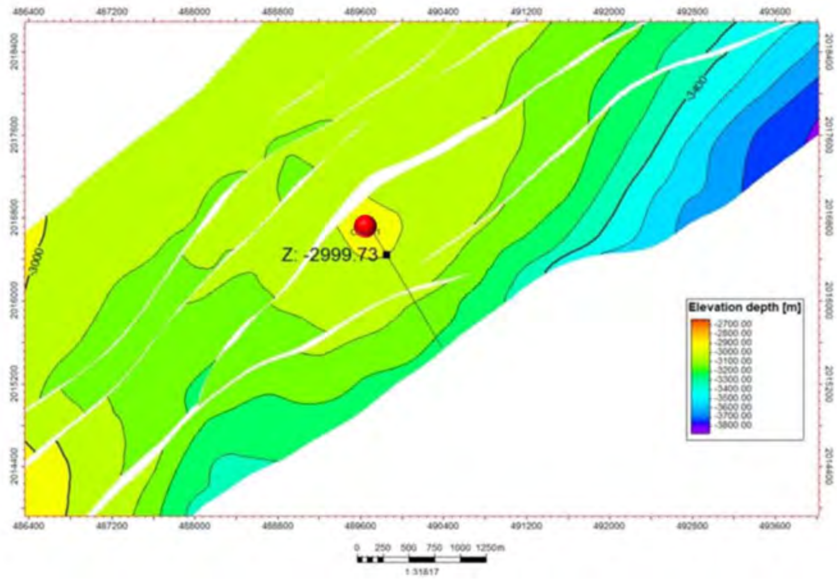

Figure 16—Structural configuration showing the position of well "E".

A 100 hours pressure build-up test was carried out in the first sandstone in order to characterize the reservoir. The adjusted model was a homogeneous reservoir and intersecting faults, with an average reservoir pressure of 319 kg/cm^2 (4,539 psi), a flow capacity of 24,300 md-ft, an oil effective permeability of 617 md, the skin factor was 8.2 and the intersecting faults were evaluated to be at 395 and 419 m, respectively. The radius of investigation was calculated to be 642 m; however, the response was affected by some noise and humping effects (Figure 17).

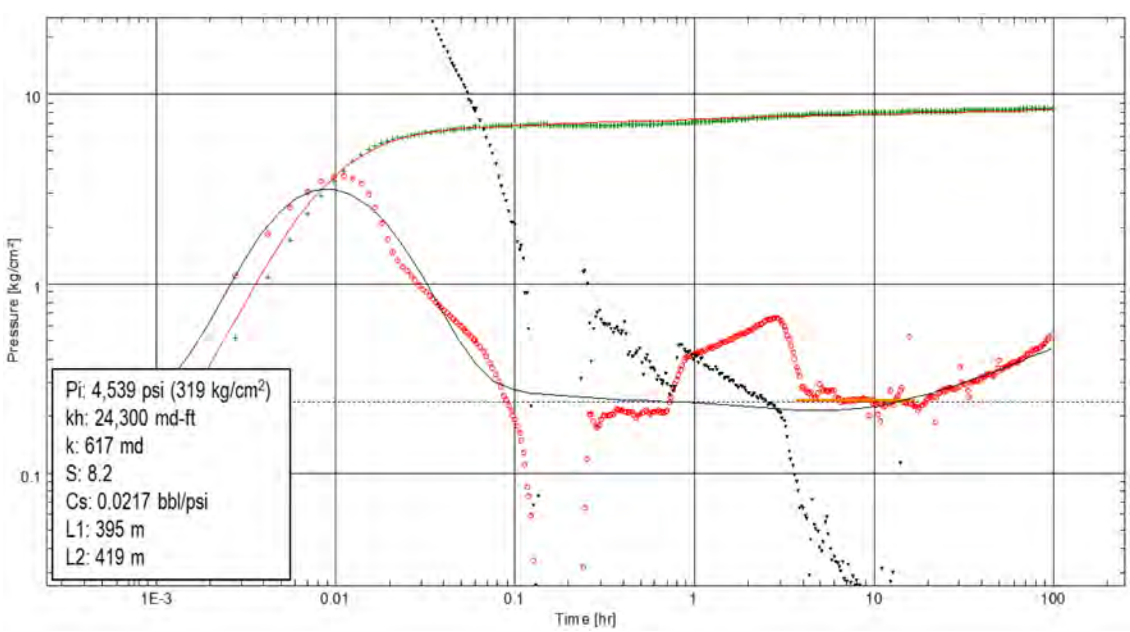

Figure 17—A 100 hours pressure build-up test of well "E".

The pressure drop was 5 kg/cm^2 (71 psi), which is significant considering the cumulative production of the well (0.1 million barrels) at that time. Additionally, another critical issue is that the bubble point pressure is too high, which means that the dissolved gas will be free after a short production time. As a result of the information obtained through the ELT, it was possible to determine that the hydrocarbon volume available in this sand body was not enough to support more producing wells, so a modification of the main objective of the following wells to be drilled was done; instead of completing them for the exploitation of the first sandstone, they were relocated to evaluate the shallower ones.

Well "F" is an offshore wildcat drilled and completed at 4,240 m in TVD in a carbonated formation of Upper Jurassic Kimmeridgian age. The effective porosity is around 10% and the initial water saturation is 18%; it is a 34.5°API volatile oil producing with a GOR of 246 m^3/m^3, the reservoir temperature is 122°C, the original reservoir pressure is 534 kg/cm^2 (7,593 psi) and the bubble point pressure is 319 kg/cm^2 (4,536 psi). An ELT was carried out with a DST during the completion of the well to better describe the reservoir behavior; it was a 178 hours pressure build-up modeled as a homogeneous reservoir with a limited entry well and a constant pressure limit; the test registered an average reservoir pressure of 534 kg/cm^2 (7,599 psi), a flow capacity of 9,590 md-ft, an oil effective permeability of 43 md, the k_z/k_r ratio was 0.0987, the skin factor was calculated to be 37.2 and the radius of investigation was 415 m (Figure 18).

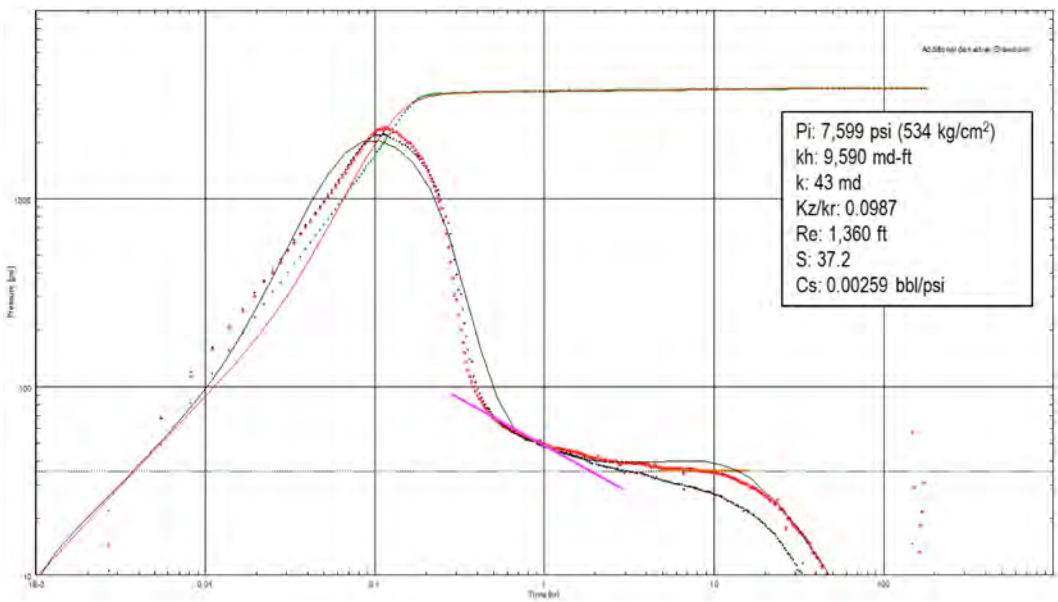

Figure 18—A 178 hours DST from well "F".

The ELT detected a constant pressure limit since the discovery of the field, because the reservoir is influenced by an associated aquifer (Figure 19). It is expected that the reservoir heterogeneity and the presence of low permeability layers interspersed within the formation could act as a natural barrier to the water flow; however, higher production rates could provoke early water breakthrough by tonguing effects (water advancement through high permeability layers in between the reservoir), reducing the recovery factor of the field.

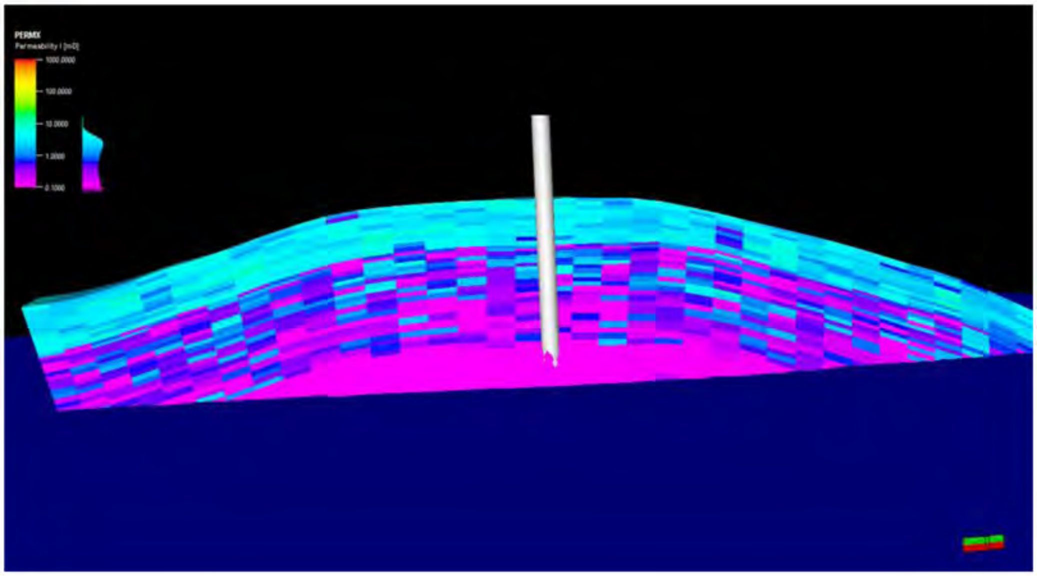

Figure 19—Structural position of well "F".

Well "G" is another offshore exploratory well that discovered a new block produced by saline intrusions, that caused severe compartmentalization at Upper Jurassic Kimmeridgian. The reservoir consists of deep carbonates at 5,700 m in TVD, whose effective porosity is 6% and the average water saturation is 13%, the reservoir produces a 37°API light oil producing with a GOR of 262 m^3/m^3, the reservoir temperature is 166°C, the original reservoir pressure is 822 kg/cm^2 (11,689 psi) and the bubble point pressure is 260 kg/cm^2 (3,697 psi).

An ELT was performed for reservoir dynamic characterization purposes through a 116 hours pressure build-up with a DST, whose response was modeled as an infinite two-layer reservoir and a changing storage well, where the average reservoir pressure is 799 kg/cm^2 (11,370 psi), the flow capacity is 4,110 md-ft, an oil effective permeability of 8.95 md, the layer storativity ratio (ω) is 0.258, the inter-layer flow parameter (λ) is 1.24E-06, the ratio of the permeability-thickness product of the first layer to the total of both (K) is 0.844, the skin factor in the high permeability layer is 12, while the skin in the low permeability layer is 82.3 and the radius of investigation was 1,074 m (Figure 20).

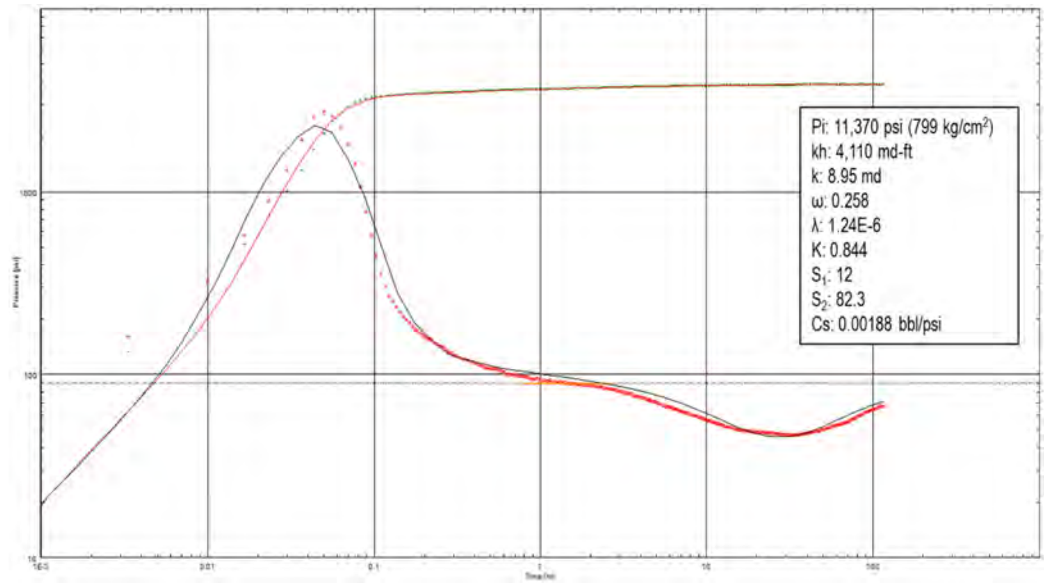

Figure 20—A 116 hours DST from well "G".

This reservoir has shown evidence of double-permeability behavior according to the PTA, PLT and the petrophysical evaluation (Figure 21); it can be seen that at early times there is no pressure difference between the layers and the system could act as two comingled homogeneous layers without crossflow; nevertheless, as the most permeable layer produces more rapidly than the less permeable one, a pressure difference increases between the layers and crossflow begins.

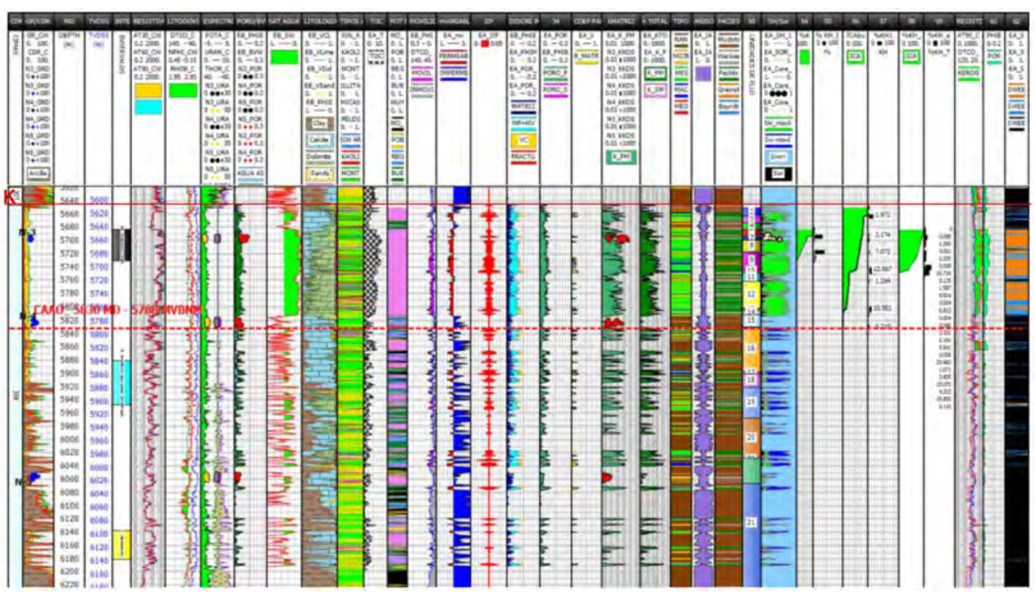

Figure 21—Petrophysical evaluation of Well "G".

After a stimulation, the well was evaluated with another ELT through a pressure drawdown acquired with a down-hole permanent pressure gauge over 8 months; due to the noisy behavior of the downhole pressure gauge, the pressure response was reprocessed through deconvolution; also, it is important to remark that because of the large duration of the drawdown and the associated transmissivity and diffusivity of the system, it was possible to detect the reservoir limits, which are quite consistent with the static model (Figure 22).

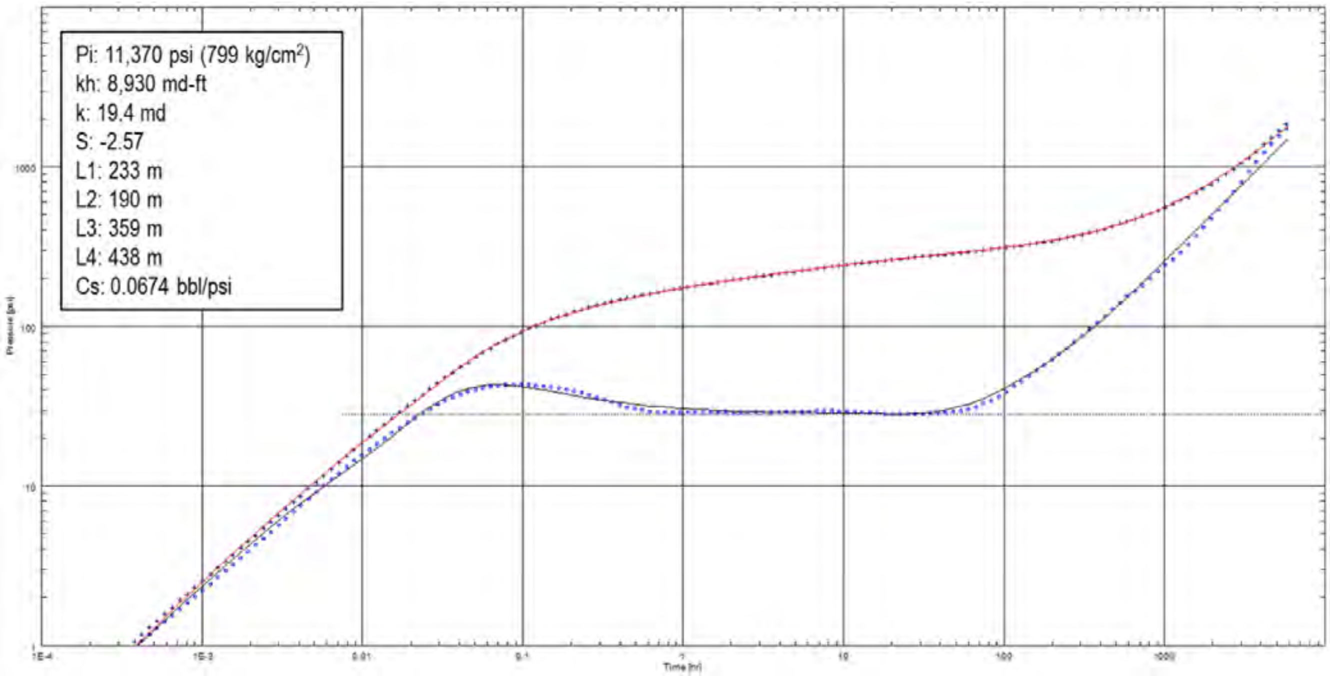

Figure 22—ELT through a large pressure drawdown (5,760 hours) deconvolved from well "G".

Finally, the last case of study is related to well "H", which was the discoverer of a reservoir in a brittle and poorly cemented formation, whose sedimentary environment corresponds to turbiditic flows that formed fans at the base of the talus, which shaped a complex of channels, levees and lobes in a Tertiary sandstone reservoir (Upper Miocene). The effective porosity is 21% and the initial water saturation is 29% (Figure 23), the hydrocarbon is a 36°API light oil producing with a GOR of 144 m^3/m^3, the reservoir temperature is 115.6°C, the original reservoir pressure is 790 kg/cm^2 (11,234 psi) and the bubble point pressure is 218 kg/cm^2 (3,100 psi).

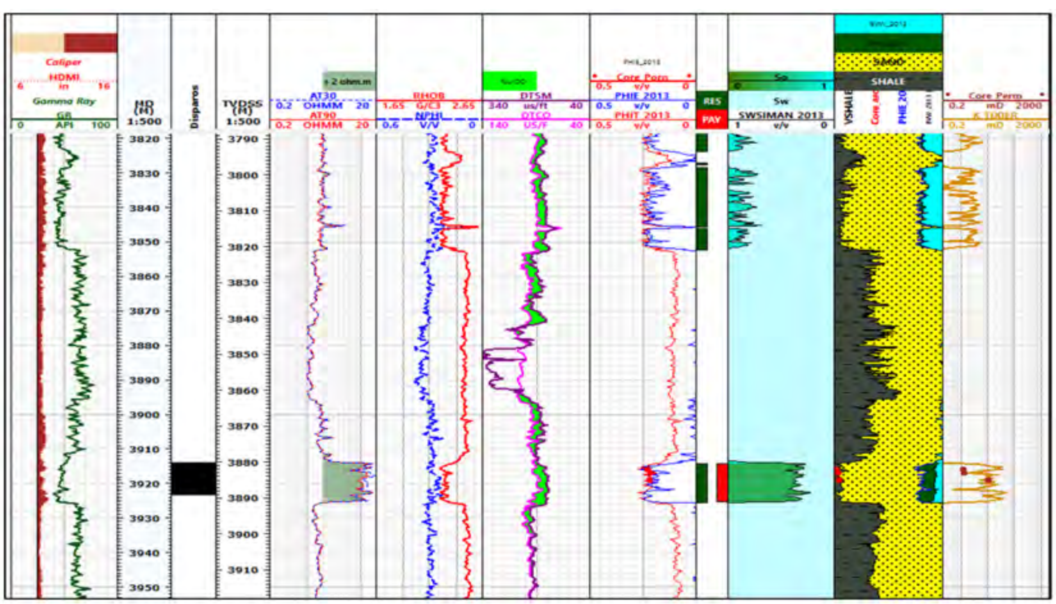

Figure 23—Petrophysical evaluation of well "H".

The well was not evaluated correctly during its completion because there were only two pressure build-ups of short shut-in time (10 hours) then, it was put to production; thus, because of the reservoir and fluid properties, such as transmissivity and diffusivity, the shut in time was not enough to investigate further within the formation and to detect reservoir limits. After 5 years of production and having two wells recently completed and producing, an interference effect was observed in the well "H" while performing a large pressure build-up (1,288 hours) due to operational constraints. The adjusted model was a radial composite system with a limited entry well and changing storage. The average reservoir pressure was 8,100 psi (570 kg/cm^2), the flow capacity was 167 md-ft, the effective permeability to oil was 5.1 md, the mobility ratio was 2.97 md/cp and the diffusivity ratio was 63.8, the skin factor was 4 and the inner radius was 4.75 m. The adjusted model is suitable for the reservoir description considering the sedimentary environment (channels); likewise, a second radial flow was identified in the pressure derivative plot at the LTR as a levee zone with poorer properties (the oil effective permeability in this zone was 2.49 md). Furthermore, at the end of the pressure derivative, in the LTR, it was observed that the pressure data showed a downward behavior, which could be tricky in case of considering a constant pressure limit, which was not the case because the aquifer is very weak, but, this phenomenon was a direct consequence of interference between wells (Figure 24).

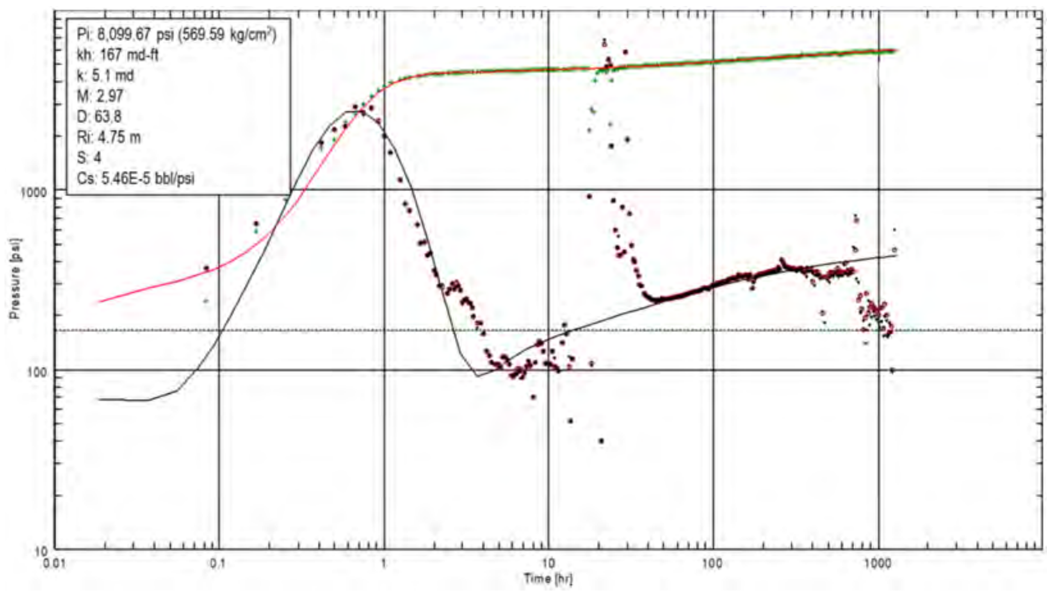

Figure 24—A 1,288 hours pressure build-up ELT from well "H".

Investigation and Drainage Radius for Carbonates

In carbonates, natural fractures play a primary role for producibility, because they act as super "highways" for fluids production; depending on the type of natural fractured reservoir, fractures can store and produce, or just produce the fluids coming out from the matrix. For natural fractures characterization, it is important to consider the acting stress regime, which is the main controlling factor for fracture occurrence because the geologic structures reflect both, the current and past stress fields.

Tectonic regimes are classified in terms of the relationship between the vertical stress (S_v), the maximum horizontal principal stress (S_{Hmax}) and the minimum horizontal principal stress (S_{hmin}). According to Anderson (1905), the relative stress magnitudes could be normal faulting (if the main stress is the vertical one), strike-slip faulting (if the main stress is the maximum horizontal principal stress) or reverse faulting (if the main stress is the same but the second stress must be the minimum horizontal principal stress). However, it is better to consider the sedimentary basin stress regime (compressive and extensive) to determine the degree of fracturing and the characterization of the fracture systems, besides having enough information such as core analyses, thin rock laminae, petrophysics, geomechanics, etc. For practical purposes, especially in cases where PTA are performed in exploratory wells where there is a lack of information, in the present paper it is proposed to correlate the basin stress regimes and the well information with the natural fracturing through fractal geometry.

The solution for PTA in carbonates try to describe the reservoir through the evaluation of pressure behavior based on fluid properties and rock characteristics; however, in general terms, most of the solutions tend to be the same for homogeneous reservoirs, which leads to question whether the drainage and investigation radii obtained in carbonated reservoirs are correct or not.

The present paper also attempts to propose a practical approximation for the well drainage and investigation radii considering the nature of fractures in carbonates. The concept of drainage radius is commonly used without proper understanding of its performance associated to the stabilization time and obviously, its limitations. In a practical way, the stabilization time could be defined as the time needed to reach the beginning of the pseudo-steady-state flow period, based on that, the stabilization time can be estimated for any reservoir shape (shape factor) for single well drainage areas. According to Earlougher (1977), for a well in the center of most symmetrical shapes, drawdown stabilization time is estimated from:

$$t_s \cong 380\frac{\emptyset\,\mu c_t A}{k} \tag{1}$$

If it is assumed that the system is radial, then:

$$t_s \cong 1,200\frac{\emptyset\,\mu c_t r_e^2}{k} \tag{2}$$

However, if the shape is not symmetrical with the well in the center or in the presence of two or more non-communicating layers, the stabilization time can be longer than indicated by Eq. 2. Many authors have defined the radius of drainage as a circular system with a pseudo-steady state pressure distribution, with this definition, as time increases, the drainage radius increases too when having an Infinite Acting Radial Flow (IARF):

$$rd = 0.029\sqrt{\frac{kt}{\emptyset\,\mu c_t}} \tag{3}$$

Bearing in mind that naturally fractures show the acting state of stress at the time of fracturing considering the tectonism, structural-related salt domes activity, regional stresses, faulting and folding, the influence of the magnitude of the stress regime in terms of fracture density, distribution, connectivity and aperture is critical. Since fractures present in a nonregular way in nature, we can expect a nonuniform dynamic response, that is why fractal geometry contributes with a solution to describe the pressure transient behavior in fracture networks.

PTA in fractured systems are characterized by several assumptions such as the random distribution of fractures, dual-porosity and/or triple-porosity response that could be tricky or misunderstood if there are not enough evidence of the existence of those systems, which add a higher complexity to the models. The general premise of fractured systems is that they have a Euclidean geometry (they are dense and space filling). However, when fractures are encountered in PTA for carbonates, commonly they are described as a single vertical or horizontal finite or infinite conductivity fracture with a typical slope of ½ and/or ¼, that dominate the flow at the Early Time Region (ETR), but the assumption of a single natural fracture producing through a well may not be accurate because that is not so common in nature, unless supported with sufficient geological data. Instead, a fracture network is expected to be acting, which is not necessarily perfectly connected nor space filling. Hence, fractals could be used as an approximation to characterize the fracture network of a variety of geometries and properties.

Fractals are geometrical objects which basic, fragmented or apparently irregular shape structure is repeated in a different scale. Fractals are scale-dependent and statistically vary with r in a power-law fashion, Acuna et al. (1995). They also describe how fracture density behaves as:

$$\rho(r) \propto r^{d} r_{mf^{-d}} \tag{4}$$

In this equation, variable d is the embedding dimension (integer 1, 2 or 3) and d_{mf} is the mass-fractal dimension or cluster dimension; another fractal parameter is the exponent θ that describes diffusion. When θ = 0, the connectivity between fractures is high and the diffusion is not hindered, which is not the case for natural fracture networks where tortuosity is very common, so an increase in θ is expected with less connectivity and higher tortuosity. Chang et al. (1990) developed a fractal relationship for fracture porosity and permeability as follows:

$$\phi(r) = \phi_0\left(\frac{r}{r_0}\right)^{d_{mf}-d} \tag{5}$$

$$k(r) = k_0\left(\frac{r}{r_0}\right)^{d_{mf}-d-\theta} \tag{6}$$

Also, the cited authors pointed out that Equations 5 and 6 do not suggest that porosity and permeability are radial dependent, not at all, in a fractal medium, all properties of any region of size r are scale-dependent following a power-law. For simplicity, the next relationship is assumed:

$$\frac{d_{mf}}{2+\theta} = \frac{2}{3} \tag{7}$$

d_{mf}<2 represent the intermediate flow between linear and radial and d_{mf}>2 represent the flow between radial and spherical. Also, Acuna et al. (1995) remark another important issue, that the early-time behavior of PTA in Naturally Fractured Reservoirs (NFR), frequently shows a dimensionality greater than two; nevertheless, pressure response tends to exhibit a different dimensionality due to the fact that reservoir thickness is small compared with the areal extension, as a result, the dimensionality decreases to values less than two (Figure 25).

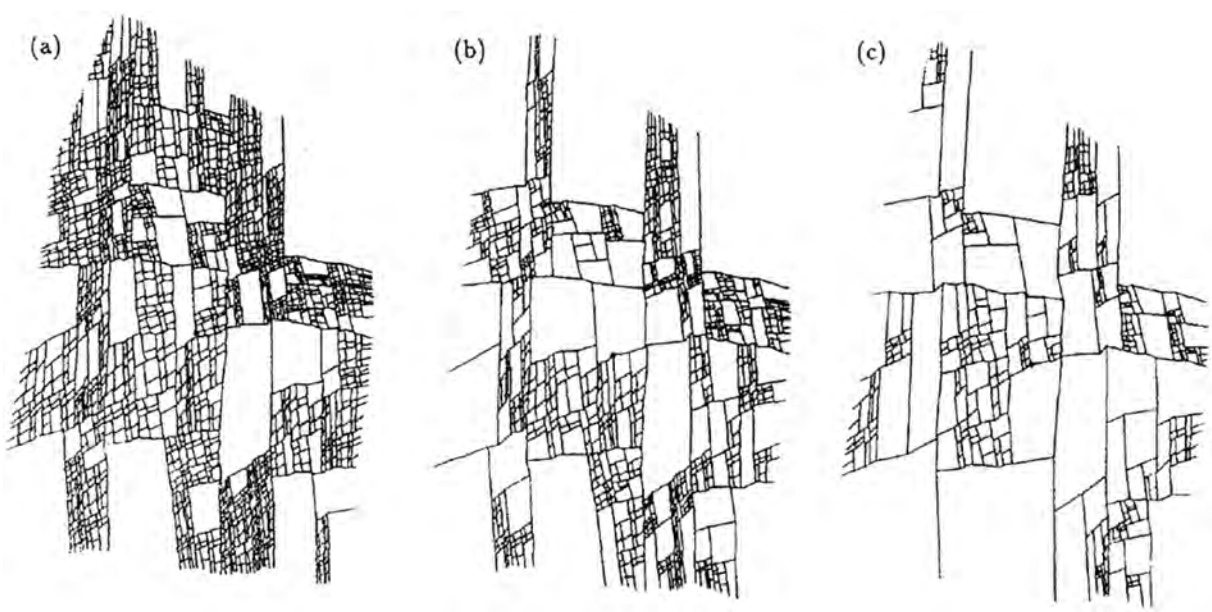

Figure 25—Examples of 2D fractal networks of fractures with different fractal dimension: (a) d_{mf} = 1.78, (b) d_{mf} = 1.65, and (c) d_{mf} = 1.47. After Acuna et al. (1995).

Due to the previous information, we assumed that the drainage areas are elliptical in relation to the orientation of the fractures instead of being circular shaped as in homogeneous systems (Figure 26). For this purpose, we suggest a simple approach in which the drainage and investigation radii could be taken as an input parameter and converted to elliptical shapes through the addition of fractal dimension based on the current stress regime, in which the circular radius obtained regularly could be resized by multiplying it by the fractal dimension and then, consider that value as the major radius a (Figure 27). Nevertheless, there exist another unknown term, the minor radius b, which should be estimated through the allocation of the structural position of the well considering also the stress regime and the geological information.

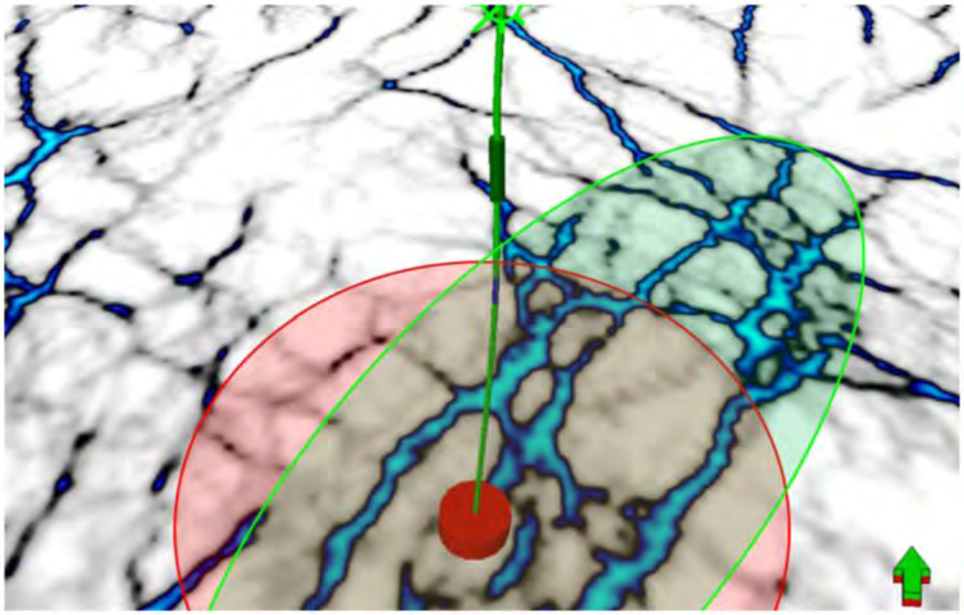

Figure 26—Ant-Tracking in an NFR showing the fracture network path that provides the hydrocarbon production to the well; an elliptical radius (green) is evidenced based on that assumption compared to a circular-shaped radius (red).

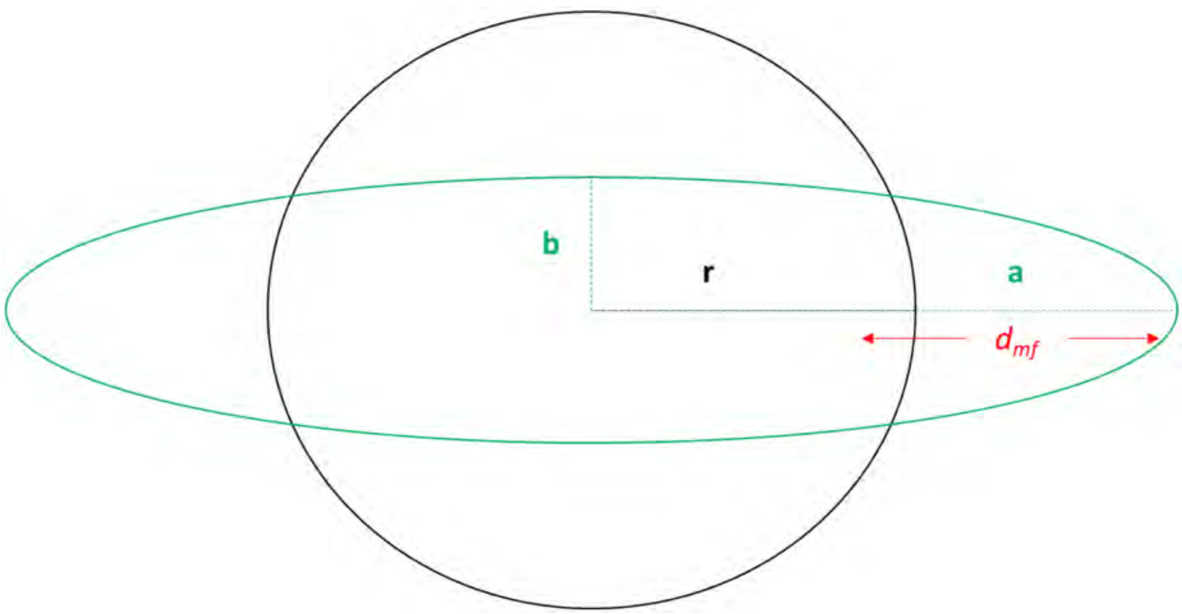

Figure 27—Comparison of circular-shaped with elliptical-shaped radius.

Despite of the fact that fractal geometry could be used for PTA in NFR, it is not possible to fully characterize this type of reservoirs because there is uncertainty in the determination of the fractal parameters; several authors reference that fractal dimension could be obtained through some techniques such as variograms, spectral methods and rescaled range (Flamenco et al. 2001). That is the reason why a complete set of information aimed to describe the nature of the fracture networks is needed, such as image logs, core analysis, thin laminae, petrophysics, geomechanics, ant-tracking and geo-statistics, which could give an approximation of the expected mass fractal dimension (Figure 28).

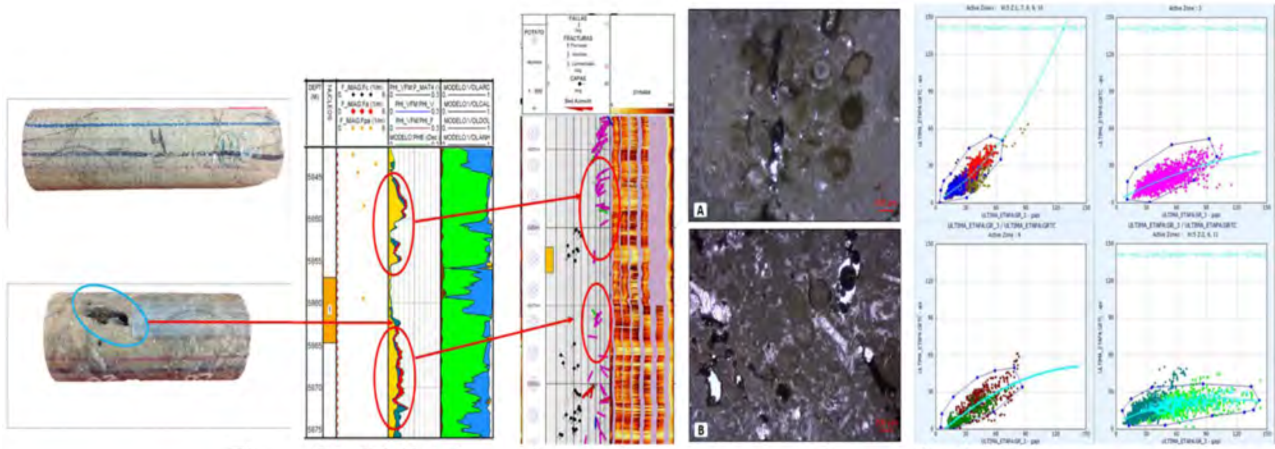

Figure 28—Well information for fracture system characterization.

After several analyses, we show the results obtained in 10 different wells producing from NFR, where their drainage radii were calculated through the conventional way (circular-shaped) and the elliptical geometry proposed (Table 1).

Table 1—Drainage and Investigation radii obtained through PTA and modified by fractal dimension.

Well	Basin Stress Regime	R_e(m) Circular-shaped	R_{inv} (m) Circular-shaped	d_{mf}	R_e (m) Elliptical-shaped	R_{inv} (m)Elliptical-shaped
1	Extensive	73	525	1.11	81	583
2	Extensive	97	377	1.16	113	437
3	Compressive	126	1,836	1.22	154	2,240
4	Compressive	175	428	1.47	257	629
5	Compressive	195	466	1.52	296	708
6	Compressive	226	854	1.65	373	1,409
7	Compressive	233	502	1.65	384	828
8	Compressive	255	627	1.78	454	1,116
9	Compressive	267	748	1.82	486	1,361
10	Compressive	307	1,141	1.91	586	2,179

Well 3 from Table 1 was evaluated to have a drainage radius of 154 m instead of 126 m, and the corresponding investigation radius was 2,240 m instead of 1,836 m estimated from an ELT, which was reasonably better considering the information acquired for reservoir description (Well "A", Pressure Transient Analysis (PTA) through Extended Limit Tests (ELT) section), see Figure 29

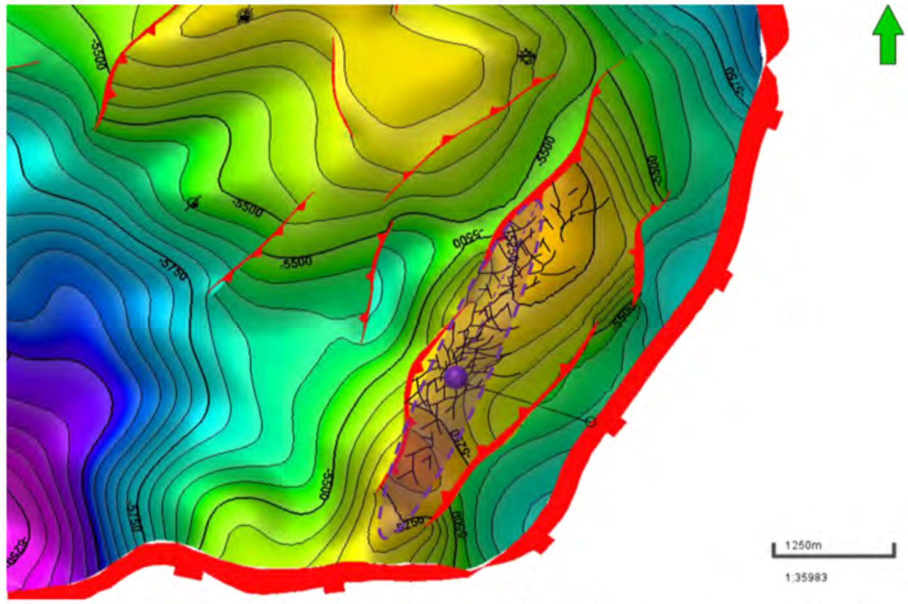

Figure 29—Structural configuration and location of well 3, showing the elliptical investigation radius.

Clearly, the investigation areas were calculated again for the same wells producing in NFR (2).

Table 2—Investigation areas recalculated for NFR.

Well	Basin Stress Regime	Area $_{inv}$ (km^2) Circular-shaped	d_{mf}	b	Area $_{inv}$ (km^2) Elliptical-shaped
1	Extensive	0.866	1.11	129	0.237
2	Extensive	0.447	1.16	85	0.116
3	Compressive	1.480	1.22	273	1.923
4	Compressive	0.575	1.47	231	0.457
5	Compressive	0.682	1.52	154	0.342
6	Compressive	2.291	1.65	233	1.029
7	Compressive	0.792	1.65	456	1.185
8	Compressive	1.235	1.78	397	1.393
9	Compressive	1.758	1.82	275	1.177
10	Compressive	4.090	1.91	416	2.850

Improved Management

Because of the highly valued information obtained through ELT for initial reservoir dynamic characterization, it was possible to establish an adequate exploitation scheme (fit for purpose) for each field according to their characteristics and behavior shown for a good reservoir management and ONW to increase the recovery factor, risk mitigation and future investments assurance based on the advantage brought by greater radii of investigation, that allows having a better knowledge of the reservoir and the behavior that would be expected.

One of the main benefits of ELT is the opportunity to have a good estimation or approximation of the Original Oil In Place (OOIP), when the radius of investigation reaches the reservoir limits. Additionally, the main reservoir drive indices could be identified since the beginning of the exploitation, which is very useful in order to design a good exploitation scheme considering the ONW, the necessary surface production facilities, and the additional requirements for secondary recovery or EOR processes.

The ELT performed in Well "B" and another appraisal well drilled in the field gave an estimated OOIP of 3,550 MMMscf of gas and 451 million barrels of oil (condensates). The ELT in the other appraisal well detected a constant-pressure limit (an associated aquifer). With all the information acquired, it was feasible to estimate the ONW for the development of this discovery, which resulted in 15 wells for primary exploitation recovery (Figure 30).

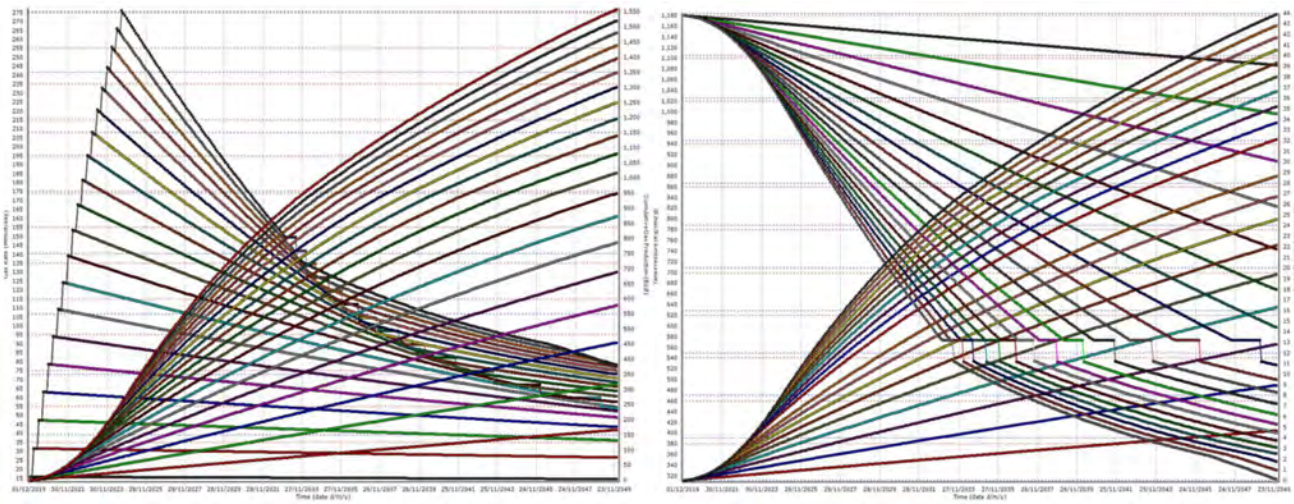

Figure 30—ONW for the field of well "B"

Well "F" also detected a constant-pressure limit associated to an active aquifer when the ELT was carried out. Furthermore, after the delimitation of the field, the appraisal wells also permitted to estimate an OOIP which resulted in 572 million barrels of oil, with that information it was possible to estimate the ONW: 10 wells for the development of the field (Figure 31).

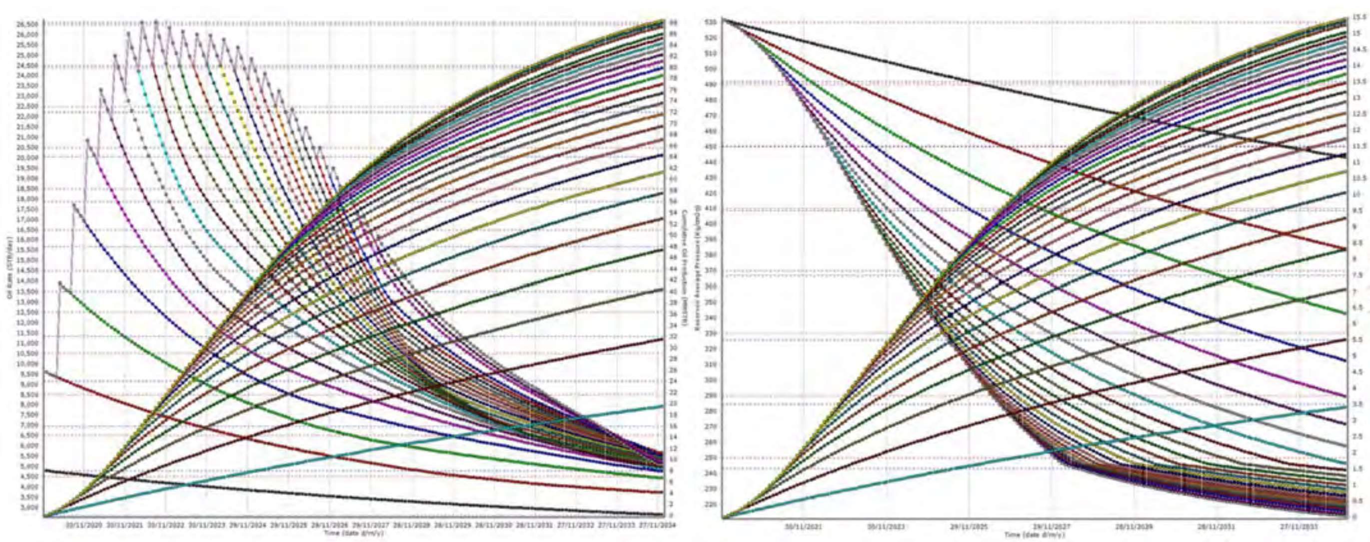

Figure 31—ONW for the field of well "F".

Well "H" has been evaluated with an ELT after the completion of three producing wells, which resulted in interference effects. Because the reservoir was developed before any thorough analysis, we had enough information to perform a full dynamic reservoir characterization, which evidenced an OOIP of 22.5 million barrels of oil. In view of that hydrocarbon volume, the ONW lead to two wells in a waterflooding scheme (Figure 32), which in turn, resulted in 47.6% increase in the expected Recovery Factor.

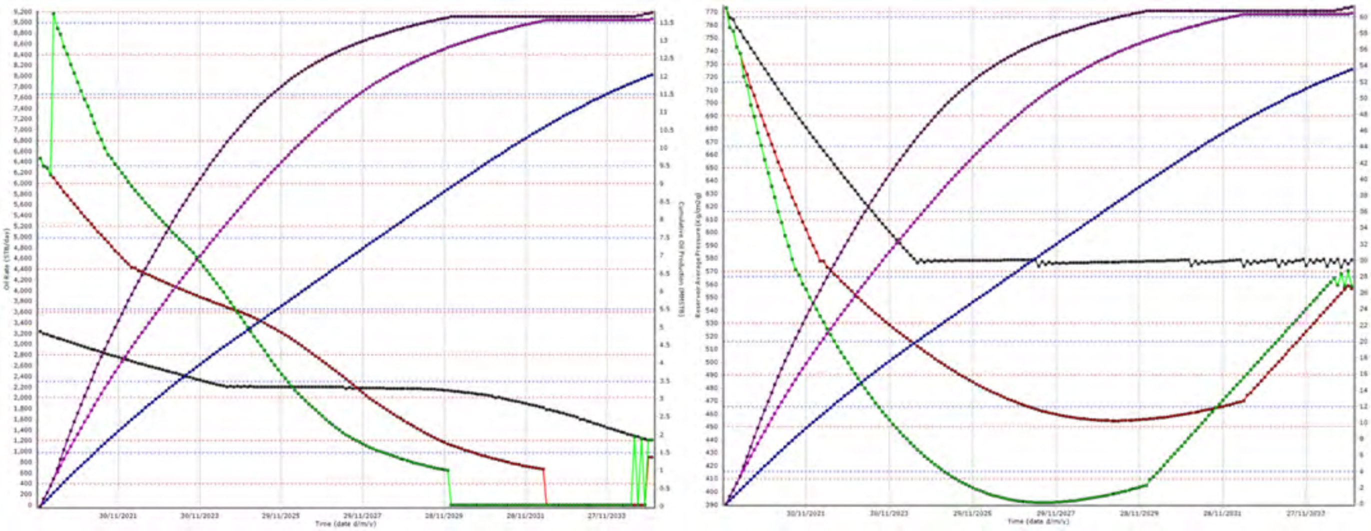

Figure 32—ONW for the field of well "H" under waterflooding.

Conclusions

The main objective of ELT is to further investigate within the formation and detect the reservoir limits for a full initial reservoir dynamic characterization, that allows an improved management through the understanding of the behavior of the producing formation since the beginning of its exploitation, as well as ensuring timely decision-making aimed to increase the recovery factor.

Unfortunately, ELT are not well valued because they require very long shut-in times (time depends on the properties of the system) until limits are detected, which usually means stopping production during the scheduled closures. However, the information obtained through ELT is essential, because it allows estimating the available hydrocarbons volume through long investigation radii, the detection of reservoir heterogeneities and limits, fluid properties and reservoir acting drive indices, and to establish the average drainage radius of the wells, which in turn, allows to design and implement an *ad-hoc* exploitation plan to approximate the ONW for reserves and investments assurance, risk mitigation and the production optimization.

Furthermore, we presented some ELT in exploratory or wildcat wells and currently producing wells in developed fields, and the responses obtained were compared, identifying the associated problems and the causes that originated them from the design, execution and finally, during the interpretation of the PTA. Additionally, we propose a practical approximation for well drainage and investigation radii considering the nature of fractures in carbonates, assuming that the drainage areas are elliptical in relation to the orientation of the fractures instead of being circular shaped as in homogeneous systems, through fractal dimension based on the current stress regime and other geological data.

One of the key issues when discover a new field is how to deal with poor or incomplete information related to geosciences mainly, for example special logs and core analyses for a good geological model, such as wettability, relative permeabilities and capillary pressures determination, formation compressibility, petrophysical evaluation and diagenetic processes. Therefore, if there is a lack of prime geological information, we cannot expect a good initial reservoir characterization, both static and dynamic.

Another critical factor is the fluid properties determination through PVT samples; meeting the proper surface, wellbore and reservoir conditions to sample from the bottom-hole or at surface when recombined is paramount for the initial reservoir characterization and consequent field development. For this purpose, we must achieve some conditions such as well production stabilization during sampling, bottom-hole and temperature monitoring before and during sampling, low (less than 5%) or absent water cut production, production testing and the prevention of reaching the reservoir saturation pressure before taking the PVT samples.

As well, it is important to mention that there are many operational factors that influence the ELT such as the type and resolution of down-hole gauges, data acquisition quality check, PVT samples, production testing, surface production facilities (if exist) and environmental risks, that must be considered for a proper ELT design and execution.

Nomenclature

API	American Petroleum Institute
Bd	Barrels per day
DST	Drill-Stem Test
EOR	Enhanced Oil Recovery
ETR	Early Time Region
EUR	Estimated Ultimate Recovery
GOR	Gas-Oil Ratio
IARF	Infinite Acting Radial Flow
MMscfd	Million Standard Cubic Feet per day
NFR	Naturally Fractured Reservoirs
LTR	Late Time Region
ONW	Optimal Number of Wells
OOIP	Original Oil In Place
PLT	Production Logging Tool
PTA	Pressure Transient Analysis
PVT	Pressure-Volume-Temperature
TVD	True Vertical Depth
A	Area (L^2)
d	Euclidean Dimension
d_{mf}	Mass Fractal Dimension
k	Permeability (md)
r	Radial Distance (L)
r_d	Radial Distance (Dimensionless)
t	Time (s)
θ	Fractal Exponent
ϕ	Porosity
μ	Viscosity (cp)
c_t	Total Compressibility (psi^{-1})
r_d	Drainage Radius (ft)
ρ	Fracture Density (L^{-2})

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