How to reduce water production while fracturing: case history from Burgos basin

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Abstract

Often, the primary challenge encountered when producing hydrocarbons in the Burgos basin is significantly associated with water production. The formations have high water saturation levels. Fracturing treatments performed in these formations usually intersect a stringer of water within the targeted interval or extended into the highly saturated areas above/below the interval.

This paper discusses how water production in a well was significantly reduced using a new associated polymer pre-fracturing (APPF). The results of this successful treatment are discussed and compared to another fracturing treatment (without APPF), showing that the untreated well produced 100% water.

The design, field application, and results of this treatment are presented.

Keywords: Water production, while fracturing, Burgos basin.

Cómo reducir la producción de agua mientras se realiza fracturamiento hidraúlico- caso histórico de la Cuenca de Burgos

Resumen

A menudo, el principal desafío encontrado al producir hidrocarburos en la Cuenca de Burgos es la producción significativa de agua asociada. Las formaciones tienen altos niveles de saturación de agua. Los tratamientos de fracturamiento hidraúlico realizados en estas formaciones generalmente cruzan una zona de agua movible dentro del intervalo objetivo o se extienden en las áreas altamente saturadas por encima / debajo del intervalo.

En este trabajo se analiza cómo la producción de agua en un pozo se redujo significativamente el uso de un nuevo polímero asociado pre - fractura (APPF) . Los resultados de este tratamiento exitoso se analizan y se comparan con otro tratamiento de fracturamiento hidraúlico (sin APPF) , que muestra que el pozo no tratado produce 100 % de agua .

El diseño, la aplicación en el campo, y los resultados de este tratamiento son presentados.

Palabras clave: Producción de agua, fracturamiento hidráulico, Cuenca de Burgos.

Introduction

The Burgos basin field is in one of Mexico's four major gas-producing basins, having the third highest non-associated gas reserves. The reservoirs are complex, sandy, and highly compartmentalized, and are composed of numerous small independent blocks characterized by low permeability. Torres et al (2006).

Because of an increasing demand for national gas production in the Burgos basin, mature areas have been redeveloped to revive and incorporate reserves in traditional producer deposits, including reservoirs with high movable water saturation in which water production is greater than 400 BWPD, such as the Monterrey or Oligocene Frio Marine formations.

To economically exploit the field, given the petrophysical characteristics (low-permeability sandstones), a fracture stimulation treatment is necessary. One type of challenging reservoir is one that does not produce normally without hydraulic-fracturing treatments and has water zones near the hydrocarbon zone. Once these reservoirs are completed using standard hydraulic fracturing processes, water production increases. Abdel Meguid et al (2010).

When fracture stimulation treatments are performed on oil- or gas-producing zones with close proximity to (1) high-permeability streaks that produce water, (2) other zones above or below the pay that have a high water content or influx, or (3) water-bearing zones, unwanted water production can result. Dalrymple et al (2008).

APPF is based on the action mechanism of a relative permeability modifier (RPM) polymer, and the main improvement is the use of a hydrophobically modified water-soluble polymer (HMWSP) in its formulation. Of all the types of current materials available for radial conformance treatments, RPMs are the only ones that do not cause damage to oil zones and can be injected under high shear (pressure and rate). Therefore, they become the obvious choice for these formations, and those RPM polymers that are chemically compatible with the selected fracturing fluid can be used in the fracturing treatments. Di Lullo et al (2002).

By adding an RPM polymer to the fracturing fluid, preferably to the pre-pad and pad stages or, in some cases, throughout the complete treatment, a resistance to water flow will be created in the fracturing fluid filtrate invaded region on either side of the fracture faces and possibly also inside the proppant pack itself. This resistance to water flow will limit the amount of water moving from the formation into the high conductivity proppant pack Thus, a conformance-fracturing technique is a method of selectively stimulating a well. Oil productivity is selectively increased, while water productivity is selectively decreased or maintained constant. Leal et al (2005).

Producing one barrel of water requires as much or more energy as producing the same volume of oil. In addition, water production causes other related problems, such as sand production, the need for separators, disposal and handling concerns, and corrosion of tubulars and surface equipment. Dalrymple et al (2008). Increased water production when using conformance-while-fracturing methods is typically less than 50% of that observed in offset wells fracture stimulated using conventional methods. Additionally, the total production of wells stimulated using conformance-while-fracturing methods usually experiences lower water-gas ratios. Dalrymple et al (2008).

Under high-shear conditions, such as flow through a pore throat (or through a micro-fracture), the HMWSP undergoes changes that cause it to function as if it were a high-molecular-weight polymer. Taylor y Nasr-El-Din (1998). It is believed that, during the fracture-stimulation portion of the treatment, the HMWSP polymer improves the fluid-loss properties of the carrier fluid, **Figure 1**. The leakoff that occurs helps reduce the effective permeability to water without increasing risks to the hydrocarbon sections. During the dynamic stage of the fracture stimulation, when the rock is exposed, the HMWSP is present. Thus, the entire created fracture receives treatment at the same time. Dalrymple et al (2008).

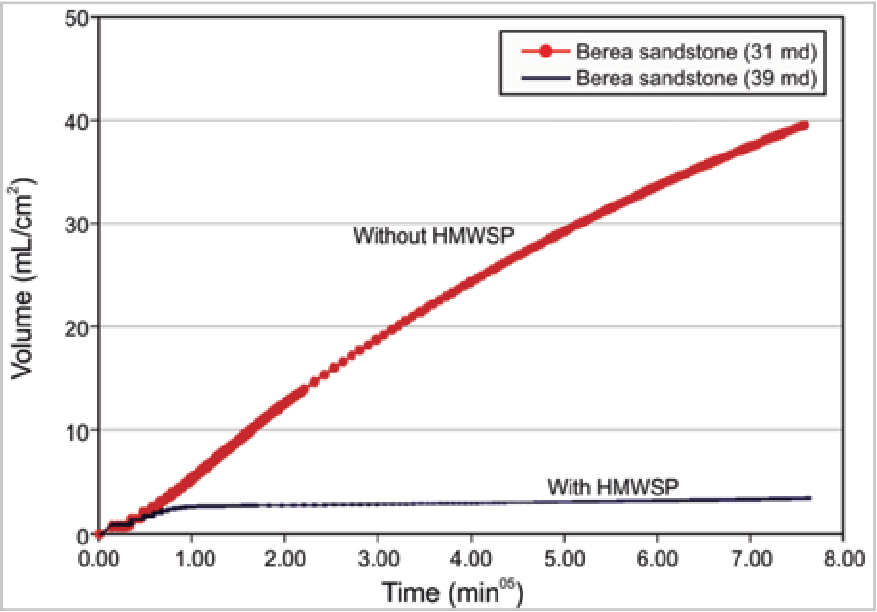

Figure 1. Fluid-loss characteristics of HMWSP at 140°F.

This paper focuses on how the water-gas ratio resulting from a hydraulic fracturing treatment in reservoirs with high movable water saturation and low permeability in the Burgos basin can be significantly reduced using APPF.

Reservoir history

Commercial production in the Burgos petroleum province began in 1945 with the discovery of Mission field in the Vicksburg play. Production increased from 1956, primarily because of the development of the Reynosa field, reaching 620 MMscf/D in 1970. During the 1970s and 1980s, production declined because investments and human resources were focused on the exploration and development of fields in the southeast oil province.

However, in the early 1990s, a change occurred in energy policy and the promotion of clean energy sources. A campaign began to use three-dimensional (3D) seismic acquisition, new geological concepts, new drilling technologies and well completions, and multidisciplinary work; as a result, the basin revitalization of the field began in 1994, reversing the decline and increasing production from 200 to greater than 1,000 MMscf/D.

Approximately 85% of Burgos production in 1999 derived from the eight largest fields, the largest contributors being Culebra and Arcos. The other six fields are Arcabuz, Cuitlahuac, Merced, Monterrey, Pandura, and Reynosa. The Gas Technology Institute believes that Burgos basin output will increase from the 1999 rate of 0.97 to 2.3 Bscf/D in 2015. In 2010, production was 1.6 Bscf/D, Talwani (2011).

The Burgos basin has 179 active fields, with 2,771 wells completed since 2004; the basin produces more than 1300 MMscf/D (Figure 2) and has accumulated more than 11 trillion cubic feet of gas, Pemex Exploración y Producción (2013.)

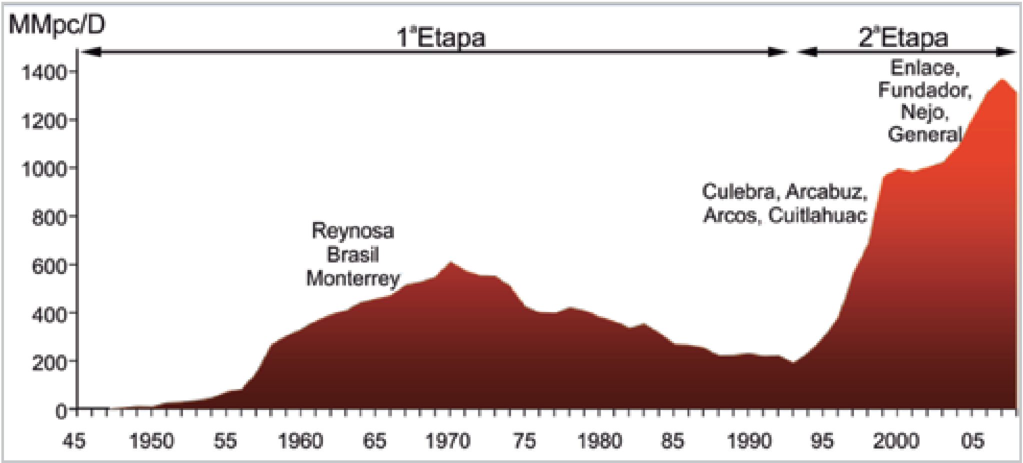

Figure 2. Historical annualized production of the Burgos petroleum province.

Geological description of Burgos Basin

The Burgos basin is a gas-bearing geologic province of Tertiary age located in northeast Mexico, just south of the Texas border in the United States of America. The Burgos basin has an approximate area of 49,800 km^2. The Tertiary basin extends to the north into the Rio Grande Embayment, to the east up to the continental margin of the Gulf of Mexico, and to the west where the basin covers the eastern portion of the Burro-Picachos Mesozoic platform.

The Burgos basin was established as a very thick sedimentary column with rocks of the Upper Jurassic, Cretaceous, and Tertiary ages, having a composite thickness of more than 5,000 m. The Mesozoic sequence is primarily composed of carbonate, terrigenous, and evaporate sections. While the Tertiary sequence is mainly clastic, alternate sand, and a shale section deposited in successive, transgressive, and regressive stages forming an overall regression to the east from the Paleocene up to the Pleistocene.

In the Burgos geologic province, gas production has been established in all of the stratigraphic columns; the Upper Jurassic and Cretaceous reservoir discoveries are isolated, scarce, and mostly have low permeability, which makes them somewhat insignificant. On the contrary, the Tertiary reservoir sands are multiple, with great variety in terms of form, and exhibit very wide distribution. The extension of the Tertiary reservoirs in the basin makes it possible to subdivide the province into five elongated and subparallel production strips **Figure 3**. These strips are designated as the Jurassic and Cretaceous, Paleocene, Eocene, Oligocene, and Miocene strips, Echánove (1986).

This paper focuses on the Oligocene strip. The formation of interest for the Monterrey field is the Oligocene Frio Marine (OFM), which was formed by the varying graduation of brackish environments mixed with marine environments, where a clay-sandy sequence was deposited with isolated intercalations of sandstone.

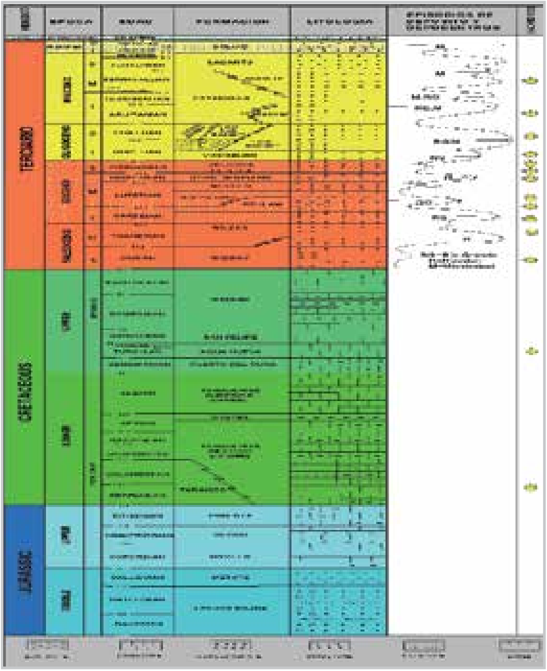

Figure 3. Stratigraphic column of the Burgos basin and its associated main tributary deposits.

RPM technology

The oil industry has used permeability modifiers since the 1970s. Abdel Meguid et al (2010). The governing mechanism for an RPM is the segregated flow of oil and water, **Figure 4**, Torres et al (2006).

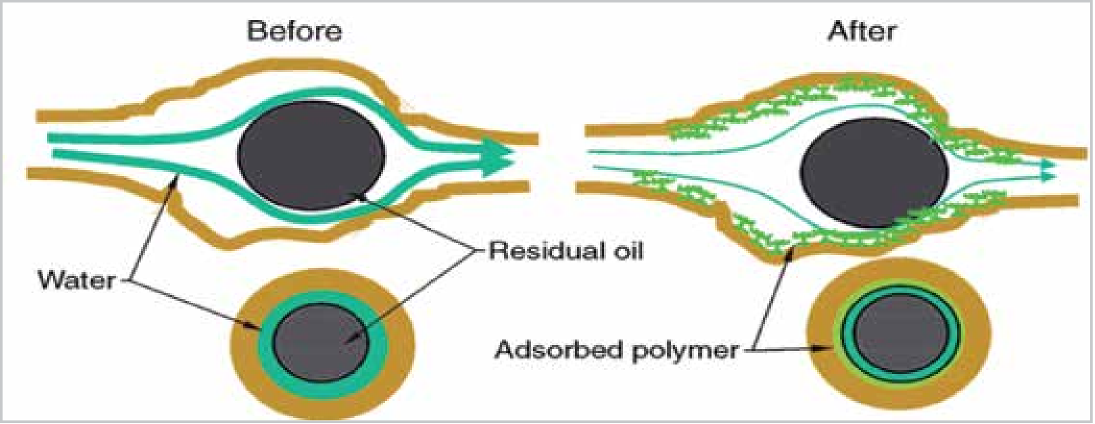

Figure 4. Proposed RPM mechanism.

The RPM system in this study consists of hydrophobically modified water-soluble polymers, resulting from hydrophobic groups introduced into the polymer chains. The RPM system adsorbs permanently onto the rock surface of the pore-throat wall. The presence of hydrophobic groups contributes to an increased level of polymer adsorption and changes rock interaction with reservoir fluids, in terms of interfacial tension and capillary pressure, without allowing flow channels to be physically plugged, Dalrymple et al (2007).

These characteristics provide the following benefits: an immediate reaction (shut-in time is not required); reduced permeability to water (more than oil and gas); unaffected by multivalent cations, oxygen, or acids; no required catalyst and non-gel forming; special placement techniques are not necessary, González Pinto y Gutiérrez (2009). The system exhibits low viscosity, typically less than 2 cp. The hydrophobic modification of the water-soluble polymer allows multiple layers of the polymer to build up because of the association of the hydrophobic groups, **Figure 5**, Vasquez et al (2010).

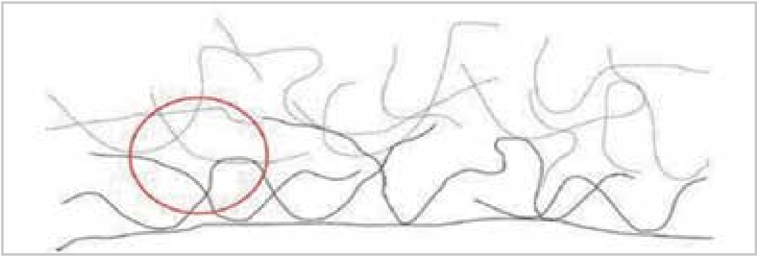

Figure 5. RPM system base polymer.

The APPF used in this treatment has notable advantages compared to other RPMs—it is a water-soluble polymer, with the addition of water-insoluble chains that act as a barrier to retain water solubility.

Design considerations

Generally, the main considerations for selecting RPM treatments to help control water-production problems should include the following conditions, Butermans, CW et al (2001), Sydansky y Seright (2006):

- Water being produced from a multi-layered formation.
- No cross-flow between layers.
- No mobile water in the hydrocarbon-productive zone.
- The reduction in oil production from the watered-out zone must be acceptable.

Additionally, the process of selecting candidates to be fractured in a conventional manner is difficult, Castaño et al (2002). The possibility of contacting zones with high water saturation exists because of the following:

- Water zones next to the fracture interval.
- Fracture communication with the oil/water contact.
- High-permeability channels affected by the water-injection process.
- Uncontrolled fracture growth.
- Layers with different properties.

There are some concerns about post-fracturing treatment durability, Castano et al (2002) point out that the treatment durability is strongly dependent on flow rate. RPM treatment efficiency is reduced as flow rates increase. High flow rates generate high shear stress in the pore channel structures, which can sweep polymer molecules that are weakly bonded to pore surfaces, Díaz et al (2009).

The treatment durability is strongly dependent on the production fluid flow rate. Fractured formations tend to create a slow linear flow pattern from the formation into the proppant pack. This effect is essential for RPM treatment success. Castaño et al (2002).

For the design of the Monterrey 4014 well, APPF was applied before the minifrac by first using a matrix flow regime, sequenced by an incremental rate until achieving a frac-extension rate to provide the most effective treatment and contact more of the created fracture, **Figure 6**.

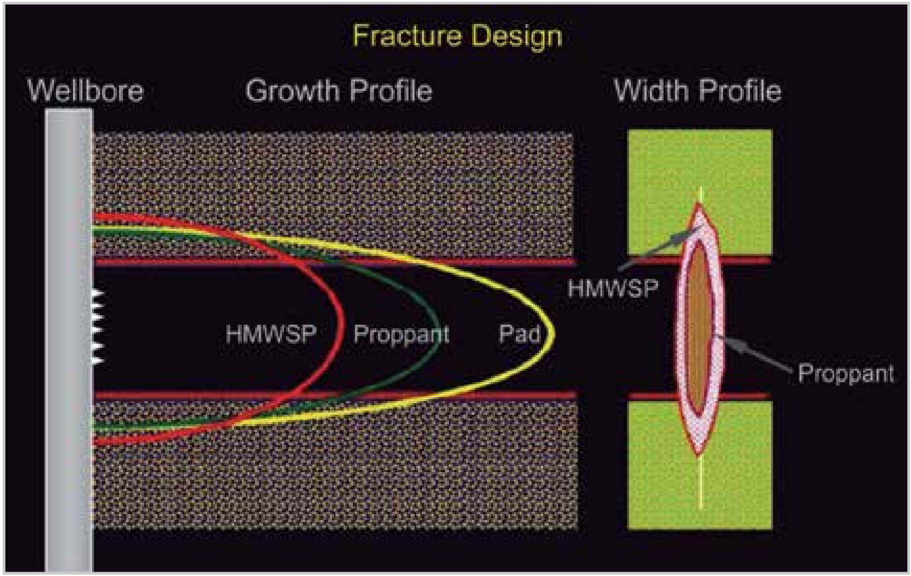

Figure 6. Schematic of conformance-while-fracturing treatment design.

APPF Case Histories

In the Burgos basin field in northern Mexico, it is typical that fracture stimulation treatments encounter water production greater than 400 BWPD, Torres et al (2006).

Monterrey 4014 Well

- Interval: 3414 to 3417 and 3422 to 3427 m, Oligocene Frio Marine (OFM)-26
- Temperature: 256°F
- Reservoir Pressure: 7,952 psi
- Permeability: 0.7 md
- Fracture Gradient: 0.91 psi/ft
- Porosity: 12%
- Water Saturation: 62%
- Tubing: 3 1/2 in., N-80, 9.2 lb/ft

In Well Monterrey 4014, APPF using a hydrophobically modified water-soluble polymer was placed in a matrix flow regime, followed by a minifrac at fracturing rates and pressure. The prepad was 5,000 gal and was flushed with 8,133 gal of linear gel. After pumping stopped and time was allowed for pressure decline analysis, the main fracture stimulation treatment was performed **Figures 7** through **10** and **Tables 1** through **3**.

High water saturation was indicated by the logs.

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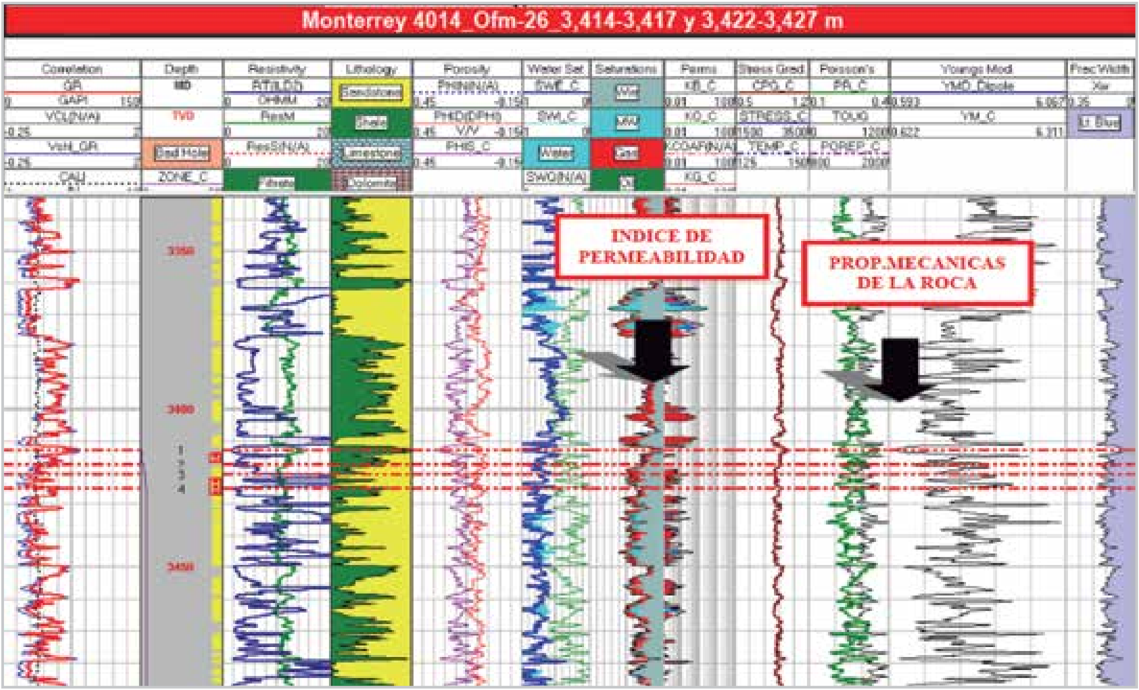

Figure 7. Monterrey 4014 log.

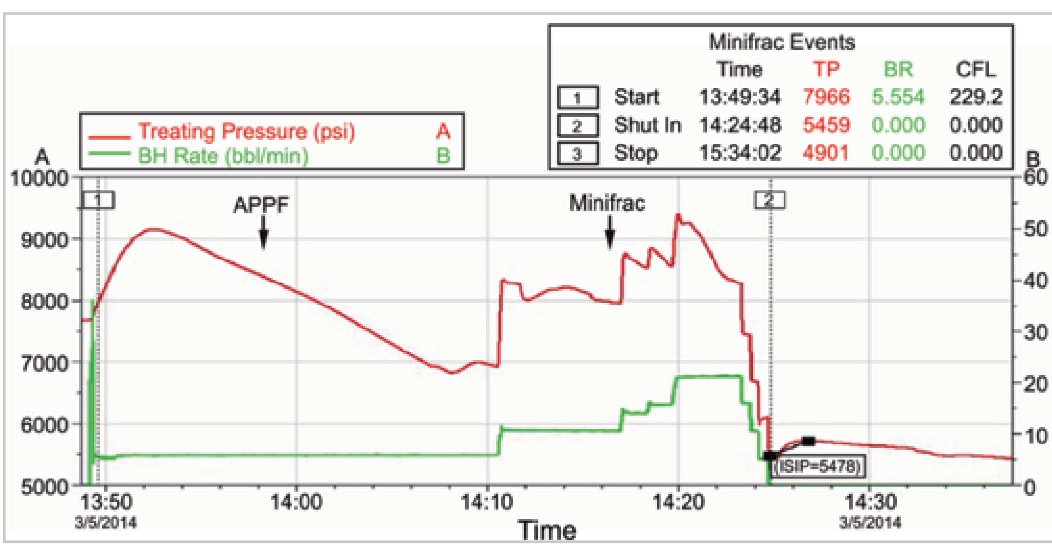

Figure 8. Minifrac of Well Monterrey 4014.

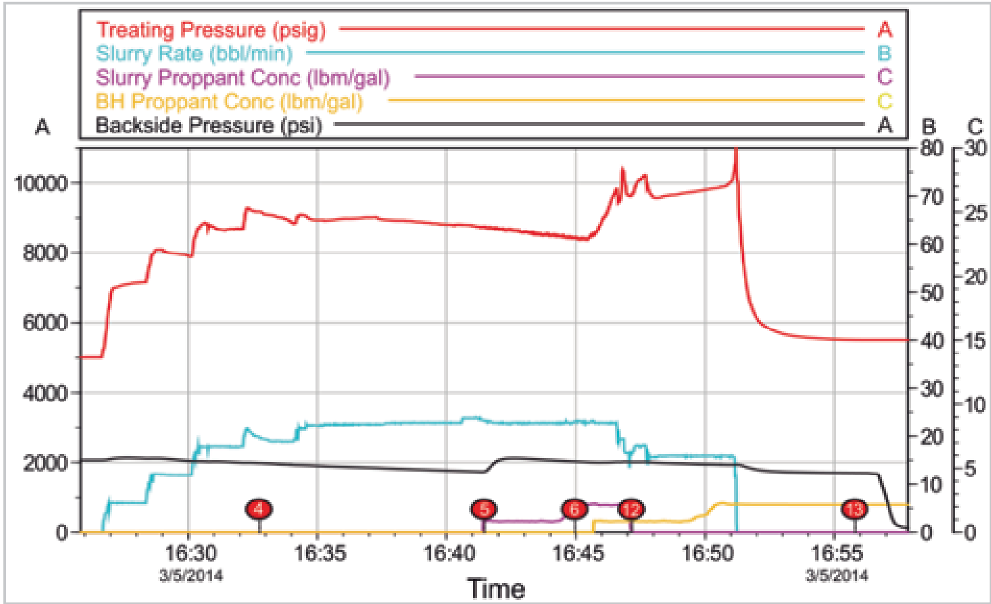

Figure 9. Fracturing of Well Monterrey 4014.

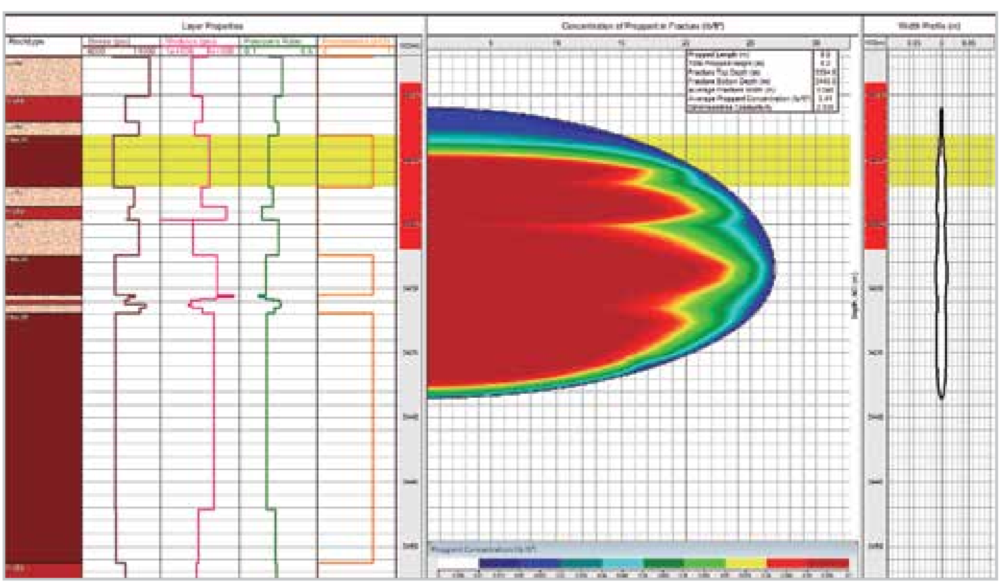

Figure 10. Fracture profile net-pressure match.

Table 1. Minifrac results in Well Monterrey 4014.

Fluid	20-lbm/1,000 gal Polysaccharide gelling agent
Volume, gal	8,133
APPF Volume, gal	5,000
Rate, bbl/min	5-20
Avg. Pressure, psi	8,300
Breakdown Pressure, psi	9,150
ISIP, psi	5,448
Frac Gradient, psi/ft	0.91
NWB, psi	900
Perf, psi	1,093
Beta Factor	0.97

Table 2. Frac results for Well Monterrey 4014.

Parameter	Design	Real
Fluid	35-lbm/1,000 gal Polysaccharide gelling agent	35-lbm/1,000 gal Polysaccharide gelling agent
Pad, gal	8,000	8,084
%PAD	22	61
Gel for Proppant, gal	28,000	5,015
Displacement, gal	4,040	2,729
Proppant Concentration, lbm/gal	1 to 7	1 to 2
Resin-Coated Proppant	1,000	140
Avg. Rate, bbl/min	35	24
Avg. Pressure, psi	9,040	8,800
Max. Pressure, psi	9,832	11,000
Final Pressure, psi	6,085	4,500
Frac Length, m	69	54
Propped-Frac Length, m	55	10
Avg. Width, in.	0.214	0.048
Height, m	69	45
Propped Height, m	55	8
Conc., lbm/ft^2	1.79	0.41
Conductivity, avg md-ft	1749	47.5
FCD	13.85	2.11

Table 3. Well Monterrey 4014 results.

Choke, in.	Tubing Pressure, psi	Gas, MMscf/D	Water, B/D	Comment
10/64	4,000	TRZ	TRZ	Prefrac
8/64	4,750	1.639	96	Post-frac
12/64	4,200	2.980	24	08/03/2014 Connect to flow station

Monterrey 4010 Well

In Well Monterrey 4010, APPF was not used. The treatment design was a conventional fracture stimulation, using 500 sacks of ceramic proppant and 500 sacks of resin-coated ceramic proppant. Results are shown in **Tables 4** through **6.**

- Interval: 2938 to 2942 and 2957 to 2961 m, Oligocene Frio Marine (OFM)-13
- Temperature: 217°F
- Reservoir Pressure: 7,064 psi
- Permeability: 0.4 md
- Fracture Gradient: 0.93 psi/ft
- Porosity: 11%
- Water Saturation: 58%
- Tubing: 3 1/2 in., N-80, 9.2 lb/ft

Table 4. Minifrac results on Well Monterrey 4010.

Fluid	Linear gel
Volume, gal	5,632
APPF Volume, gal	—
Rate, bbl/min	3 to 30
Avg. Pressure, psi	7,766
Breakdown Pressure, psi	5,617
ISIP, psi	4,854
Frac Gradient, psi/ft	0.93
NWB, psi	109
Perf, psi	422
Beta Factor	—

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Table 5. Frac results for Well Monterrey 4010.

Parameter	Real
Fluid	30-lbm/1,000 gal Polysaccharide gelling agent
Pad, gal	8,990
%PAD	22
Gel for Proppant, gal	31678
Displacement, gal	3,490
Proppant Concentration, lbm/gal	1-6
Resin-Coated Proppant	500/500 (Ceramic)
Avg. Rate, bbl/min	30
Avg. Pressure, psi	7421
Max. Pressure, psi	8,353
Final Pressure, psi	4725
Frac Length, m	—
Propped-Frac Length, m	—
Avg. Width, in.	—
Height, m	—
Propped Height, m	—
Conc., lb/ft^2	—
Conductivity, avg. md-ft	—
FCD	—

Table 6. Well Monterrey 4010 results.

Choke, in.	Tubing Pressure, psi	Gas, MMscf/D	Water, B/D	Comment
10/64	100	TRZ	72	Prefrac
8/64	2,100	0.000	288	Post-frac
8/64	1,700	0.000	312	03/03/2014 Interval was isolated with a plug at 2920 m

Conclusions

The following conclusions are a result of this work:

- Hydraulic fracturing treatments can be successfully applied in formations near high movable water saturations, to reduce the water-gas ratio by using APPF.
- This process does not require modifications to fracture design or special placement techniques.
- This process helps revive reservoirs that are normally not considered as fracturing candidates, making this intervention technique economically viable for mature fields.

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Semblanza del autor

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Ingresó a Halliburton en el año 2011, donde ha desempeñado diversos cargos entre los que destacan Associate Technical Profesional y Technical Profesional Frac/Acid en el área de Production Enhacement .

Actualmente labora como Ingeniero de diseño en estimulaciones , fracturas acidas y no ácidas, fracturas hidráulicas, control de arena y conformance para la región de Latinoamérica realizando proyectos para el área de Production Enhacement en Ecuador, Bolivia y México.Entre los proyectos realizados destacan:

- MultiStage Fracturing (Rapid Frac ,Rapid Stage,Access Frac Zipper Frac , Plug and Perf)
- Shale-Frac
- Hydraulic Fracturing
- Acid Fracturing
- Hybrid Fracturing (Acid and Proppant)
- Matriz Acidizing Stimulation
- Water Control (Conformance ,RPM , Gel Sellants , Squeeze Cementing, CWF)
- Sand Control
- Well Control.
- Pinpoint Stimulation (Surgifrac , Cobra-Max)
- Hydrajet