Aplicación de buenas prácticas para mejorar la recuperación de hidrocarburos del yacimiento en trabajos de fractura multi-etapa-caso histórico en formaciones areniscas apretadas

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Información del artículo: recibido: octubre de 2015-aceptado: noviembre de 2015

Resumen

Localizada al Noreste de México, la Cuenca de Burgos es considerada como el mayor productor de gas y condensado en la región. Está definido como un reservorio de gas apretado por su composición de bloques complejos de areniscas y baja permeabilidad y porosidad promedio. Es por esto que ha sido masivamente perforada y fracturada hidráulicamente la zona para mantener niveles de producciones rentables. Recientemente, debido a la creciente demanda de hidrocarburos, las reparaciones menores y mayores en formaciones previamente probadas y otras por probar ha incrementado significativamente en pozos perforados y por perforar.

El pozo de estudio en el presente documento se encuentra localizado en el Campo Cuitláhuac en el área central de la cuenca. Esta area ha sido extensivamente estudiada y probada. Tiene una compleja estructura geológica compuesta de areniscas con una permeabilidad promedio por debajo de 0.20 milidarcies (mD) y 18% de porosidad. Esta zona produce principalmente en la edad del Oligoceno Vicksburg.

Aplicando el apropiado diseño de fractura basado en un análisis concienzudo del yacimiento para mejorar la conductividad y ayudar a asegurar la longevidad del pozo, es el objetivo primordial en la cuenca. Con base en las observaciones, el diseño de tratamiento recomendado y aplicado involucraba tres principales etapas debido a que se encontraban expuestos tres intervalos simultáneamente. En el tratamiento se utilizó un sistema de resinado al vuelo líquido del 3% en el 45 al 60% de la cola del volumen de apuntalante bombeado en cada etapa como un mejorador de la conductividad. Adicionalmente, un surfactante micro emulsionado fue utilizado para mitigar los mecanismos de daño y reducir el daño en la cara de la fractura durante la intervención del intervalo más profundo. Finalmente, se implementó un divergente mecánico biodegradable para ayudar a asegurar la estimulación de las tres zonas individualmente.

Este estudio evalúa esta técnica aplicada comparada contra tratamientos de fractura convencionales realizados en el área, observándose resultados muy superiores en el comportamiento de la producción mientras los tiempos operacionales fueron reducidos considerablemente. Esto ayudó a reducir los costos de terminación del pozo, además de crear nuevas oportunidades para maximizar la recuperación de los yacimientos, incrementando significativamente la producción de gas y condensado.

Palabras clave: Arenisca apretada, multi-fractura, resinas líquidas, surfactante microemulsionado agente divergente.

Good practices application to improve reservoir hydrocarbons recovery on multi stage frac–tight gas sandstone formation well case history

Abstract

Located northeast of Mexico, the Burgos Basin is considered the major gas and condensate producer in the area. It is defined as a tight-gas reservoir because of its complex sandstone formation blocks and average low permeability and porosity. Because of this, it has been massively drilled and hydraulically fractured to maintain profitable production levels. Recently, because of the increasing hydrocarbon demand, workover on developed and undeveloped formation layers has increased significantly in both drilled and new wells.

The discussed well is located in the Cuitláhuac Field in the central area of the basin. This area has been extensively studied and tested. It has a complex geological structure composed of sandstone with an average permeability below 0.20 milidarcies (md) and 18% porosity. It produces primarily from the Oligocene Vicksburg trend.

Applying the appropriate fracture design based on a conscientious deposit analysis to enhance conductivity and help ensure production longevity is the primary goal at the basin. Based on the findings, the recommended and applied treatment design involved three main stages as three intervals were simultaneously opened. Treatment used a 3% liquid resin coating system between 45 and 60% of the tail end of the total proppant scheduled for each stage as a conductivity enhancer. Additionally, a novel microemulsion surfactant was used to mitigate damage mechanisms and reduce fracture face damage during the deepest interval intervention. Finally, a mechanical biodegradable diverter agent was implemented to help ensure the three zones were stimulated individually.

This study reviews this technique as compared to conventional fracture treatments in the area, as results demonstrated outstanding production performance while operational times were reduced. This helped reduce completion costs, thus creating new opportunities to maximize reservoirs, significantly increasing gas and condensate production.

Keywords: Tight-gas sandstone, multi-fracture, liquid resins, microemulsion surfactant, diverting agents.

Introduction

Liquid Resin Systems (LRSs) on Proppants

It has been demonstrated by lab testing and field trials that benefit is gained through the use of surface modification agents (SMAs) and LRSs to coat proppants. Weaver et al. (2005) suggested that these techniques could reduce the potential damage associated with formation material entering the proppant pack. Another study by Blauch et al. (1999) showed that applying SMAs and LRSs to proppant resulted in proppant beds of higher porosity and pack permeability over a wide range of stresses. Another benefit from using these materials on proppant is that they minimize the loss of conductivity associated with formation mechanical properties by stabilizing the formation surface at the interface. Furthermore, LRSs have effectively been used in the industry as a proppant-flowback control agent and have proven to provide excellent results both controlling proppant flowback and increasing cycle-pressure tolerance.

The hardened LRS increases the unconfined consolidation strength (UCS) of the proppant pack (as reported in the laboratory test analysis by Nguyen et al. 1998). This additional strength allows the fracture to tolerate higher fluid velocities (production rates) without losing the proppant.

Microemulsion (ME) surfactants

One of the continuing challenges in gas wells is post-fracturing fluid recovery because of low-pressure, low permeability reservoirs. Most wells of this type are stimulated with water-based fracturing fluids and produce back less than half of the injected fluids. It is assumed that these large quantities of fluid are trapped in the reservoir surrounding the wellbore and, in the case of hydraulic fracturing, the fluid is trapped in the area surrounding the fracture and within the fracture itself. This trapped fluid can have a detrimental effect on the relative permeability, effective flow area, and effective fracture lengths and can impair well productivity.

A micro emulsion (ME) is a thermodynamically stable combination of surfactant, solvent/cosolvent, and water, which appears as a single phase that is optically isotropic. It reduces surface tension and contact angle to minimize capillary end effects. It enhances the displacement of injected fluid from reservoir in a piston-like manner to leave a lower water saturation (Sw) and a higher relative permeability; it also creates a lower effective damage ratio surrounding the fracture and within the fracture, allowing a lower pressure to move fluid in the proppant pack. This creates a longer effective fracture length (Lopez-Bonetti et al. 2012).

Biodegradable mechanical diverting agent

To refracture a well, timely isolation of certain existing perforations can be critical. The isolation is used to restrict or deny certain perforations from receiving the subsequent fracturing treatment. The isolation approach can range from using a rig to set physical barriers that redirect the fluid flow to use of specialized particulates placed in the flow stream to divert the treatment. Diverters can eliminate the need for a rig to provide physical barriers, thus improving economics of the workover operation.

Biodegradable diverters should be robust enough to survive the placement process and effectively seal perforations, to redirect flow into untreated zones by withstanding the pressures necessary to complete later stages pumped into new areas of the well, and not require a secondary treatment for them to be removed [i.e., effective but temporary and self-removing (Allison et al. 2011)].

Methodology

Well C-895 was drilled through formation Oligocene-Vicksburg 60 (OV-60) and completed tubingless with cemented 3 1/2-in. 9.3 lbm/ft N-80 grade pipe to 3280-m measured depth (MD) (3110-m true vertical depth (TVD).

For initial reservoir considerations, correlated log data was used from Wells C-869, C-843, and C-889, **Figure 1**.

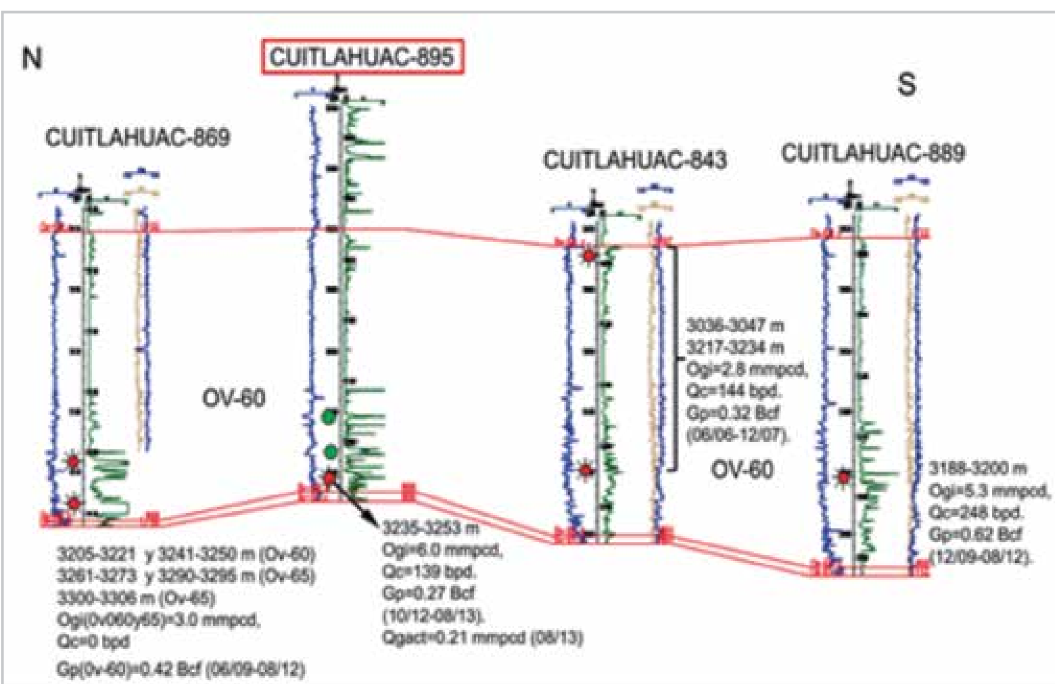

Figure 1. OV-60 stratigraphic section.

The OV-60 trend has an average permeability of 0.126 md, which is considered a tight-gas formation and requires intensive hydraulic fracturing to maintain profitable production levels. Because of this, a multistage fracturing treatment design was proposed to obtain a long-term stable hydrocarbon recovery according to the reservoir characteristics, **Table 1**, **Figure 2**.

Table 1. Reservoir properties.

Reservoir pressure (psi)	8,340
Permeability (md)	0.126
Porosity % (average)	15
Water saturation % (average)	43
Drainage area (acres)	80
Young's modulus (E6 psi)	4.92
Bottomhole temperature [BHT] (°F)	270
Frac gradient (psi/ft)	~0.9
Viscosity (cp)/API gravity	0.05/50°
Gas-specific gravity	0.63

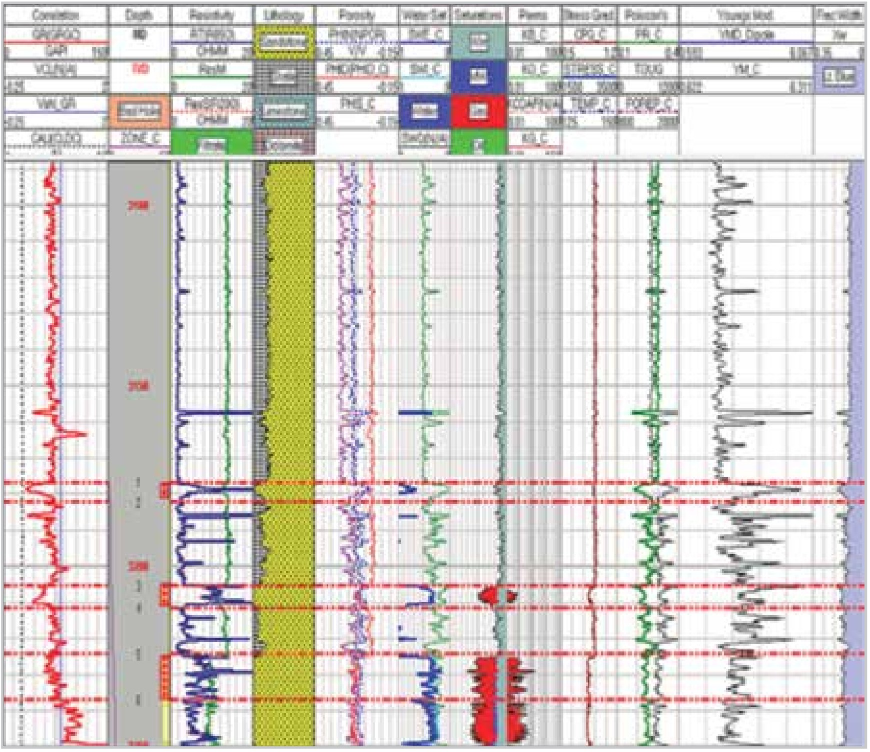

Figure 2. OV-60 formation log.

Three main stages were defined for the Well C-895 treatment according to the reservoir petrophysical properties: A (3235 to 3253 m), B (3205 to 3211 m), and C (3177 to 3181m). Interval A had been perforated previously and was placed onto production without being treated but the production curve declined drastically and quickly. A 20/40-mesh intermediate strength proppant (ISP) was selected to be used based on the high estimated closure stresses. The proppant volumes per stage were (A) 2,500 sacks, (B) 2,000 sacks, and (C) 1,500 sacks. Proppant distribution among the stages was designed to achieve an effective proppant packing with an average fracture conductivity of 2,050 md-ft and thus develop an improved flow capacity in the reservoir.

Operational summary

A minifrac injection test was performed, pumping a volume of 9,606 gal. of linear gel (10 lbm/1,000 gal; D = 1.02 gr/cm^3) with the following parameters:

- Po = 3,260 psi
- Padm = 6,081 psi
- Pinj = 7,117 psi
- Pmax = 7,869 psi
- Fracture gradient (FG) = 0.67 psi/ft
- Pump rates [Q] = 7.0 to 35.0 bbl/min
- Hydraulic horsepower $(HHP)_{max}$ = 6,750
- Instantaneous shut-in pressure (ISIP) = 2,467 psi

Rate step-down test analysis results showed a total fluid entry friction of 2,170 psi, of which 229 psi corresponded to perforation friction and 1,498 psi to near wellbore (NWB) tortuosity friction, with no bounce on rate steps. During the fluid efficiency testing analysis, based on the "G" function, square root, and log-log plots, a height recession leakoff mechanism was observed. After the analysis, it was decided to pump 290 biodegradable diverter balls between Stages A and B and 100 biodegradable diverter balls between Stages B and C to help ensure all intervals were treated. Fracture treatment data can be observed in **Table 2a** and **2b** and **Figure 3**.

Table 2a. Fracture treatment data.

Interval	Interval (m)	Proppant Vol. (sacks)	On-the-Fly Coated Proppant (sacks)	ME-Surfactant (gal)
A	3235 to 3253	2500	1250	396
B	3205 to 3211	2000	1000	N/A
C	3177 to 3181	1500	750	N/A

Table 2b. Fracture treatment data.

Interval	Rate (bbl/min)	Average pressure (psi)	Maximum pressure (psi)
A	35	6700	7296
B	35	7050	7842
C	35	7150	7891

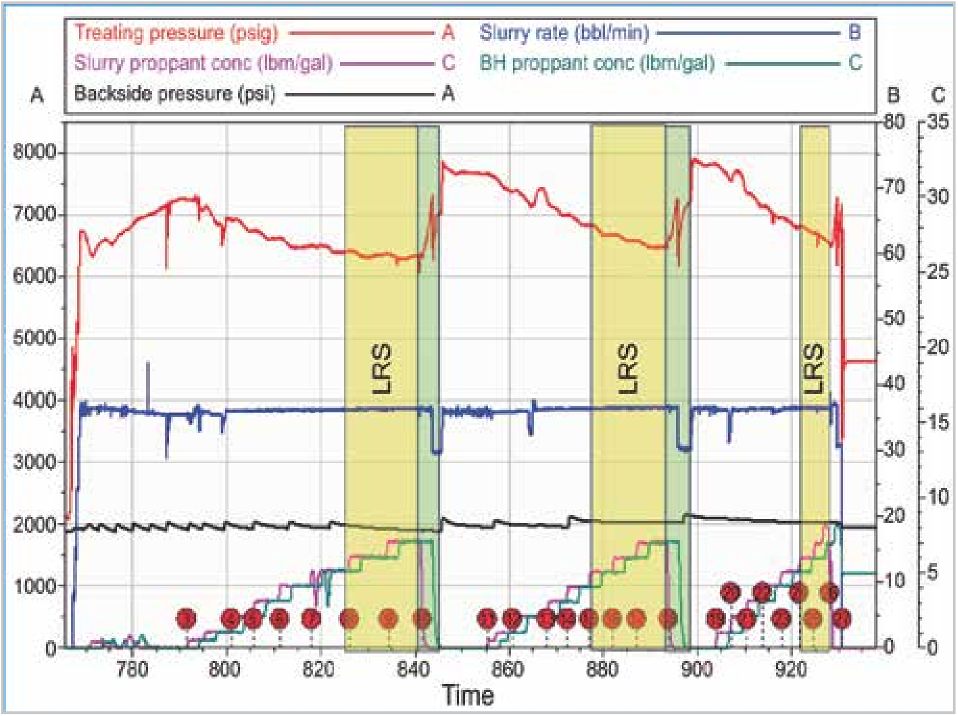

Figure 3. Fracturing treatment graph for all three stages.

Results

At the end of the treatment, 6,008 sacks of 20/40-mesh ceramic proppant had been placed into the formation; 3,000 sacks were treated with 3% liquid resin on-the-fly (coating the final half of proppant during each stage) and 396 gals of ME surfactant were pumped down hole in the first stage. The average pumping rate was 35 bpm. In **Table 3a-3b** and **Figure 4**, the estimated values of developed fracture geometries at the end of the three treatment stages can be observed.

Table 3a. Values of developed fracture geometry at the end of the job.

Fracture geometry	Interval 1	Interval 2
SLF volume (gal)	42,362	20,351
Rate (bbl/min)	35	35
Frac propped length (m)	144	120
Frac height (m)	84	71
Width average (in.)	0.12	0.13
Conc. areal average	1.17	1.27
Dimensionless fracture conductivity (FCD)	18	23
Conductivity average (md-ft)	1,345	1,373

Table 3b. Values of developed fracture geometry at the end of the job.

Fracture geometry	Interval 3
SLF volume (gal)	17,770
Rate (bbl/min)	35
Frac propped length (m)	84
Frac height (m)	45
Width average (in.)	0.17
Conc. areal average	1.71
Dimensionless fracture conductivity (FCD)	34
Conductivity average (md-ft)	1,446

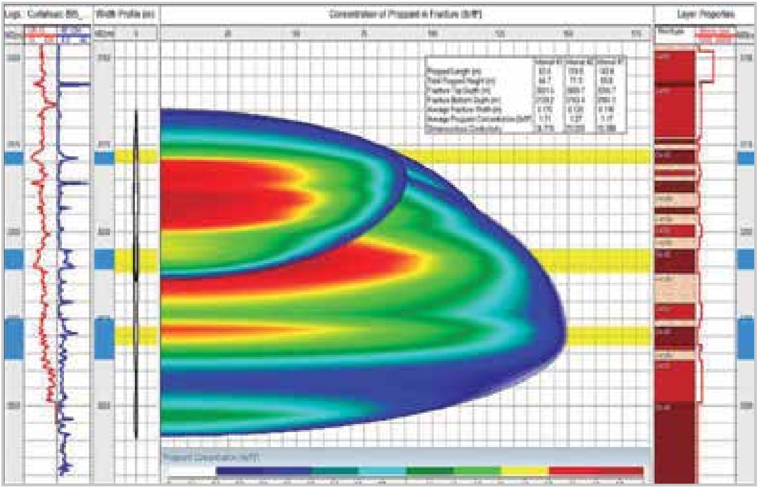

Figure 4. Treatment stages with overlapping fracture geometries at the end of the job.

The well was put onto production using chokes ranging from 8/64 to a maximum of 14/64 in. The initial surface pressure was 5,100 psi.

The well showed the presence of gas (1.736 MMscf/D) 14 hours after initial cleaning, with 2.22% recovered fluid. Condensate production began after 24 hours of flowing at the following parameters:

- Wellhead pressure (WHP) = 4,600 psi
- Qgas = 4.825 MMscf/D
- Qw = 60 BWPD
- Qc = 93 BOPD
- Reclaimed accumulated water = 2.62%

It is important to highlight that the production parameter showed very stable characteristics of WHP, maintaining an average Qgas of 4.8 MMscf/D.

Conclusions

The following conclusions are result of this work:

- Successful application of the technique discussed early in the paper, provided outstanding results that present it as a feasible option for developing wells in this type of formation with low permeability in an economically efficient manner.
- The effective job time was reduced to four hours, treating three intervals separately using a biodegradable diverter, reducing operational time and reducing costs with no need for secondary treatments.
- A stabilized post-treatment hydrocarbon flow can be observed, showing that an effective and enhanced fracture conductivity had been achieved.
- The development of this technique in this type of formation can highly increase the reservoir hydrocarbon recovery in both developed and undeveloped areas.

Recommendations

The following recommendations are a result of this work:

- It is recommended that further testing be performed in other fields and reservoirs that are considered candidates for this type of system.
- Increasing the percentage of the tail-in proppant that is coated with the liquid resin in fracture stimulation treatments (compared to earlier treatments) increased production performance, based on the results achieved in the wells studied. It should be considered for use in all of the proppant-laden stages.

Acknowledgments

The authors thank Pemex and all of the personnel involved during the execution of this operation and Halliburton for permission to publish this paper.

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