Application of hybrid fracturing treatment in sandstone formations with high content of carbonate and mixed layers using acid and proppant

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Abstract

A formation in northern Mexico includes a lithological transition between sandstones and carbonate referred to as Brecha A. Because of the high content of carbonate and mixed layer, Brecha A has a low average porosity of approximately 10%; the permeability ranges from 0.1 to 5 mD. This paper provides details about the generation, application, and production results of a stimulation treatment design that works well for this type of formation. The design selected uses a fracture stimulation with 15% hydrochloric acid (HCl) systems, immediately followed by pumping a hydraulically propped fracture treatment to generate an effective proppant pack in the fracture to further enhance productivity.

During the initial stimulation attempts, only proppant was pumped, which caused premature screenouts during operations that resulted in poor conductivity of the proppant pack and low production. After considering the carbonate content of the formation and solubility with HCl, a hybrid operation was designed to avoid screenouts and to increase the proppant concentration achieved with the fracturing operation.

The challenges of this type of operation include combining the use of an acid system followed by the crosslinked gel to pump sand into the formation with no fluid transport issues, and increasing the well productivity through the conductivity channels created. The application of this type of operation helped to reduce surface pressure. After the acid contacted the carbonate rock, the rock was dissolved in the acid. The dissolution was followed by a proppant slurry to maintain the open fracture and to maximize conductivity.

Previous proppant laden treatments using conventional techniques were not pumped to completion, and the potential to economically produce the zone was questioned because of low productivity. After changing the design, a total of 15 fracture treatments have been performed using this methodology; early screenout was reduced by 60%, and well productivity was increased by 80%.

Keywords: Fracturing, hybrid, carbonate, mix layers, acid/proppant.

Aplicación de fracturamiento hidráulico híbrido en formaciones de arena con alto contenido de carbonato y capas mixtas utilizando ácido y apuntalante

Resumen

Una formación ubicada en el norte de México incluye una transición litológica entre areniscas y carbonato denominada Brecha A. Debido al alto contenido de carbonato y a capa mixta, la Brecha A tiene una baja porosidad media de aproximadamente el 10 %; con rango de permeabilidad que oscila entre 0.1 y 5 mD. Este articulo proporciona detalles sobre el desarrollo, aplicación y resultados de producción de un diseño de tratamiento de estimulación que funciona bien para este tipo de formación. El diseño seleccionado corresponde a un fracturamiento hidráulico que incluye sistemas de ácido clorhídrico (HCl) al 15%, seguido inmediatamente por el bombeo de un tratamiento con apuntalante, para generar un paquete efectivo apuntalado y así mejorar aún más la productividad.

Durante los primeros intentos de estimulación, sólo se bombeaba apuntalante, lo que provocó arenamiento prematuro durante las operaciones, lo que dio lugar a una mala conductividad de la fractura apuntalada y una baja producción. Tras considerar el contenido de carbonatos de la formación y la solubilidad con HCl, se diseñó una operación híbrida para evitar arenamiento y aumentar la concentración de apuntalante durante la operación de fracturamiento.

Los retos de este tipo de operación incluyen la combinación del uso de un sistema ácido seguido del gel reticulado para bombear arena hacia la formación sin problemas de transporte de fluidos, y el aumento de la productividad del pozo a través de los canales de conductividad creados. La aplicación de este tipo de operación ayudó a reducir la presión de superficie, debido a la acción del ácido al entrar en contacto con la roca carbonatada. A la disolución de la roca, le siguió una lechada de apuntalante para mantener la fractura abierta y maximizar la conductividad.

Los tratamientos previos, empleando solo apuntalante y con el uso de técnicas convencionales no se bombeaban hasta la terminación, y se cuestionaba el potencial de producir económicamente la zona debido a la baja productividad. Después de cambiar el diseño, se realizó un total de 15 tratamientos de fracturamiento con esta metodología; el arenamiento temprano se redujo en un 60% y la productividad de los pozos aumentó en un 80%.

Palabras clave: Fracturamiento hidráulico, híbrido, carbonato/arena, ácido.

Introduction

The Chicontepec basin is located in northern Mexico. It presents a stratigraphy formed by a discordance in this lithological transition, referred to Brecha A. Brecha A is located in the Mendez formation in the upper Cretacic between the Turonian and Cenomanian. This lithological group consists of carbonate gaps and sloping clastic rocks (dolomitized or partially dolomitized). It includes rocks derived from the platform edge; consequently, it contains clasts or reef environment, mollusks, and rudists. The presence of clays as a matrix in these sediments supports the pelagic origin of their sediments. Although the average thickness of this sequence is 200 m in the Poza Rica area, local thicknesses may be greater; in some areas, it is reported to vary from 300 to 1500 m. Its deposit environment is that of a slope, representing the intermediate facies between reef deposits and the open sea. Given the presence of bioclastic, brechoid, and microcrystalline carbonate rocks, it corresponds to potential hydrocarbon-producing and storage rocks, (Nava and Alegría, 2001).

This unit was formed by an intraformational breach with packestone and grainstone fragments, foraminiferal mudstone and microcrystalline dolomites, and calcareous sand, with a greater percentage of shales denominated as calcarenites (Nava and Alegría, 2001).

Typically, hydraulic fracturing treatments involving the use of proppant were performed in this Brecha A formation.

However, the treatment schedules were difficult to complete because of the low capability of the formation to remain open with sufficient fracture widths to continue pumping increased proppant concentrations (greater than 2 or 3 ppg). The lack of conductivity in the formation and the reservoir fluid characteristics (medium to heavy oil with 12 to 15 API) led to poor productivity after the hydraulic fracture treatment. Techniques commonly used in hydraulic fractures to increase proppant placement included increased pumping rates (to decrease fluid leakoff and maintain the fracture geometry longer), higher polymer loadings (to increase fracture widths and to reduce fluid losses in the formation), and decreased proppant size (to enable pumping at higher proppant concentrations and to reach a higher conductivity). However, these changes achieved similar results of early screenout.

Because of the characteristics of the deeper intervals in the Brecha 1 and 2 formations (low permeability ranging from 0.1 to 5 mD, with limestone and dolomite content), an acid fracture treatment was considered as an alternative to increase the productivity of the Brecha A formation wells. The initial acid fracture treatment trials showed production results less than those expected. The primary reason for this failure was that the solubility of the rock with hydrochloric acid was low, as compared to the required ~85% solubility for acid fractures.

Because of the geological and petrophysical characteristics of the reservoir, a different design was used. The new design took into consideration that the permeability range and average porosity are low and that previous hydraulic fracturing treatments could not be completed because of premature screenout. Reviewing the results of local mineralogy, it was determined that an acid system used as a preflush before the proppant fracturing treatment could help to dissolve the carbonate gaps and sloping clastic rocks (dolomitized or partially dolomitized) and to increase the probability of successful proppant placement and completion of the fracturing treatment with this increased etched width. These determinations supported the application of hybrid fracturing treatments using acid and proppant for this formation.

Field application

A study sample of 14 wells determined that the Brecha formation has been treated primarily with hybrid fracturing treatments, which represents 86% of the operations, and 14% that were treated with proppant fracturing and a spearhead acid, **Figure 1**. The average length of the treated interval is 26 m; the total proppant pumped from the initial stages of the learning curve ranged from 100,000 to 150,000 lb of proppant to a later time volume of 200,000 lb or greater proppant mass. The average proppant concentration of the hybrid treatments was 4.6 lb/gal, and the maximum concentration achieved in a fracture was 6 lb/gal. The hybrid fractures were characterized for pumping schedules with HCl volumes from 40 to 60 m^3 of 15% HCl with or without gelling agents. Optimized volumes ranged from 25 to 20 m^3 of acid system. The average pumping rate during the jobs was 32 bpm, **Figure 2**, which required an average hydraulic horsepower of 3,900 HHP, considering 5,000 psi as the surface treating pressure. **Figure 3** through **Figure 5** show treatment charts with the implementation of hybrid and propped treatments in wells A, B, and C.

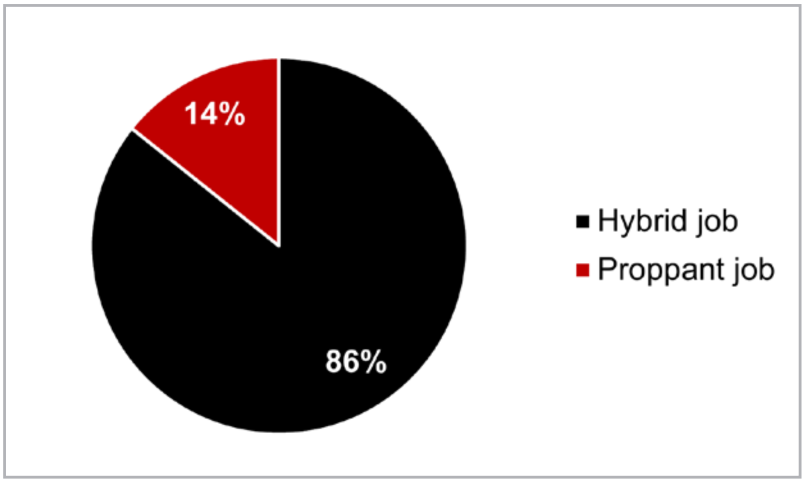

Figure 1. Treatment distribution types in the Brecha A formation.

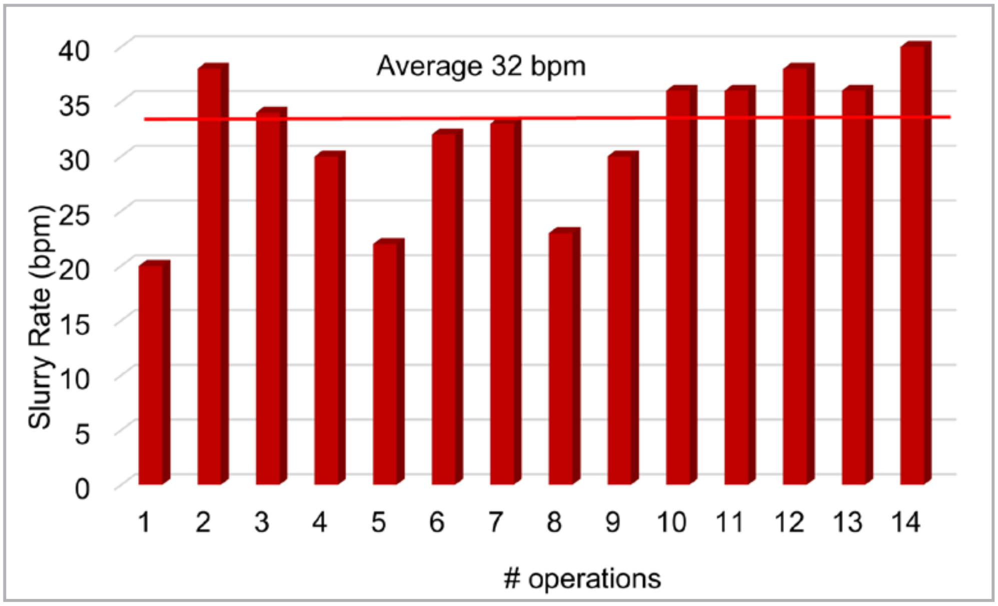

Figure 2. Average pumping rate during the hybrid fracturing treatments.

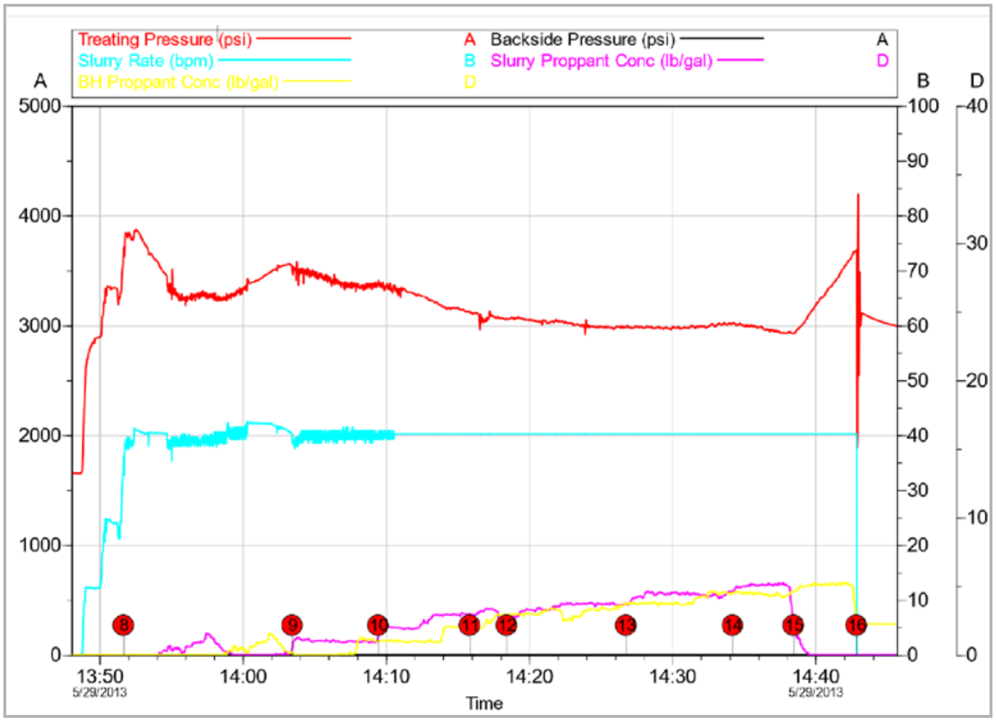

Figure 3. Well A, chart of the hybrid fracture treatment performed.

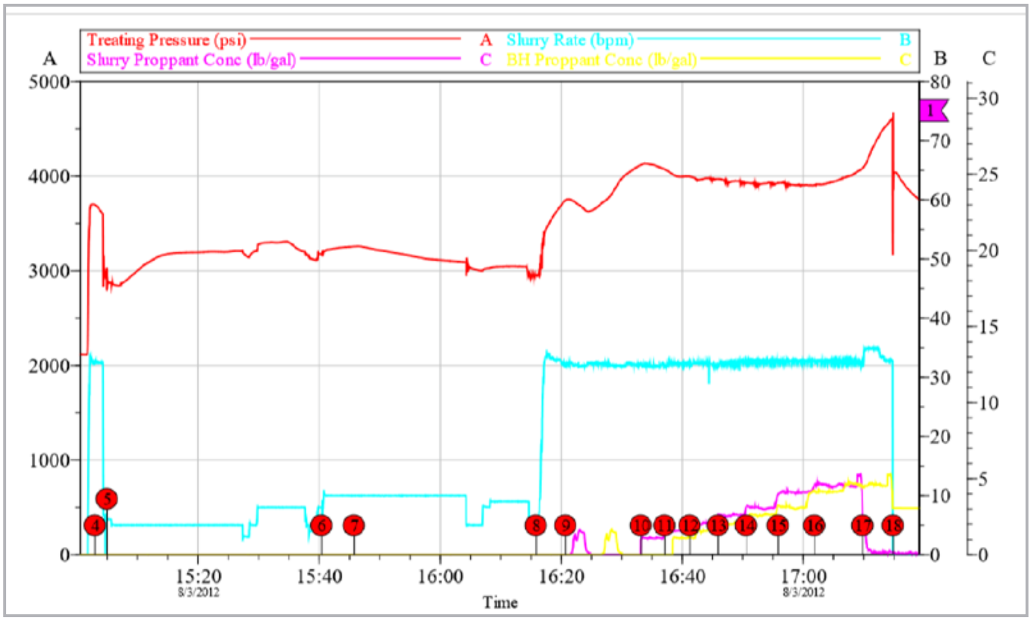

Figure 4. Well B treatment chart for a hybrid fracture treatment.

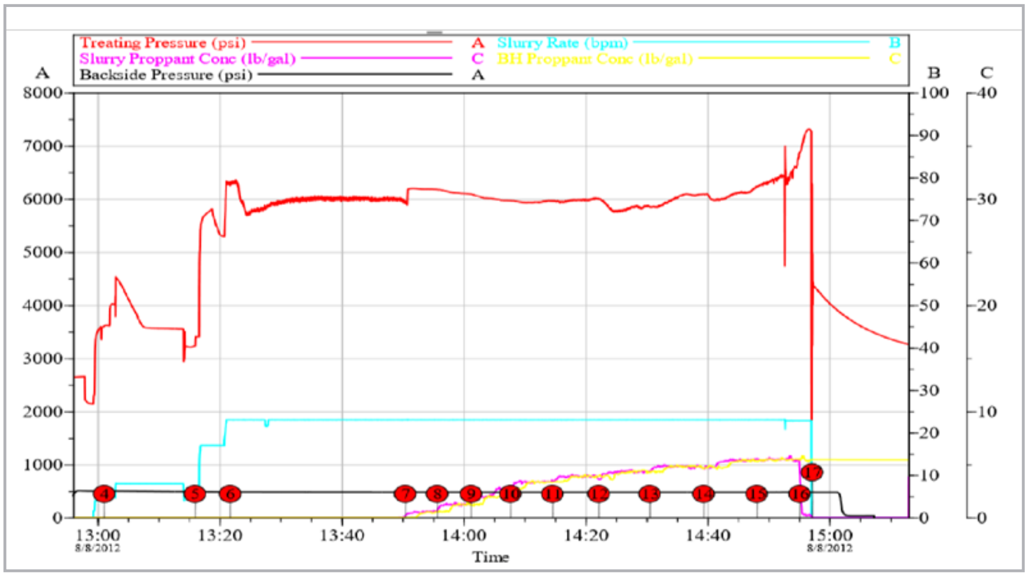

Figure 5. Well C treatment chart of the hybrid proppant treatment.

Case 1: Well A

Well A was completed in the Brecha A formation through 5 in. casing, 17 lb/ft, N-80. A hybrid fracturing treatment was performed to stimulate the interval at 2,329 to 2,341 m; 12 m of the interval was perforated with a 3-3/8-in. gun. The permeability of this zone is 1.8 md, the porosity was 13%; the reservoir pressure was 5,000 psi, and the bottomhole temperature was 98°C. **Table 1** lists the data generated and obtained after the work was completed.

Property	Value
Total fluid used in minifrac	4,788 gal
Average pumping rate (minifrac)	40 bpm
Average surface treatment pressure	3.500 psi
Instantaneous shut-in pressure (ISIP)	2.483 psi
Fracture gradient	0.77 psi/ft
Tortuosity friction pressure	198 psi
Perforations friction pressure	743 psi
Total fluid used during fracture treatment	78.300 gal
Acid	5,283 gal
Sand concentration	1-5 ppg
Total sand volume pumped	1,600 sacks
Average pumping rate (fracture)	40 bpm
Average surface treatment pressure (fracture)	3,043 psi
Propped length	122 m
Propped width	0.43 in
Propped height	57 m
Average conductivity	1,058.5 md-ft
FCD	4.82

Table 1. Well A data.

Figure 6 displays behavior of leak off during the Minifrac performed in Well A, normal leakoff was detected and the near wellbore frictions were distributed with 198 psi to perforations and 743 psi to tortuosity.

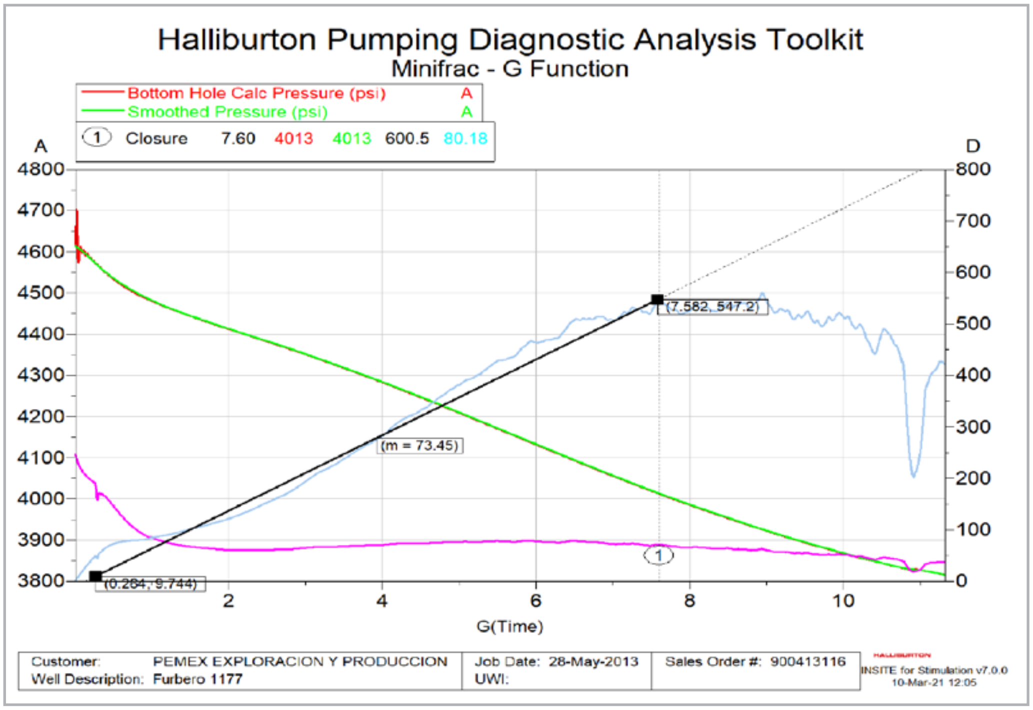

Figure 6. Fall off diagnostic analysis – G Function.

Before this operation, the well produced a maximum oil rate of 200 bopd. After the operation, however, a maximum production rate was reached before a stable production rate is maintained. This result occurs over time as a result of the low reservoir permeability. **Figure 7** shows the production oil rate history of Well A.

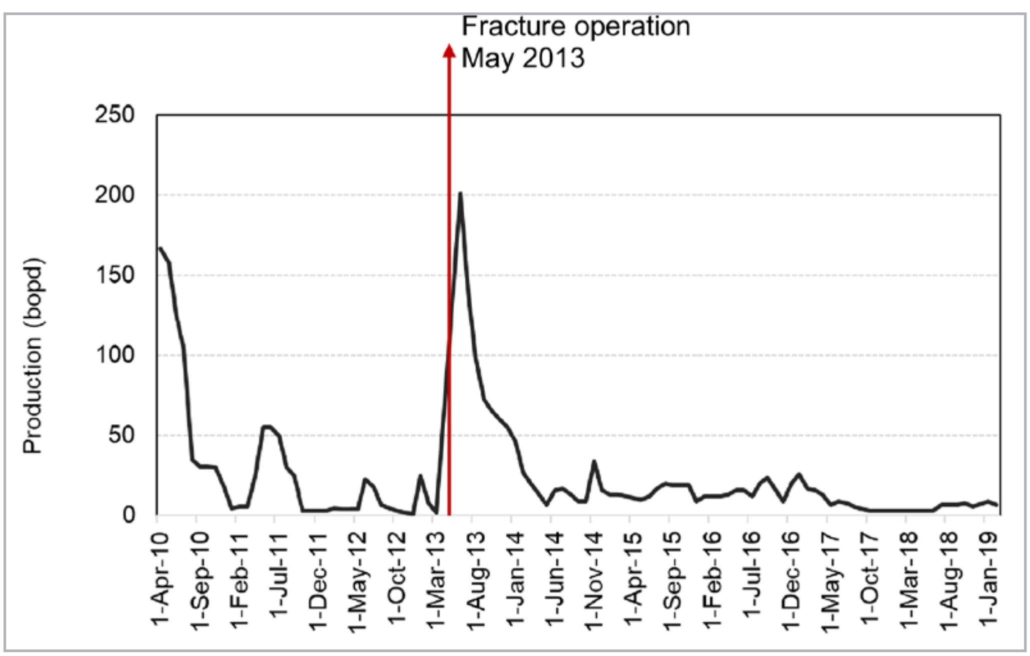

Figure 7. Production history of Well A.

Case 2: Well B

Well B was producing from the Brecha A-1 formation when the hybrid fracturing treatment was performed. This well was completed through 5 in. casing, 17 lb/ft, N-80. The focus of the fracturing treatment was to stimulate the interval at 2,205 to 2,235 m; 30 m of interval was perforated with a 3-3/8-in. gun. The permeability of this zone is 1.07 md, and the porosity was 15.5%. The reservoir pressure was 5,200 psi, and the bottomhole temperature was 105°C. **Table 2** shows the data generated and obtained after this work was completed.

Property	Value
Total fluid used in minifrac	1,890 gal
Average pumping rate (minifrac)	32 bpm
Average surface treatment pressure	2.500 psi
Instantaneous shut-in pressure (ISIP)	2.670 psi
Fracture gradient	0.80 psi/ft
Total fluid used during fracture treatment	67,494 gal
Acid	11,888 gal
Sand concentration	1-6 ppg
Total sand volume pumped	1,250 sacks
Average pumping rate (fracture)	33 bpm
Average surface treatment pressure (fracture)	3,900 psi
Propped length	171.9 m
Propped width	0.168 in.
Propped height	26.55 m
Average conductivity	2,065 md-ft
FCD	25

Table 2. Well B data.

Figure 8 displays behavior of leak off during the Minifrac performed in Well B, normal leakoff was detected and the near wellbore frictions were distributed with 565 psi to perforations and 200 psi to tortuosity. This treatment started with a water control pre-treatment to avoid production of unwanted fluids after the frac.

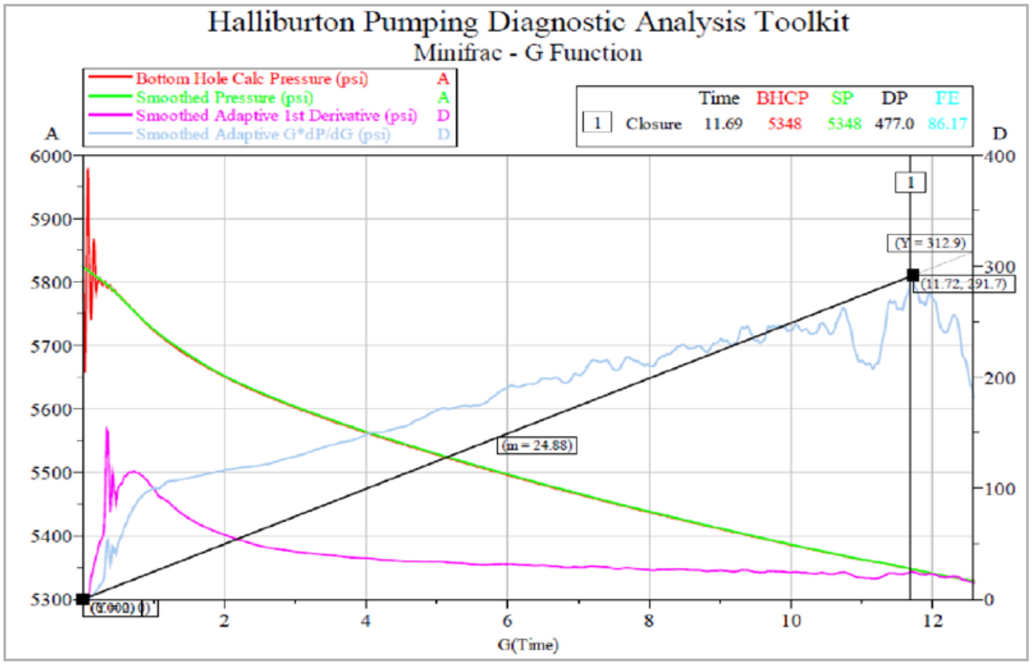

Figure 8. Fall off diagnostic analysis - G Function.

Figure 9 shows the oil production history of Well B. After the fracturing work was performed, an average of 50 bopd was produced in a 2-year period, as compared to 13 bopd produced before the fracture. The operation represents a 3.8-fold production increase.

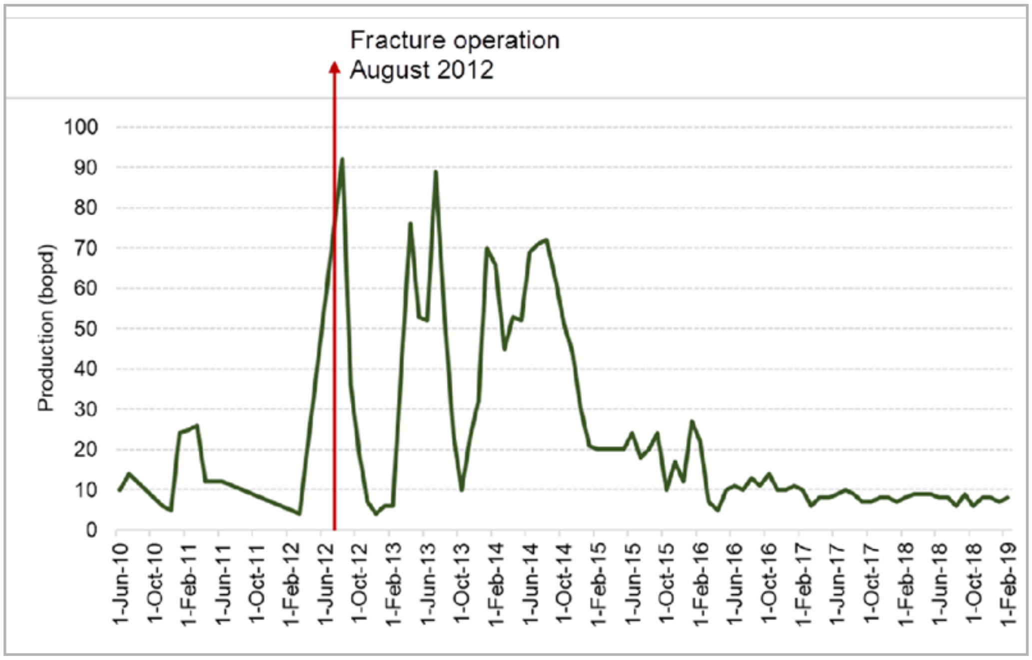

Figure 9. Production history of Well B.

Case 3: Well C

Well C was completed in the Brecha A formation through 5 in. casing, 17 lb/ft, N-80. A hybrid fracturing treatment was performed to stimulate the interval of 2,248 to 2,285 m, for a total formation exposure of 37 m, which was perforated with a 2-1/8-in. gun. The permeability of this zone was 0.784 md, and the porosity was 13.4%. The reservoir pressure was 5400 psi, and the bottomhole temperature of 88°C. **Table 3** shows the data generated and obtained after the treatment was completed.

Property	Value
Total fluid used in minifrac	4,116 gal
Average pumping rate (minifrac)	23 bpm
Average surface treatment pressure	5.200 psi
Instantaneous shut-in pressure (ISIP)	3,014 psi
Fracture gradient	0.87 psi/ft
Total fluid used during fracture treatment	82,950 gal
Acid	5,283 gal
Sand concentration	1-5 ppg
Total sand volume pumped	1,800 sacks
Average pumping rate (fracture)	35 bpm
Average surface treatment pressure (fracture)	5,660 psi
Average propped length	127.9 m
Average propped width	0.084 in
Average propped height	55.16 m
Average conductivity	1,150 md-ft
FCD	3.9

Table 3. Well C data.

Figure 10 shows the oil production history of Well C. After completing the fracturing work, a maximum rate of 47 bopd was documented, with an average rate of 22 bopd afterward.

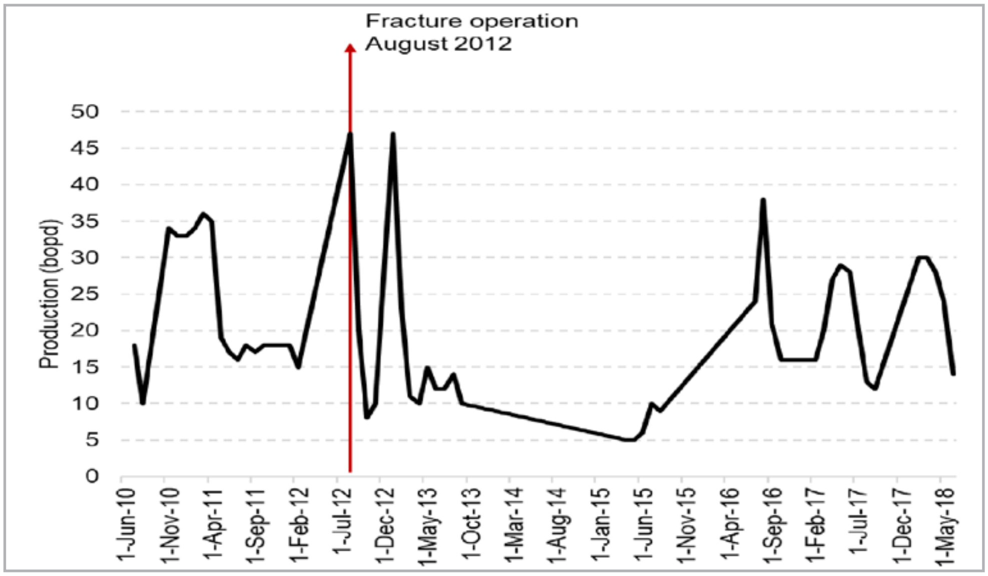

Figure 10. Production history of Well C.

The following table shows a summary of the information, design and production results of the studied wells.

Property	Well A Value	Well B Value	Well C Value
Formation name	Brecha A	Brecha A-1	Brecha A
Interval length (m)	12	30	37
Permeability (mD)	1.8	1.07	0.784
Porosity (%)	13	15.5	13.4
Reservoir pressure (psi)	5,000	5,200	5,400
Reservoir Temperature (°C)	98	105	88
Total fluid used in minifrac (gal)	4,788	1890	4,116
Average pumping rate (minifrac) (bpm)	40	32	23
Average surface treatment pressure (psi)	3,500	2500	5,200
Instantaneous shut-in pressure (ISIP) (psi)	2,483	2670	3,014
Fracture gradient (psi/ft)	0.77	0.8	0.87
Total fluid used during fracture treatment (gal)	78.3	67,494	82,950
Acid (gal)	5,283	11,888	5,283
Sand concentration (ppg)	1-5	1-6	1-5
Total sand volume pumped (sacks)	1,600	1250	1,800
Average pumping rate (fracture) (bpm)	40	33	35
Average surface treatment pressure (fracture) (psi)	3,043	3,900	5,660
Propped length (m)	122	171.9	127.9
Propped width (in)	0.43	0.168	0.084
Propped height (m)	57	26.55	55.16
Average conductivity (md-ft)	1,058.50	2,065	1,150
FCD	4.82	25	3.5
Maximun production rate after treatment (bpd)	200	80	47
Average production rate (bpd)	25	50	22

Table 4. Comparison of well results.

Conclusions

After performing the fracturing treatments, an optimal hybrid treatment for the Brecha A formation was tested. There were 14 hybrid fracture treatments performed in wells before the main fracture (or as a preflush followed by proppant stages) were performed in this formation. The following list summarizes the improvements made to the treatment to complete the fracture treatment as designed and to improve the productivity of the wells.

- 80% of the treatments that were perforated with 2 1/8-in. guns were successful, as compared to 55% of the treatments when perforated with 3 3/8-in. guns.
- Intervals with porosity values of less than 10% had a better probability of treatment completion, as compared with intervals with average porosity values of greater than 10%.
- The combination of hybrid treatment with the Brecha A and Brecha 1 formations open at the same time resulted in early screenout.
- Hybrid treatments with an initial pump rate of less than 30% (of the average) had a 50% chance of premature screenout, as compared to 25% of screenouts observed with initial pump rate greater than 30%.
- All treatments that included proppant size 16/30 presented early screenouts, despite the rate and volume of the initial pump rate or acid used in the treatment.
- Improvements with volumes in hybrid treatments enabled increasing the total proppant pumped from the initial stages of the learning curve, with 100,000 to 150,000 lb of proppant up to 200,000 or greater proppant mass. The average proppant concentration of the hybrid treatments was 4.6 lb/gal, and the maximum concentration achieved in a fracture was 6 lb/gal.
- The early adoption of hybrid fractures was characterized for pumping schedules with HCl volumes from 40 to 60 m^3 of 15% HCl, with or without gelling agents. Optimized volumes ranged from 25 to 20 m^3 of acid system.
- The preferred acid system included a gelling agent to decrease the fluid friction while pumping the fracture treatment. This reservoir presents low permeability; the response after the hydraulic fracture in all cases showed an increase, recording up to a 3.8-fold-increase in production. Over time, however, the production rate declines because of limited permeability formation characteristics.

Comparing both techniques in terms of operation and production, the oil rate of the hybrid treatments was maintained longer than the propped fracturing jobs, as there is more contact area in the reservoir through acid dissolution in the carbonate zone, plus the propped pack which increases the conductivity along the fracture geometry. The Table 4 comparing information and results of the case studies indicates that well B maintained sustained production over time post fracture attributed to the use of higher acid volume and higher proppant volume concentration.

Nomenclature

Bpd	barrels per day
Bopd	barrels of oil per day
Bpm	barrels per minute

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