

Optimization in Completion Wells with a Packerless, Multistage Fracture-Stimulation Method Using CT Perforating and Annular-Path Pumping in Argentina

Juan Carlos Bonapace, Federico Kovalenko, Leonardo Canini y Federico Sorenson,
Halliburton Argentina S.A.

Juancarlos.Bonapace@halliburton.com
Federico.Kovalenko@halliburton.com
Leonardo.Canini@halliburton.com
Federico.Sorenson@halliburton.com

Abstract

This paper documents pinpoint fracturing (PPF) in Argentina. The implementation of this method has resulted in 193 fractures in 22 wells since October 2006.

The PPF method creates perforations by pumping abrasive slurry down the coiled tubing (CT) through a jetting nozzle, while the main treatment is then pumped down the annulus around the CT. Isolation between fracture treatments is accomplished using sand plugs (preferred method) or composite bridge plugs.

This technique has allowed greater selectivity in the stimulation of the areas to be treated; it has also allowed a more aggressive fracture treatment in terms of percent pad and the final proppant concentration because the CT is at the location in case of screen out. In gas fields, it offers the advantage of completing the well without killing it.

Different reservoirs with varying depths, temperature, types of fluid, and petrophysical conditions in the basins Golfo San Jorge and Neuquina were stimulated with different fracture fluids, proppant types, and frac gradients.

The Neuquina basin required fracturing without using a workover rig in oil and gas fields near the community, while significantly diminishing the working times with a reduction in environmental impact and noise generated during the completion. However, the main goal was the reduction of completion times in each well performed in the different basins of Argentina.

Introduction

New hydraulic-fracturing technologies introduced in Argentina not only provide application of new products or processes; but, their versatility allows them to be used in different types of reservoirs and conventional completion practices. On evaluation of different technologies, it is assumed that the selected technology and its application should lead to diminished completion times and cost, as well as improve selectivity and production.

Based on these criteria, it was determined that hydrajet-perforating annular-path treatment-placement and the proppant plugs for diversion (HPAP-PPD) method using CT could fulfill the expected needs. This study shows the application of this in various fields, focusing on each of them to solve problems, such as application in mature fields, gas reservoirs, and low-permeability sands.

The value of HPAP-PPD is well documented in vertical-well completions in many areas in the U.S. (East et al. 2005; Fussel et al. 2006; Helj et al. 2006; Peak et al. 2007), Australia (Gilbert et al. 2005; Beatty et al. 2007) and Russia (Pongratz et al. 2008). The maximum number of individual fracture treatments performed on a single well outside of North America is currently 30, performed on a well in Argentina, although no usage limitation for the method is known.

Description of HPAP with Proppant Plug Diversion (HPAP-PPD)

Using CT, hydrajet perforating, annular-path treatment placement, and proppant plugs for diversion, the (HPAP-PPD) method was introduced to the industry in 2004 (Surjaatmadja et al. 2005). Initial work with the method was related to vertical-well completions. The method

overcame the need for monobore completions because there were no mechanical devices to set inside the casing.

The HPAP-PPD process in a vertical well can be illustrated by **Fig. 1**. The jetting-tool assembly is first positioned at the lowermost intended fracture position (A). An abrasive slurry is then pumped into the CT and jetted out of the tool at high pressures to form perforations (B). At this time, fracturing-pad fluid is pumped through the annulus first, increasing pressure rapidly to cause a fracture to be generated (C). This step is continued for several minutes to establish a good extension, after which the flow rate is increased to the intended fracturing rate and later the proppant slurry started. The tool will be pulled above the perforated interval and the CT tubing rate can then be reduced to a minimum so that it can serve as a dead string in the well for pressure monitoring. This situation also provides a means for rapid corrective action, should an unwanted situation develop.

The proppant slurry is then pumped into the fracture, and when the fracture is extended to satisfaction, an induced screenout is attempted to form a solid pack in the fracture (D), and a “plug” of high-concentration proppant in a viscous gel is left within the wellbore. In some situations, the tubing flow rate is needed for fracture development. In such cases, the tubing rate is maintained throughout the job and only reduced during the tip screenout stage. The CT is then lowered down to the next position while reverse-cleaning (or vacuuming) the sand plug (E), and the process repeats (H). After all planned stimulation stages, a final well cleanout is then performed to wash all the sand from the well.

In **Fig. 2**, the wellhead can be observed, which is necessary for the HPAP-technique application. **Fig. 3** shows the configuration of the bottomhole assembly used in most of the treatments performed.

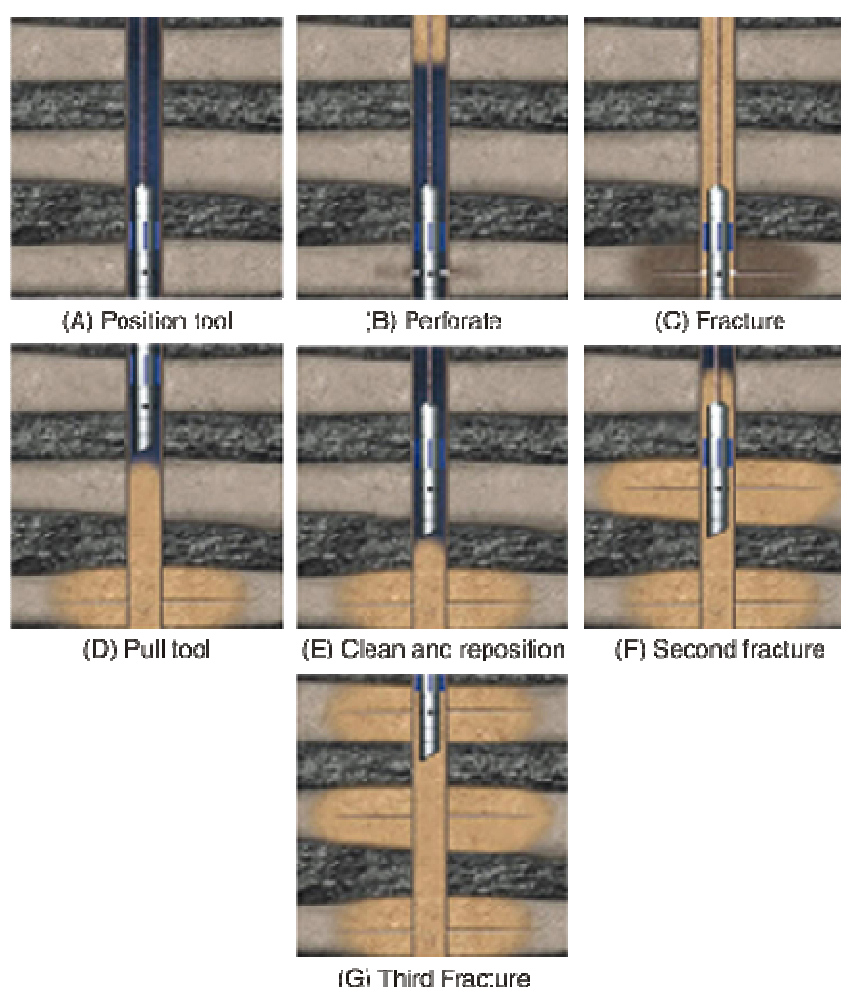


Fig. 1—Annular-path hydrazet fracturing.



Fig. 2—Wellhead with HPAP technique.



Fig. 3—Bottomhole assembly.

Case History—A

Case A belongs to an operator whose field is located in the San Jorge basin. The field is located 85 km west of Comodoro Rivadavia on the west side of the basin. The field is composed of more than 50 fields, which have been exploited since 1959.

Reservoir Geology

The main reservoir consists of middle to late Cretaceous sandstones of the Comodoro Rivadavia formation that average about 20% porosity, 10 to 50 mD permeability, and reservoir pressure of 2,200 to 3,000 psi.

A secondary reservoir consisting of altered tuffaceous sandstones and siltstones is also present in the upper part of the Cretaceous-aged Mina Del Carmen (tuffaceous) formation. Average porosity is about 18%, the permeability is from 5 to 25 md, and reservoir pressure varies from 3,100 to 3,950 psi.

The main hydrocarbon source is the lacustrine shale of the mid to lower Cretaceous D-129 formation. Hydrocarbon traps consist of tilted horst blocks, faulted anticlines, and structurally enhanced stratigraphic pinch-outs.

Oil- and gas-producing layers are generally found in the Comodoro Rivadavia and Mina Del Carmen formations from 200- to 2700-m deep; the thickness of these sands varies from 1.5 to 13 m.

Conventional Completion

The wells are perforated with an 8 3/4-in. diameter drill bit and 5 1/2-in. casing, 15.5 lb/ft, K-55. Well completion is developed through 2 7/8-in. tubing, 6.5 lb/ft, J-55.

Well completion consisted of the following stages.

- CBL rigless logging
- WO rigup
- Wireline perforation of the whole number of the zones with a 4-in. gun, 4 or 6 spf with charges of 22, 32, or 39 g, phase 60–90°
- Swabbing test with mechanical plug and packer of each of the zones (Tbg 2 7/8 in.)
- Hydraulic fractures with plug and packer in a successive manner
- Postfracture-swabbing test
- Final installation
- Well in production

There are some situations where using a double packer is necessary because there are multiple layers in the reservoir and its proximity, generating longer time on location because of a larger number of the round trips of the tubing. Another practice performed in some fields consists of perforations in individual zones, swabbing testing and fracturing, and isolating with mechanical plug, then repeating the sequence.

Stimulations (Hydraulic Fractures)

In 2006, 880 fracture stages were performed. In 2007 there were 910, and in the last year, 860 were registered, averaging 73 fractures on a monthly basis.

The fracture-design criteria are based on experiences gained after more than 6,700 fractures were performed in the field; presently, there are three standard designs. **Table 1** shows the main stimulation parameters.

Table 1—Fracture Parameters

Number of fractures	5
Fracture depth, m	800–2700
BHST, °F	100–240
Fracture gradient, psi/ft	0.57–0.85
Pad, %	38–55
Pump rate, bbl/min	12–18
Wellhead pressure, psi	1,500–6,500
Max proppant concentration, lb/gal	8–10
Fracture fluid	GUAR (borate)-CMHPG (zirconium)
Proppant per fracture, sks	80–600
Proppant type	White sand, RCP, IS bauxite
Proppant size, mesh	12/20, 16/30, 20/40
Post-fracture closure	Forced closure, shut in well
Days fracturing	4

HPAP Completions

This new technique was applied in two fields on nine wells with 90 fracture stages. For this technique development, 1 3/4-in. CT 60 K grade was used. The casing type was modified (5 1/2 in., 17.0 lb/ft, N-80) to obtain a higher yield pressure. In all of the wells, a first bridge plug

was placed below the lowest zone to be used in the depth correlation and reference. The rigup and rigdown of all of the equipment took two days for each well; planning and logistics were of extreme importance for both operations. In **Tables 2** and **3**, several variables can be observed for each of the wells intervened with this technique, as well as the equipment in the well (**Fig. 4**).

The application of this technique was carried out for the first time in Argentina for this operator. The experience was a continuous learning process. While some problems were encountered, they were quickly resolved. Below is a list of the wells and comments unique to that well stimulation program.

HPAP Well 1

There was a six-day delay because of problems with the wellhead; once the bridge plug was set, all six stimulations were carried out in three days. In addition to the fracturing stages, two cuts without fracturing were performed to evaluate the kind of perforations being achieved.

HPAP-Well 2

There was a five-day wait because of water supply issues, then all 12 stimulations were completed in four days.

HPAP-Well 3

There was a three-day delay caused by problems with MCCL and bridge-plug setting. Afterward, all 14 fracturing stages were completed in seven days.

HPAP-Well 4

There was a one-day delay caused by surface-line freezing problems (climate condition); then all eight fractures were completed in four days.



Fig. 4—Frac crew on location.

Table 2—Well Data Summary

Well	HPAP-1	HPAP-2	HPAP-3	HPAP-4	HPAP-5
Number of fractures	6	12	14	8	12
Fracture depth, m	2510.0–1745.5	2121.0–1008.0	2084.0–1136.5	2142.3–1709.6	2541.0–1679.5
BHST, °F	210–167	127–188	133–186	165–189	164–212
Fracture gradient, psi/ft	0.88–0.66	0.86–0.58	0.78–0.59	0.77–0.71	0.83–0.61
Pad, %	45–54	47–53	45–50	52–56	53–61
Pump rate, bbl/min	13.5–15.5	12.4–18.0	13.2–15.0	14.0–16.9	13.9–15.9
Wellhead pressure, psi	2,000–3,780	1,200–3,000	1,100–3,800	1,170–3,800	1,380–4,200
Fracture fluid	Guar (borate)	Guar (borate)	Guar (borate)	Guar (borate)	Guar (borate)
Proppant per fracture, sks	138–227	160–720	96–519	114–413	134–397
Proppant type	IS bauxite-Sand	Sand	Sand	RCP-Sand	IS bauxite-RCP
Proppant size, mesh	20/40	12/20, 16/30, 20/40	12/20, 16/30, 20/40	16/30, 20/40	16/30, 20/40
Total frac proppant, sks	1115	3721	2906	2264	2710
Screen-outs	No	No	Yes, 2	Yes, 2	Yes, 5
Depth Correlation	Bridge plug, 2	MCCL	Bridge plug, 2	MCCL	MCCL
Jetting-breakdown	Sand	Sand + acid	Sand + acid	Sand + acid	Sand + acid
Sand plugs	4	11	11	7	11

Table 3— Well Data Summary

Well	HPAP-6	HPAP-7	HPAP-8	HPAP-9
Number of fractures	10	11	8	9
Fracture depth, m	2114.0–1714.0	2508.0–1681.5	2562.0–2149.5	2244.0–1446.5
BHST, °F	166–188	164–210	190–213	151–195
Fracture gradient, psi/ft	0.86–0.72	0.85–0.58	0.97–0.63	0.76–0.62
Pad, %	52–58	50–56	47–55	51–56
Pump rate, bbl/min	14.3–18.3	13.3–15.2	14.3–15.7	14.0–15.4
Wellhead pressure, psi	1,800–3,200	1,190–4,300	2,050–4,110	1,630–2,800
Fracture fluid	Guar (borate)	Guar (borate)	Guar (borate)	Guar (borate)
Proppant per fracture, sks	134–459	134–314	82–270	114–206
Proppant type	Sand, RCP	IS bauxite, Sand	IS bauxite, RCP, Sand	Sand
Proppant size, mesh	16/30, 20/40	16/30, 20/40	16/30, 20/40	20/40
Total frac proppant, sks	3109	2289	1143	1322
Screen-outs	Yes, 2	Yes, 1	Yes, 1	No
Depth Correlation	MCCL	Bridge Plug, 2	MCCL	MCCL
Jetting-breakdown	Sand + acid	Sand + acid	Sand + acid	Sand + acid
Sand plugs	9	8	7	8

Time Comparative Analysis

To evaluate HPAP methodology, the following comparative analysis with offset wells where completion was carried out in a conventional way compared to HPAP wells is presented. Because of the nature of the reservoir, not all the wells have the same stimulations quantity;

because of this, it is of extreme importance to consider the quantity of stimulations when evaluating time and efficiency of said time.

It is important to point out that for wells completed in a conventional way, the time considered is taken from the beginning of the first stimulation to the end of the last fracture stage; this has been expressed in days (24 hours).

For HPAP completions, the same criterion was taken, considering the beginning time as the first stage of jetting; not withstanding this, it must be said that the time used to perform these operations was 12 hours because the operations were rigless and were carried out in daylight with a one-shift staff.

Fig. 5 shows the time results for a set of 21 conventional wells (offset) and 9 wells with the HPAP technique used. It can be observed that for Well-7, where 10 fracture stages were carried out (blue) conventionally, 0.9 days per fracture were required, and the HPAP-6 (red) only required 0.4 days per fracture; the most contrastive case can be observed in the wells located in the Well-1 graph and HPAP-9, where 9 stimulations, 1.67 (blue) and 0.22 (red) days per stage respectively, were necessary.

It is important to point out the best results achieved in each of the wells where the HPAP technique was used, denoting perseverance in the performance of at least three fractures within 12 operative hours.

Listed below are the best performances

- HPAP-1—3 Frac stages in 7:30 hr
- HPAP-2—3 Frac stages in 5:20 hr
- HPAP-3—3 Frac stages in 8:05 hr
- HPAP-4—3 Frac stages in 8:00 hr
- HPAP-5—3 Frac stages in 6:30 hr
- HPAP-6—4 Frac stages in 10:50 hr
- HPAP-7—3 Frac stages in 6:05 hr
- HPAP-8 —4 Frac stages in 10:00 hr
- HPAP-9—5 Frac stages in 9:50 hr + 4 frac stages in 9:10 hr (**Fig. 6 and 7**)

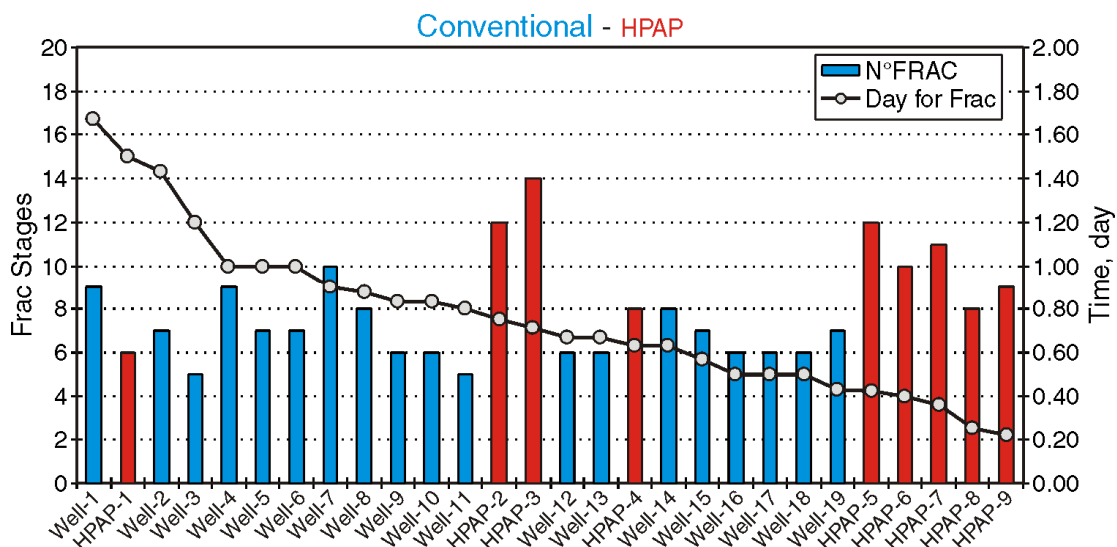


Fig. 5—Time comparison.

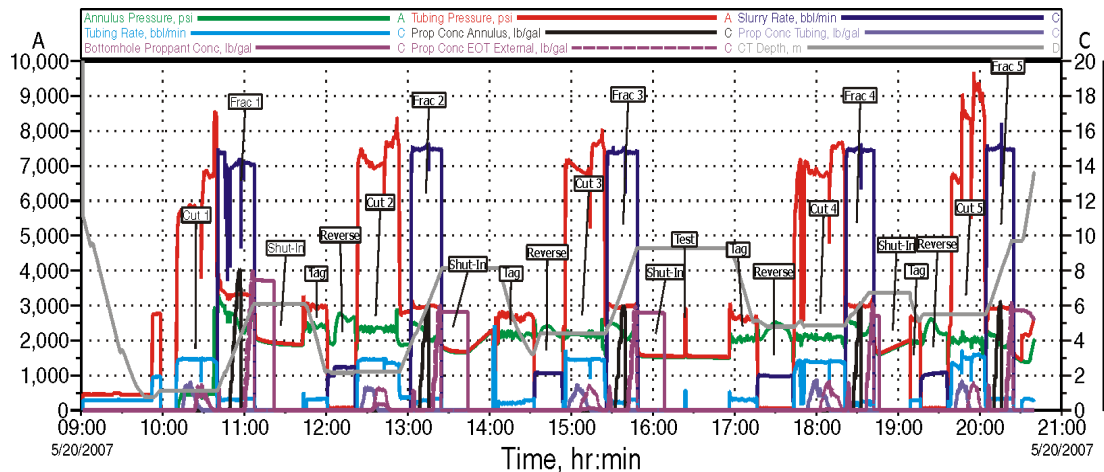


Fig. 6—Well HPAP-9, first day operation.

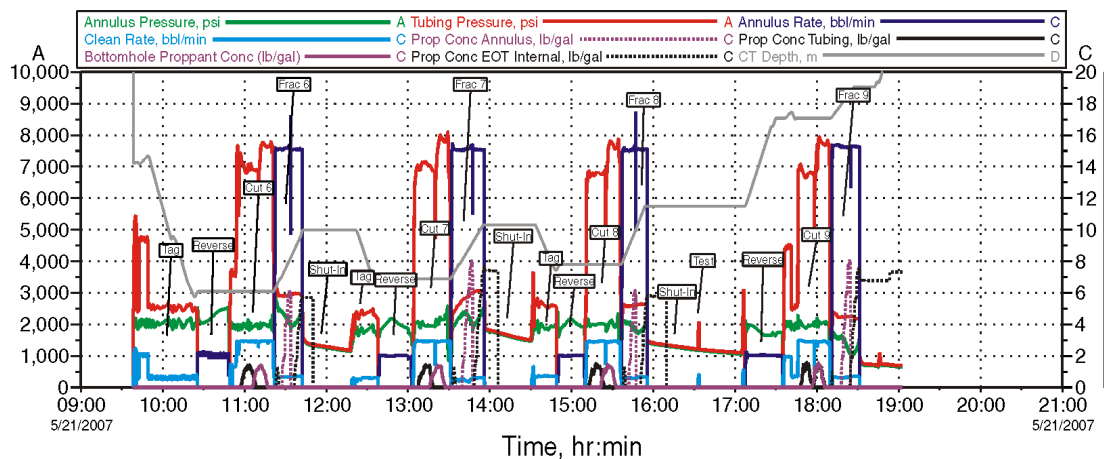


Fig. 7— Well HPAP-9, second day operation.

Case History—B

The second case belongs to an operator whose field is located in the Neuquina basin. The field is located 35 km to the west of the city of Neuquén and is composed of two fields that have been exploited by the operator since 1991.

Reservoir Geology

The field comprises three formations (Table 4). The Molles formation is subdivided into three different sections. The superior section is characterized by the presence of sandy bodies and conglomerated with shale intercalations and tuffaceous levels. Underneath is a succession of shales with intercalations of fine sands; to conglomerate the relationship, sand/clay diminishes toward the inferior levels; this sequence would correspond to deep-sea deposits with a presence of submarine fans, where sandy bodies were deposited caused by turbidity currents.

The Lajas formation was formed by fine- and medium-sized sandstones of small thicknesses and conglomerated sandstones and fine conglomerates separated by shale transitionally changing into the Molles formation's black clays, which belong to coastal marine deposits, deltas, and beaches.

The Tordillo formation is composed of fine and average sandstones and even conglomerates with small shale intercalations; it belongs to continental deposits associated with fluvial systems.

Table 4—Main Formation Parameters

Formation parameters	Molles	Lajas	Tordillo
Depth, m	2300–3000	1950–2300	1330–1950
Formation thickness, m	700	350	120
Fluid reservoir, API	Gas	Gas	Gas, oil (40)
Water saturation, %	24–45	38–40	35
Porosity, %	8.5–12.0	11.0–14.0	9.0–17.0
Permeability, mD	0.08–0.5	0.2–0.65	0.25–2.0
Pore pressure, psi/ft	0.30–0.49	0.21–0.37	0.16–0.28

Conventional Completion

Conventional completion is performed in cased wells with casing that is 5 ½ in., 15.5 lb/ft, K-55. The perforation methodology is a pseudo limited-entry technique because the goal is to cover several zones with only one treatment; to reach such an objective, it is common to perforate with a 4-in. gun with 32 g to 2 spf charges, according to the zones.

Well completion consists of the following stages.

- WO rigup
- Integrity-casing test with 3,000 psi
- CBL logging, evaluation, and corrective isolation performance whenever necessary—new CBL log
- First-interest zone perforation
- Hydraulic fracture (tree saver utilization)—leaving a sand plug
- Sand plug depth verification with wireline
- The sequence is repetitive until all zones to be treated are complete
- Well cleaning with CT
- Packer fixing with wireline
- Production installation
- Final well test

This methodology is used only in a new well's termination, and the operator has been applying this completion technique for more than ten years. The service company developed a stimulation campaign in 2004, 2005, and 2006 on 25 wells and 107 fracture stages. Along the campaign, it was possible to perform two stimulations in 11 hours on only one occasion.

Stimulations (Hydraulic Fracture)

For each well completion, it is common to perform between four and seven fractures, requiring at least one day for the performance of each, as long as no problems occur in the sand-plug location. The stimulations are performed only in daylight (12 hours), for security reasons, as well as for CO₂- and fluid-supply logistics.

In the Lajas and Tordillo formations, a proppant combination was used. Sand was used in the first concentrations and IS bauxite in the second, which was placed in the surroundings of the perforation. Maximum proppant concentrations in foam were 5.0-lbm/gal.

Table 5 shows the main stimulation parameters performed in the field for each of the formations.

Table 5—Fracture Parameters

Fracturing Parameters	Molles	Lajas	Tordillo
Fracture depth, m	2210.0–2880.0	1820.0–2260.0	1580.0–1940.0
No. of perforations	3–7	3–11	3–10
BHST, °F	173–203	156–175	145–162
Fracture gradient, psi/ft	0.51–0.74	0.45–0.78	0.46–0.71
PAD, %	32.5	30.5	30.5
Foam pump rate, bbl/min	24.0–31.0	21.0–26.0	17.0–22.0
Wellhead pressure, psi	2,000–3,970	1,300–3,540	700–2790
Fracture fluid	CO ₂ foam, qlt 65 to 55%	CO ₂ foam, qlt 65 to 55%	CO ₂ foam, qlt 65 to 55%
Proppant per fracture, sks	290–860	195–1300	310–860
Proppant type	IS bauxite	Sand + IS bauxite	Sand + IS bauxite
Proppant size, mesh	16/30	16/30	16/30

HPAP Completion

For said well, 1 ¾-in. 60-K grade CT was used, and the setting depth was carried out with MCCL. Stimulation performances (foam frac) with this technique showed a major complexity for the following reasons: (1) it was necessary to count on CO₂ logistics, which is why a 155-ton storage capacity was used on location and 255 tons were required for the entire operation, and, (2) it was necessary to avoid leaving energized fluid (foam) in the well, which would make sand-plug setting difficult and with subsequent time delay.

The sand plug was designed with double volume and a 9.5-lbm/gal concentration with the goal of setting the exceeding volume in the formation at the perforation mouth at the same time of the frac rate, hoping screen-out would diminish. **Table 6** illustrates the main registered variables in the operation. **Fig. 8** shows the equipment seen on location.

There were problems at the beginning of the first fracture, which resulted in delays. There was poor communication between the well and the formation after performing the cut, so it was decided to repeat the cut on two more occasions at different depths. Because the situation was the same, the well depth was checked up with wireline; their location was correct, and finally the zone was perforated with conventional gun. The subsequent analysis showed the zone had a scarce development (2.5 m); the sand was dirty sandstone (with shale intercalations), which would have contributed to the screen-out during the operation.

Table 6—Main Data HPAP Technique

Fracturing Data, HPAP	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7
Fracture depth, m	1959.5	1932.5	1816.0	1672.0 + 1773.0	1719.5	1703.0	1650.5
BHST, °F	162	161	155	153	151	150	148
Mini Frac frac gradient, psi/ft	Yes (0.74)	Yes (0.74)	No	No	No	Yes (0.65)	No
PAD, %	33.3	41.5	32.0	29.0	25.5	25.5	26.5
Foam pump rate, bbl/min	14.4	15.0	145	16.2	15.0	15.5	15.3
Wellhead pressure, psi	2,890	2,860	2,830	2,240	2,760	2,500	2,080
Fracture gradient, psi/ft	Not available	0.75	Not available	0.73	Not available	0.72	Not available
Fracture fluid	CO ₂ foam/ qtl 65–60%	CO ₂ foam/ qtl 65–60%	CO ₂ foam/ qtl 65–60%	CO ₂ foam/ qtl 60–55%	CO ₂ foam/ qtl 60–55%	CO ₂ foam/ qtl 65–60%	CO ₂ foam/ qtl 60–55%
Proppant type	IS bauxite	IS bauxite	IS bauxite	Sand + IS bauxite	Sand + IS bauxite	Sand + IS bauxite	Sand + IS bauxite
Proppant size, mesh	16/30	16/30	16/30	16/30	16/30	16/30	16/30
Proppant per fracture, sks	99	99	283	603	187	228	357
Screen-outs	Yes	No	Yes (induced)	No (induced)	Yes (induced)	No (induced)	Yes (induced)
Jetting breakdown	Sand + Acid / Gun	Sand + Acid	Sand + Acid	Sand + Acid	Sand + Acid	Sand + Acid	Sand + Acid
Sand plugs	Yes	Yes	Yes	Yes	Yes	Yes	No

**Fig. 8—Frac crew on location.****Comparative Time Analysis**

For HPAP-methodology evaluation, a set of offset wells performed by the service company were considered by this operator between 2004 and 2006 using conventional completions. It is important to point out that the operation time to perform the stimulations was 12 hours in daylight, either for wells completed in a conventional way or for those completed with the

HPAP technique. The same criterion was used from the beginning for the first stimulation until the last fracture stage; this has been expressed in days (24 hours).

Fig. 10 shows the time results for 19 conventional wells (offset) and one well where the HPAP technique was used. It can be observed that for Well-16, where 7 fracture stages were performed (blue) in a conventional way, 1.0 day per fracture was necessary, while 0.86 day per fracture was required for the HPAP-1 (red). Time reduction observed between Well-1 and Wells-13 through 19 was a result of the experience developed in this kind of conventional completion; notwithstanding, such time could be improved only with HPAP methodology. Another important contrast to point out is the best result achieved in the wells where the HPAP technique was applied compared to the 19 wells completed in a conventional way. The comparison is listed below.

- HPAP-1—3 Frac stages in 8:20 hr (**Fig. 9**)
- Well-16—2 Frac stages in 11:00 hr

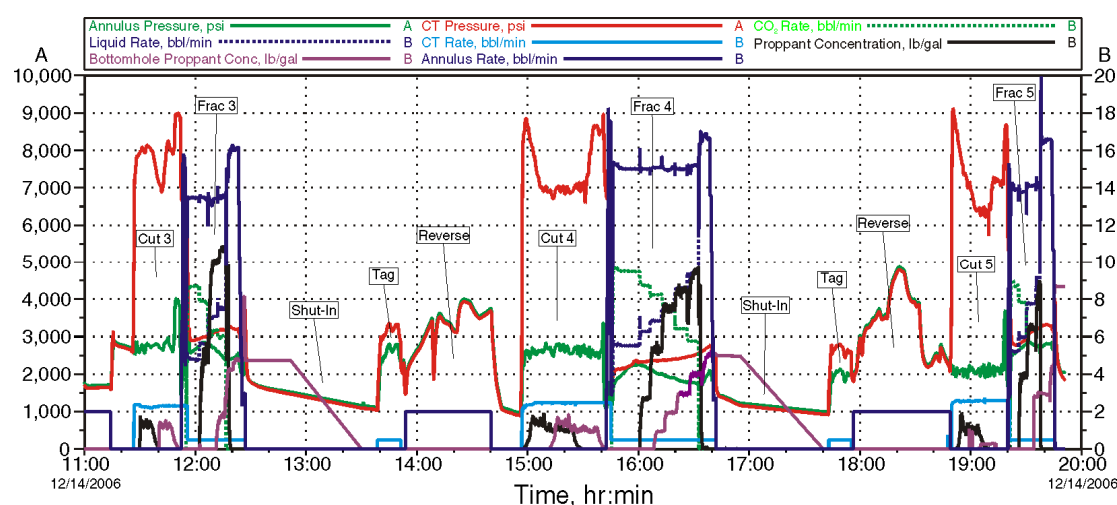


Fig. 9—Well HPAP-1 CO₂ foam frac.

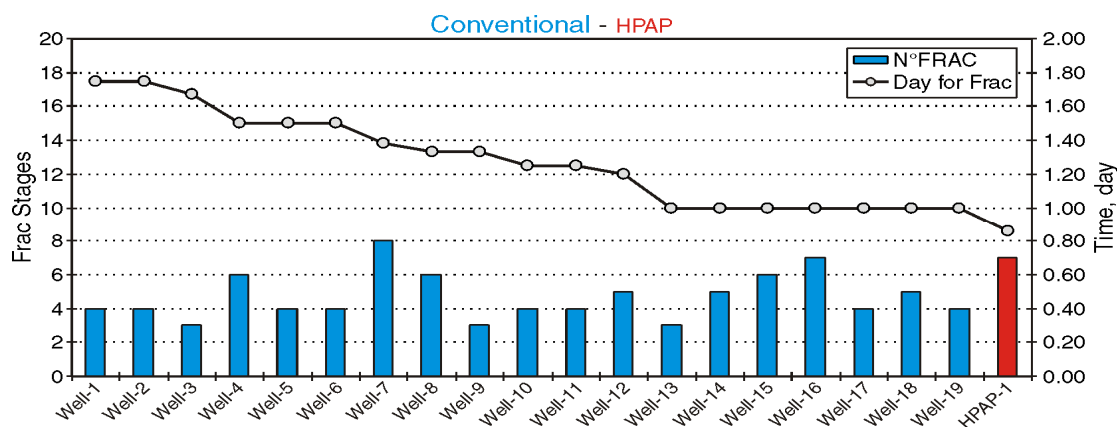


Fig. 10—Time comparison.

Case History—C

The third case corresponds to an operator, whose field is situated in the Neuquina basin, which is located 15 km west of the city of Neuquen and has been exploited since 1977.

Reservoir Geology

This field comprises three main gaseous formations with different petrophysical characteristics. The Molles formation is of low permeability and elevated pressure. The Lajas formation has smaller pressure but has more permeability; in certain depths, it is also depleted. The Quintuco formation is from a calcareous origin with sandstone percentage, normal pressures, and can have fissured rocks (**Table 7**).

Table 7—Main Formation Parameters

Formation Parameters	Molles	Lajas	Quintuco
Depth, m	2500–3500	2000–2500	1800–2100
Porosity, %	6.0–12.0	8.0–12.0	12.0–16.0
Permeability, mD	0.02–0.2	1.0–5.0	0.05–0.5
Pore pressure, psi/ft	0.45–0.61	0.23–0.35	0.37–0.45

Conventional Completion

Historically, this reservoir is completed by fracturing several zones together. This kind of perforating is performed with 4-in. gun, 4 spf with 32 g charges. The casing is 5 ½ in., 17.0 lb/ft, N-80. The field is located next to an urban area, which limits the work schedule to fracturing only in daylight. The treatment designs consist of IS proppant, 60 klbs average per formation meter. Selected zones are fractured as a unit using a pseudo limited-entry technique, which allows fracturing stage sizes of 1000 to 1500 klbs, on average.

The isolating method was alternated between mechanical plug fixed with cable and sand plug, depending on the distances between the fractures. After completing each frac stage, well cleaning was performed and it was isolated with a mechanical plug to avoid a possible cross flow produced by pressure differences among the formations, whether in the completion of the superior zones, or during the final well-cleaning process.

Completion with HPAP

The HPAP technique was carried out with a 1 ¾-in. 90-K grade CT; after introducing said technology, a more accurate sand selection to be fractured was performed, obtaining smaller size fractures between 600 and 800 klbs. Likewise, the well-cleaning process was (as above) was used after finishing each frac stage and isolating the fracture with mechanical plugs, although time savings for the performed fractures were produced in each stimulated zone.

The tool-depth setting was performed taking as reference the mechanical plug to isolate formations. In the completion with HPAP, two screen-outs were observed during flush of Fractures 2 and 4. The advantage of having CT within the well permitted sand washing without taking further time and additional cost and allowed fracturing the following day. **Fig. 11** shows equipment on location.



Fig. 11—Frac Crew on location.

Comparative Time Analysis

Two neighboring wells were stimulated by the service company to compare the conventional and the HPAP methodologies. **Table 8** shows the main comparison parameters.

In Table 8 below, it can be seen that in the well fractured with HPAP, more fractures of smaller size were performed in a smaller reservoir grouping, focusing the treatments in the zones of interest and respecting the design criterion.

The time used for the performance of each treatment is detailed in **Figs. 12** and **13**. In both cases, there is a time restriction, so fracturing takes place in daylight because of well proximity to the urban zones. The working days vary between 12 to 16 hours, depending on the season.

The well completed conventionally required 11 days to perform 6 treatments, carrying out only one per day. A formation change was produced between Fractures 3 and 4 without cleaning said zones. Mechanical plugs were used in Fractures 1, 2, and 4 to isolate the zones (**Fig. 12**).

In **Fig. 13** is timing for the well in which the HPAP technique was used, where Stages 1 and 2 were performed on the same day, just as Stages 5 and 6, taking 7 days to perform 7 fractures, including well cleaning and fixing a mechanical plug between Stages 3 and 4, which is where the formation change was produced. Fracturing frequency was 1.5 fractures per day.

The best result achieved was in the well completed using the HPAP technique, performing more than one fracture per day (2 frac stages in 7:30 hr) (**Fig. 14**).

Table 8—Fracturing Methodology

Fracturing Methodology	Conventional	HPAP
Completion date	March 2008	August 2008
Fractured formations	Molles Sup (3), Lajas (3)	Molles Basal (3), Molles Sup (4)
Depths, m	3040–2090	3020–2630
Number of fractures	6	7
Proppant pumped, sks	6989	4370
Proppant per fracture, sks	1165	624
Net Pay, m	117	78
Sks/m Pay	60	55
Average fracture gradient	0.67	0.72
Fracture fluid	Guar, borate	CMHPG, zirconium
Proppant agent	IS bauxite 20/40, 16/30	IS bauxite 20/40
Screen-outs	0	2
Injected volume, m ³	1166	1148
Average rate, bbl/min	25	19
Flowback between formations	No	Yes
Bridge plugs	3	2
Sand plugs	3	5
Days fracturing	10	6

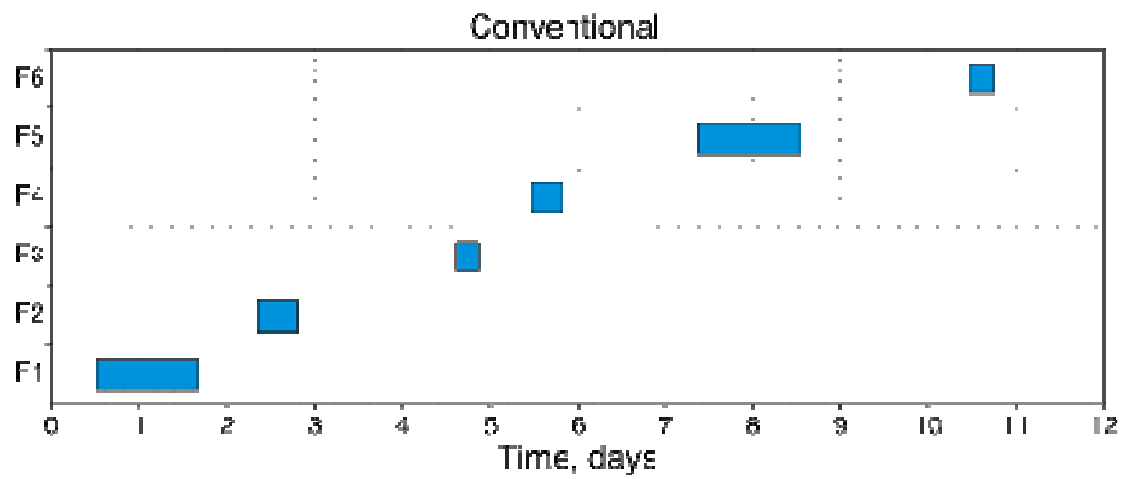


Fig. 12—Conventional time.

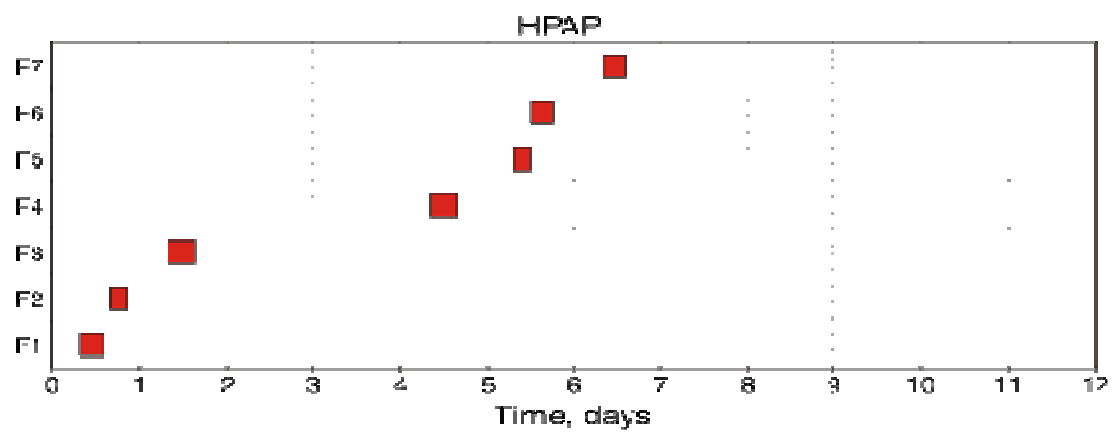


Fig. 13—HPAP time.

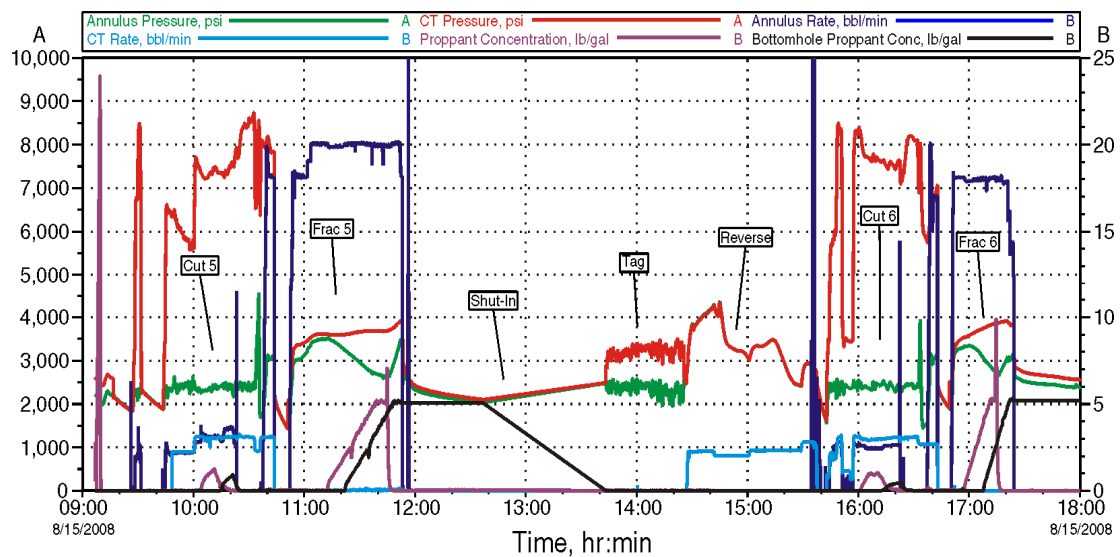


Fig. 14—Well HPAP, CMHPG frac.

Conclusions

Case A

- HPAP wells 2, 3, 4, and 6 were developed in a field where conventional completions generally use double packers or are carried out in separate steps (perforation-fracture mechanical isolation). Using the HPAP technique reduced time for the completion and allowed selective fracturing of the productive zones.
- HPAP wells 1, 5, 7, 8, and 9 were developed in the geographic area at a deeper depth and in a reservoir with elevated fracture gradients. Conventional completions in this environment have shown that, on more than one occasion, certain intervals have not been stimulated because of the lack of necessary means (more resistance tubing). In some situations, the same completions have been stimulated with elevated work pressures. Using the HPAP technique permitted zone fracturing with less pressure, which would not have been possible in a conventional treatment, resulting in cost reductions due to less horsepower).
- For all the HPAP wells, a meaningful time reduction was observed for stimulation performance compared to the conventional completions; nine fracture stages were carried out in 19 operative hours.

Case B

HPAP technique allowed zones to be stimulated in a more selective way; the work methodology reduced stimulation treatment times over present and historical methods for conventional completions. For the first time, the operator reached the performance of three fractures in just 8.20 operative hours.

Case C

Time savings gained have allowed more days for well and formation cleaning without incurring excessive costs for the operator and minimizing the injected-water contact time with the formation, reducing the damage produced in a gas reservoir.

Nomenclature

IS	= Intermediate strength
BHST	= Bottomhole static temperature
RCP	= Resin coated proppant
MCCL	= Mechanical casing collar locator
SPF	= Shoot per foot
CT	= Coiled tubing
CBL	= Cement bond logging
WO	= Workover
SKS	= Sacks

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