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Water Management for Tight and Shale Reservoir: A Review of What Has Been Learned and What Should Be Considered for Development in Argentina

Juan Carlos Bonapace, Halliburton

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Abstract

This work builds on Bonapace et al. (2015), specifically discussing shale reservoir information related to several tight reservoirs in Argentina.

Hydraulic fracturing has been ongoing in Argentina since the 1960s. The first treatments were performed using oil-based fluids. Throughout the years, new water-based fluids were introduced, as well as alcohol-water mixture fluids to foams, based on the reservoir requirements, economics, and safety and environmental issues. Currently, more than 95% of hydraulic fractures performed in the country are performed using aqueous-based fluids.

In the last 10 years, exploration and development has begun for tight gas reservoirs and more recently several shale plays. To achieve commercial production, this type of reservoir requires extensive hydraulic fracturing applications which use large volumes of water. From 2004 to present, various exploration techniques have been performed in different reservoirs, such as tight formations at Lajas, Punta Rosada, Mulichinco (Neuquén Basin); Potrerillos (Cuyo Basin); D-129 (Golfo San Jorge Basin) and shale plays at Los Molles, Vaca Muerta, Agrio (Neuquén Basin), Cacheuta (Cuyo Basin), and D-129 (Golfo San Jorge Basin).

This paper discusses aspects of water logistics necessary during the well completion phase, fracture treatment designs applied within these various unconventional reservoirs, and laboratory studies performed on flowback and produced waters to help evaluate their potential for use and/or reuse. The primary focus here will be related to various parts of the water cycle for these projects.

- Stimulation and water sources are presented as detailed information concerning the type of stimulation performed in these reservoirs, volume of water, treatment types, fracturing fluids, additives used, and physical-chemical characteristics of various freshwater sources used.
- Logistics are discussed for water storage and transport for single and multiple well pads.
- Reuse of flowback and formation water addresses laboratory testing of various flowback and formation water and/or blends (freshwater and flowback water), treated and untreated including:
  - Physico-chemical characteristics of water (flowback and produced) from various wells.
  - Formation sensibility testing with flowback water from various tight and shale formations and usage possibilities.
  - Impact on proppant packs of floculants generated in nontraditional waters at various pH values..
  - A new low-residue CMHPG-metal crosslinked fracturing fluid formulated using no traditional water, i.e., untreated with high total dissolved solids (TDS).

Introduction

Well stimulation by means of hydraulic fracturing has been widely used for producing oil and gas reservoirs in Argentina since the 1960s. This stimulation technique has been applied in the five hydrocarbon producing basins **(Fig. 1A)** and in a variety of formations and types of reservoirs, such as conventional, tight, and more recently in shale (source rocks). The hydraulic fractures created in Argentina present a variety of conditions and challenges related to depth (from 300 to 4500 m), bottomhole temperature (BHT) (100 to 300°F), reservoir pressure (from subnormal to overpressure), formation permeability (high, medium, low, and ultra-low perm), multilayer reservoirs, and wells that target multiple zones for completion.

Throughout the years, there have been noticeable changes to the types of fracturing treatments and wells in which fracturing fluids are used, from oil-based systems, alcohol mixtures, and foams, to water-based fluids currently used. The steady increase in drilling activity and therefore well completion and stimulation has led to increased water consumption; therefore, alternatives have been sought to help minimize this impact in certain basins. Bonapace et al. (2012) documents the use of produced water for use in a fracturing fluid in the Gulf of San Jorge (GSJ) Basin, managing to replace 55% of freshwater consumption.

Initially, the first treatments in unconventional reservoirs (2004) were in tight formations in which several operators began exploration; the development phase was primarily in the Neuquén Basin, focusing on the Lajas, Punta Rosada, and Mulichinco formations. Some treatments were performed in the Potrerillo formation (Cuyo Basin) and, in the last five years, two operators have begun to evaluate the D-129 formation (GSJ basin).

Bonapace et al. (2015) presents the experience developed in a shale reservoir. This paper presents an update on stimulations performed in this type of reservoir, providing extensive information based on the type of well (vertical-horizontal). Discussion of the experience is primarily related to water management in these mentioned unconventional plays during the completion of more than 100 wells (>500 hydraulic fracturing treatments). Furthermore, laboratory studies conducted for flowback water (treated and untreated) to assess its use and applications are presented.

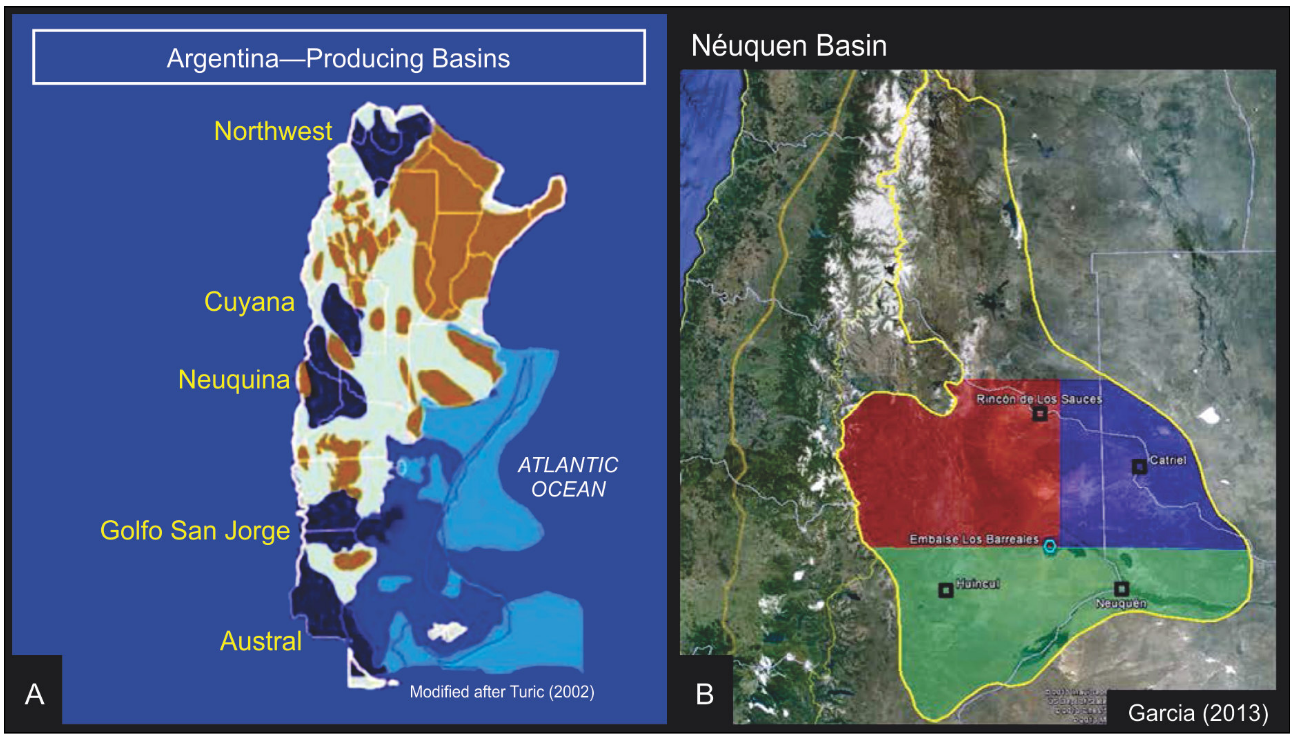

Fig. 1—(A) Map of five Argentina hydrocarbon producing basins; (B) Neuquén Basin geographical subdivision.

Water Sources and Stimulation

These Argentina Producing basins have a history of development of conventional reservoirs and corresponding stimulation techniques (primarily hydraulic fracturing). Thus, water sources normally used for these developments (conventional reservoirs) are the same as those used during the early stages of exploration and subsequent development of unconventional reservoirs. Some particularities in terms of type of water have been observed in such exploration shale wells. In the Los Molles formation, a mixture of fresh water (85%) and produced water (15%) was used because of the large volume of water necessary for the stimulation of a horizontal well with 10 fracture stages. For the completion in the D-129 formation, it was decided to use 100% produced water (low salinity < 10000 TDS) to conduct all of the stimulations (five fracture stages).

In each of the hydrocarbon producing basins in Argentina are unconventional resources; the primary activity of development of these reservoirs is in Neuquén Basin. Hence, the focus on this paper is on this basin. A geographical segmentation was performed in three major areas (east-blue, south-green and west-red), defining the Los Barreales dam as the midpoint reference (**Fig. 1B**). A variety of fields according to their location in the basin have tight and shale reservoirs in the vertical section of a well, leading to the development of multitarget well completions. The development of conventional reservoirs has facilitated the use of surface facilities concerning the logistics of water.

The primary sources of water in the Neuquén Basin related to the development of conventional and unconventional sources for surface stimulation are rivers (Neuquén, flow 300 m^3/s; Limay, flow 700 m^3/s; Colorado, flow 150 m^3/s), lakes, or reservoirs (Cerro Colorado, Pellegrini), or groundwater sources, such as wells with low salinity < 5000 TDS. It is important to mention that water supply wells require a regulatory permit, and that produced water from these particular wells is not suitable for human consumption or farming.

Physical-Chemical Analysis. Table 1 presents a summary of various sources of water used during stimulation in unconventional plays. It presents the primary chemical features of these sources, which have been identified based on groups of wells, areas in the Neuquén Basin (Fig. 1B), and nature of the water source (surface or underground). Additionally, the first column presents the requirements for fresh water to be used as the base element of a fracturing fluid (according to service company standards).

Area	Water Requirements	South	South	South	West	West	West	West	West	West	East	East	East	East
Group of wells		C	C	D	D	H	H	H	H	G	G	J	S	X
Type Water		River (Limay)	River (Limay)	River (Nqn)	River (Nqn)	Well #1	Well #2	Well #3	River (Nqn)	River (Colorado)	River (Nqn)	River (Nqn)	River (Colorado)	River (Colorado)
Specific gravity (SG)		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.003
pH	6 to 8	7.71	7.44	8.11	8.03	9.14	8.73	8.71	7.63	7.82	8.38	7.91	7.77	7.56
Resistivity (ohms-cm)		59.551	17.346	3.525	1.012	3.331	2.450	2.618	31.434	5.439	12.234	37.386	0.633	0.785
Temperature (°C)	15 to 40	24.4	24.5	21.0	20.7	20.6	19.9	20.4	20.7	20.8	19.1	20.9	22.9	23.2
Carbonate (mgL)	< 600	0	0	0	0	0	7.2	14.4	0	0	0	0	0	0
Bicarbonate (mgL)	< 600	67.1	54.9	158.7	268.5	278.2	244.1	258.7	68.3	155.3	97.6	134.2	585.8	561.3
Chloride (mgL)	< 30,000	2.0	10.0	620.2	80.0	348.1	428.2	372.2	24.0	172.1	36.0	24.0	1,450.6	1,660.1
Sulfate (mgL)	< 500	7.5	155.0	50.0	85.0	475.0	650.0	625.0	12.5	255.0	36.3	32.5	1,750.0	1,750.0
Calcium (mgL)	50 to 250	1.6	48.1	34.7	83.4	8.0	1.6	0.0	19.2	147.5	32.1	28.1	1,002.0	1,202.4
Magnesium (mgL)	10 to 100	2.0	9.7	8.1	17.5	1.0	1.0	1.0	6.8	12.7	14.6	7.3	170.2	170.2
Barium (mgL)		0	0	0	0	0	0	0	0	0	0	0	0	0
Strontium (mgL)		0.02	0.02	1.3	1.2	n/a	n/a	n/a	n/a	3	1.0	0.02	10.08	11.40
Total Iron (mgL)	1 to 20	0.12	0.17	0.20	0.10	0.17	0.07	0.05	0.32	0.43	0.00	0.56	0.23	0.38
Aluminum (mgL)		0.002	0.002	0.002	0.002	0.020	0.020	0.020	0.020	0.002	0.002	0.002	0.020	0.020
Boron (mgL)	0 to 20	0.0	0.0	0.2	10.9	n/a	n/a	n/a	n/a	11	0.6	0.02	0.30	0.30
Potassium (mgL)	100 to 500	0.0	0.0	2.6	13.3	0.0	0.0	0.0	0.0	32.3	11.5	1.5	22.5	15.0
Sodium (mgL)	2,000 to 5,000	24.7	27.8	427.7	51.7	546.5	682.1	646.7	12.3	65.2	1.6	34.2	504.3	408.9
TDS (mgL)	< 50,000	105	306	1,302	599	1,657	2,014	1,918	11,603	836	230	262	5,486	5,769
TSS (mgL)	< 50	2.5	2.6	5.6	0.3	30.0	16.0	7.5	143.6	0.6	0.8	1.1	4.8	0.4

Table 1—Summary of various sources of water used during stimulation in unconventional reservoirs.

One can see that underground water sources (wells) are higher than surface sources (rivers) in terms of pH, TDS, total suspended solids (TSS), chlorides, sulphates, bicarbonates, and sodium. However, all referenced sources meet the requirements established to be used in fracturing fluids.

Types of Stimulation Treatments in Shale Plays. Fig. 2A presents average water volumes per stage (m^3) for various areas (Fig. 1B), well groups, reservoir fluid types, and type of wells in the Vaca Muerta. The types of fracturing treatments performed frequently are hybrids, meaning that initially slick water (SW) is pumped followed by a gelled fluid system (linear gel (LG), crosslinked gel (XL), or both). The type of treatment applied to each well can vary, at least partly based on the source fluid reservoir and area. Additionally, Fig. 2B presents corresponding percentages based on area of the well location, the type of system used, distribution of slickwater (SW), linear gel (LG), and crosslinked gel (XL). In general, it can be observed that the greatest values of water (m^3) by stage correspond to treatments for reservoirs of gas and wet-gas (Fig. 2A red and yellow bars), being the same type of hybrid SW-XL (vertical wells) and SW-LG-XL (horizontal wells).

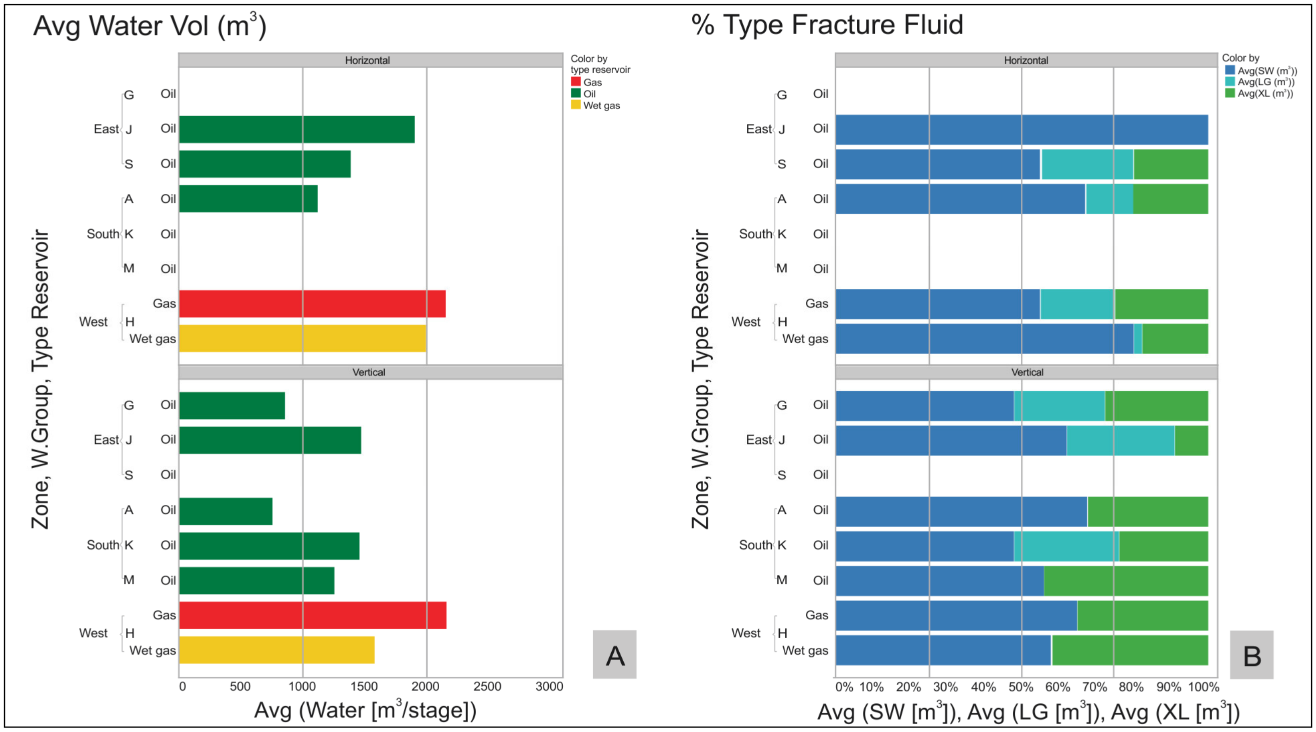

Fig. 2—(A) Average water volume per stage (m^3); (B) Percentage according to the type of fluid.

The types of treatments in Vaca Muerta have varied distribution of hybrid SW-LG-XL to SW-XL; the percentages of such systems are in the range of 45 to 80% (SW), 0 to 30% (LG), and 10 to 50% (XL) based on the carrier and the reservoir. However, there were some examples with only SW (100%). Normally, the completion of a well in the VM involves a total water volume in the order of 5500 m^3 for vertical wells and 18000 m^3 for horizontal wells.

Types of Systems for Vaca Muerta. These systems use a base fluid of fresh water and are modified by additives that serve various functions; a detail of each are presented next.

- SW: contains friction reducer, friction reducer breaker.
- LG: contains, gelling agent, buffer, and breaker.
- XL: consists of buffer, gelling agent, crosslinker, and breaker.
- In addition to these common three systems, to the base fluid is normally added biocide, clay inhibitor, and surfactant.

There are certain peculiarities by areas and group of wells, depending on how these systems are formulated.

- Group of wells (J) located in the eastern area, do not use friction reducer (SW), but rather use scale inhibitor and minimize the use of LG or XL (if necessary, they use a system of 20 ppt CMHPG with zirconate).
- Group of wells (G) located in the eastern area do not use clay inhibitor in the treatments.
- Several of the well groups for various areas use an XL 20-ppt guar-borate system fluid and the reservoir fluid and various types of surfactants (for oil reservoirs, wet gas, and gas) are often used.

Types of Treatment in Tight. Fig. 3A presents average water volumes per stage (m^3) with the same selection criteria. The treatments performed frequently (hydraulic fracturing) are hybrids or crosslinked gel, varying based on tight formation, the fluid reservoir, and the group of wells. Additionally, **Fig. 3B** presents corresponding percentages according to the type of system used, distribution of SW, LG, and XL gel. The volume of water (m^3) by stage are on average close to 300 m^3, only for Punta Rosada formation are less (150 m^3), only group D in Mulichinco have bigger volume 500 m^3. Treatments performed in Lajas and Punta Rosada formations use primarily crosslinked fluid (only the group from well G in Lajas use Hybrid), in Mulichinco it is common to use hybrid treatment designs.

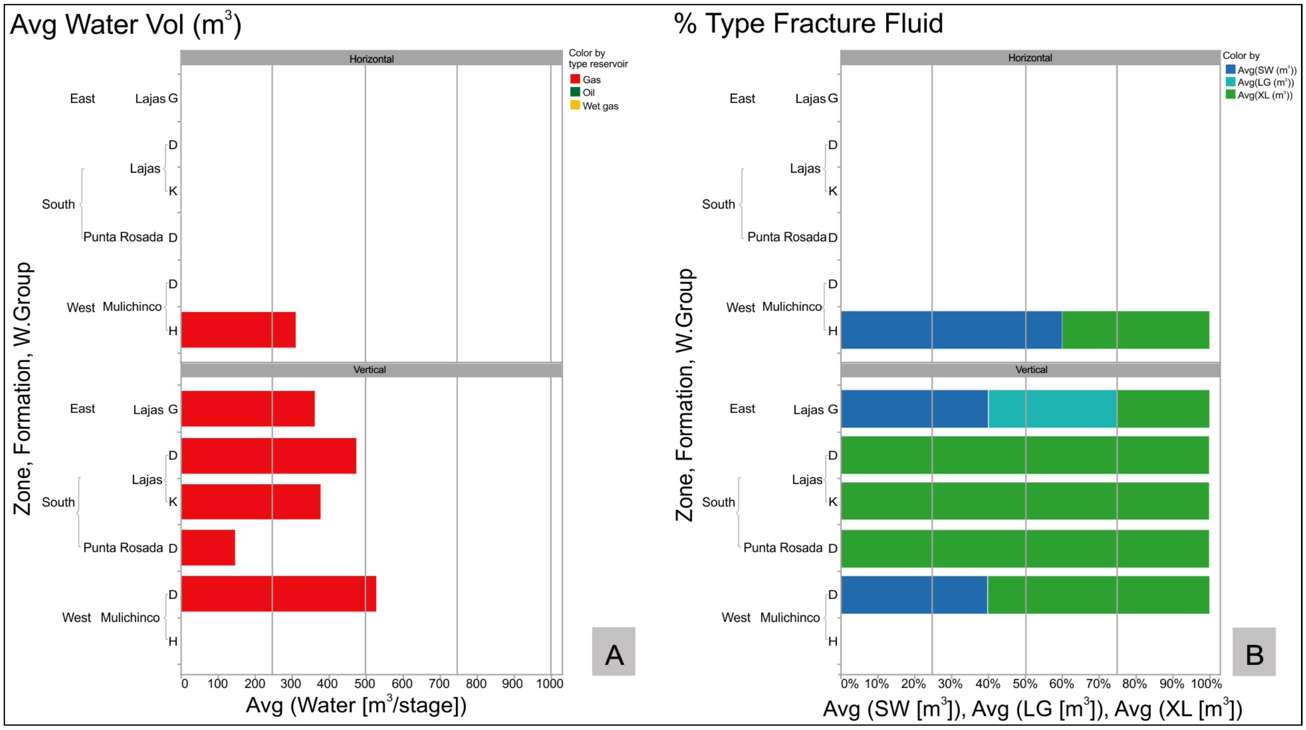

Fig. 3—(A) Average water volume per stage (m^3); (B) Percentage based on the type of fluid.

Normally, the completion of a well in the Lajas or Punta Rosada involves a total volume of water 1600 m^3 for Mulichinco in vertical wells 1800 m^3 is used and 2200 m^3 for horizontal wells.

Types of systems (SW-LG-XL) used in tight reservoirs are formulated with freshwater and are constituted by the same additives mentioned previously. There are certain peculiarities by areas and groups of wells, depending on how these systems are formulated.

- Lajas formation, all the areas use a microemulsion surfactant for gas
  - Group Wells G (eastern), use LG 10 ppt and XL fluid system guar-borate 20 ppt
  - Group Wells K (southern), use XL fluid system guar-borate 35 ppt
  - Group Wells D (southern), use XL fluid system CMHPG-zirconate 25 ppt
- Mulichinco formation for all the areas use a microemulsion surfactant for gas
  - Group Wells D have been divided primarily into Subgroups D 1 and D 2. Throughout the years, several changes in terms of treatment types, fluid systems, and average volume per stage were performed **(Table 2)**.

Subgroup D 1

Year	Fracture Type	Systems	Additional	Avg. Vol. (m^3)
2007-09	Conventional (XL)	CMHPG-zr (25 ppt)		285
2010	Hybrid (LG-XL)	guar (10 ppt) - guar-borate (20 ppt)	PrePad CO_2 (12%) of treatment vol.	375
2011	Hybrid (LG-XL)	guar (10 ppt) - guar-borate (20 ppt)		470
2012	Hybrid (SW-LG)	SW - guar (20 ppt)		350
2013-14	SW	SW		1,100

Subgroup D 2

Year	Fracture Type	Systems	Additional	Avg. Vol. (m^3)
2003-07	Conventional (XL)	HPG-borate (25 ppt)	10% Methanol in base fluid	220
2008-09	Hybrid (LG-XL)	CMHPG (10 ppt) - CMHPG-zr (20 ppt)	PrePad CO_2 (20%) of treatment vol.	425
2010-11	Hybrid (LG-XL)	guar (10 ppt) - guar-borate (20 ppt)	PrePad CO_2 (10%) of treatment vol.	550
2011-14	Hybrid (SW-XL)	SW - guar-borate (20 ppt)	PrePad CO_2 (15%) of treatment vol.	600

Table 2—Summary of various information for two subgroups of D wells, Mulichinco formation.

Yang et al. (2013), Patel et al. (2014), and Gallegos and Varela (2014) present a detailed analysis of the evolution and trends of the types of treatments for fracturing, fracturing fluids, water consumption, additives, and proppant for various basins in the United States (US), which can be evaluated comparatively with the information presented in this publication for various plays in Argentina.

Logistics

Hydraulic fractures are central to the completion of unconventional reservoirs and require large volumes of water and extensive logistics. King (2014) presents valuable information for recycling water, handling, preparation, and storage options gained in the US within the last 60 years. Tipton (2014) shows water management for operations in Granite Wash, Woodford shale, and Cana Woodford.

In Argentina, throughout the past ten years, there has been progress and development in terms of the logistics of water management for performing fracturing operations in the unconventional plays. Recently, a variety of storage systems and water movement has been observed primarily in the Neuquén basin associated with these operations. In general, storage systems have been primarily used [e.g., mobile fracture tanks (80 m^3), circular tanks (1000 to 5500 m^3), and lined pits (up to 35000 m^3)]. The movement of water has been performed primarily by trucks, and some operators have developed transfer systems using piping (aluminum tubing or pipe) and centrifugal pumps. In the Cuyo and GSJ Basins, the storage model used involved fracture tanks and water movement performed by trucks, and exploratory wells or an operator with a small number of wells. Bonapace et al. (2015) presents detailed information about various models of water management for shale reservoirs, Forni et al. (2015) document field experiences about water management in Vaca Muerta completion wells.

Tight Gas: GSJ Basin. This stimulation application started in the D-129 formation (tight reservoir) within the last three years. All operations have been performed using fracture tanks **(Fig. 4A)**. Normally, two to three fracturing stages were completed per well, consuming in average 425 m^3 of water per stage. Normally used were infrastructures, sources of water (freshwater), and water landings or platforms for the conventional reservoir in the area. The operator is in charge of moving water by truck and designs the water management process.

Tight Gas: Neuquén Basin. The primary history in this type of reservoir derives from this basin; current activity is focused along the three zones (Fig. 1B) in Lajas, Punta Rosada, and Mulichinco Formations. The first stimulation treatments performed during the exploration and development phase in these formations used mobile fracture tanks **(Figs. 4B and 4C)**. More recently, in the Mulichinco formation the circular tanks (2000 m^3) are beginning to be used because of the large water volume necessary to perform SW treatments (**Fig. 4D**). In general, the three zones (Fig. 1B) have a good infrastructure in the area and sources of water (Neuquén river) also have water landings or platforms. The water management service is normally performed by a third-party company (provision of circular tanks) and the operators are in charge of water movement by the trucks.

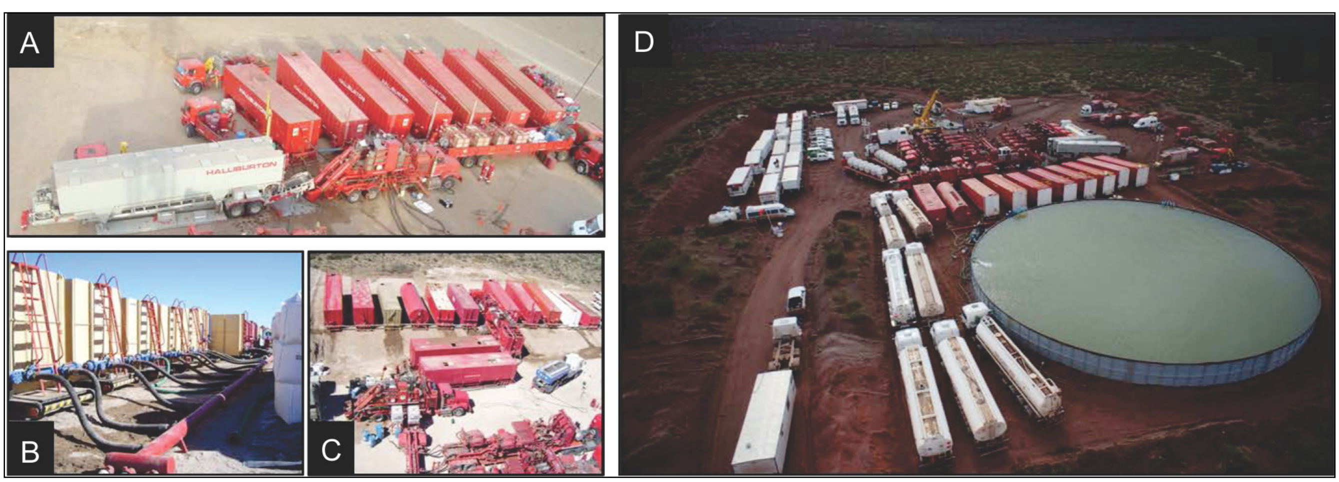

Fig. 4—Tight operations (A) D-129 Formation, fracture tank (550 m^3); (B,C) Lajas Formation, fracture tank (850 m^3); (D) Mulichinco Formation, circular tank (2000 m^3).

Shale: Neuquen Basin. During the last three years, a rapid development for water logistics was achieved primarily in shale reservoirs. The most recent activity was in Vaca Muerta with horizontal wells, which required great amounts of water (20000 m^3) based on the large number of fractures (10 to 15 stages). **Fig. 5** illustrates an example.

Single Horizontal Well. In this case, a water location was prepared **(Fig. 5A)** with a capacity of 16000 m^3 (eight circular tanks), located 2 km from the horizontal wellsite with a positive difference of 70 m ground level. The circular tanks were filled by truck and the water sources were water wells and the Colorado River. The transfer from water location to wellsite was performed by centrifugal pumps and 8-in. aluminum pipes. At the horizontal wellsite **(Fig. 5B),** there was a total storage capacity of 5500 m^3 (circular and fracture tanks); transfer from the circular to the fracture tank was performed by centrifugal pumps.

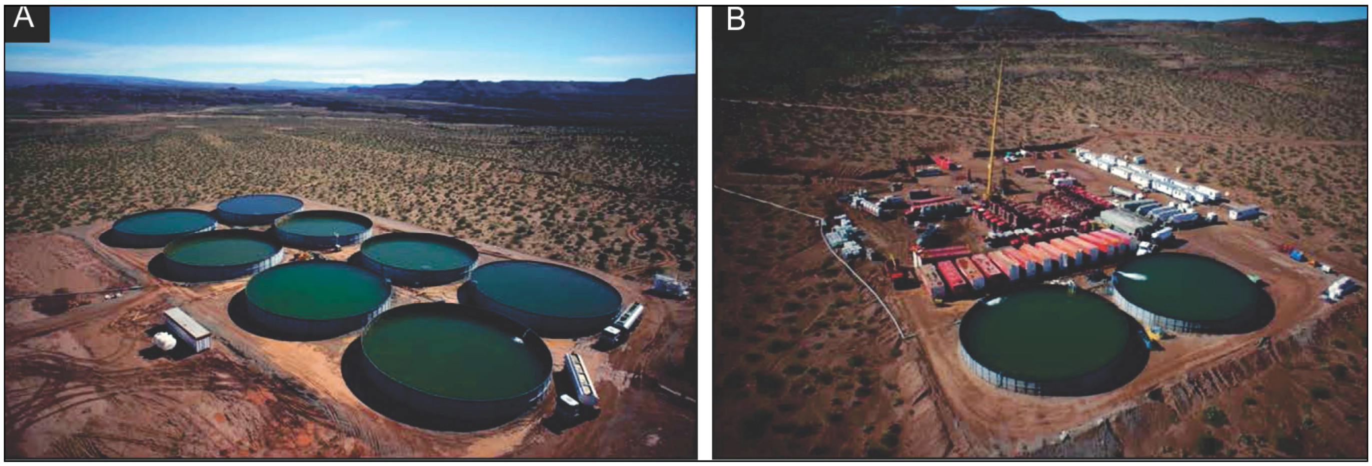

Fig. 5 — (A) Water location, circular tanks (16000 m^3); (B) Horizontal well pad location, circular and fracture tanks (5500 m^3).

Multi-horizontal Well Pad. A detailed water management plan was prepared in this case involving a well pad with three horizontal wells (a total of 33 fracture stages) and is shown in drawing form at the top of **Fig. 6.**, These were programed for simultaneous well operations. A total of 11 days were estimated for completion of all stimulation operations on the three wells on the pad and it was estimated to consume approximately 60000 m^3 of water supply. For this project, the source of water used was groundwater (well water with low salinity, but not potable water) because of the long distances to other water sources (rivers). A new Water Well 2 (WW 2) was drilled close to the central water storage (CWS); this well had a flow capacity of 1000 m^3/D, an existing WW 1 had a flow capacity of 1300 m^3/d, providing a total daily water volume of 2300 m^3.

The primary system was formed by a CWS, located 25 m from WW 2 and had the capacity to store 16000 m^3 (8 circular tanks) having booster pumps and 8-in. aluminum pipe to move water from CWS to the pad location. The alternative system was formed by WW 1, with 4 1/2-in. tubing and two water storage units, A and B, with a total capacity of 18000 m^3 (nine circular tanks) having a booster pump and 8-in. aluminum pipe to transfer water from water storage unit A to the pad location.

To begin the 3-well stimulation part of the completion plan, all the water storage systems were filled. The primary systems are shown in **Fig. 6A** (16000 m^3), and the alternative systems are illustrated in **Fig. 6C**, (18000 m^3). The PAD location of the three wellheads is pictured in **Fig. 6B** (5500 m^3), showing a total water volume of 39500 m^3 was available. During the completion, it was refilled to provide another total volume of 25300 m^3 to complete all the water necessary for the operation plan.

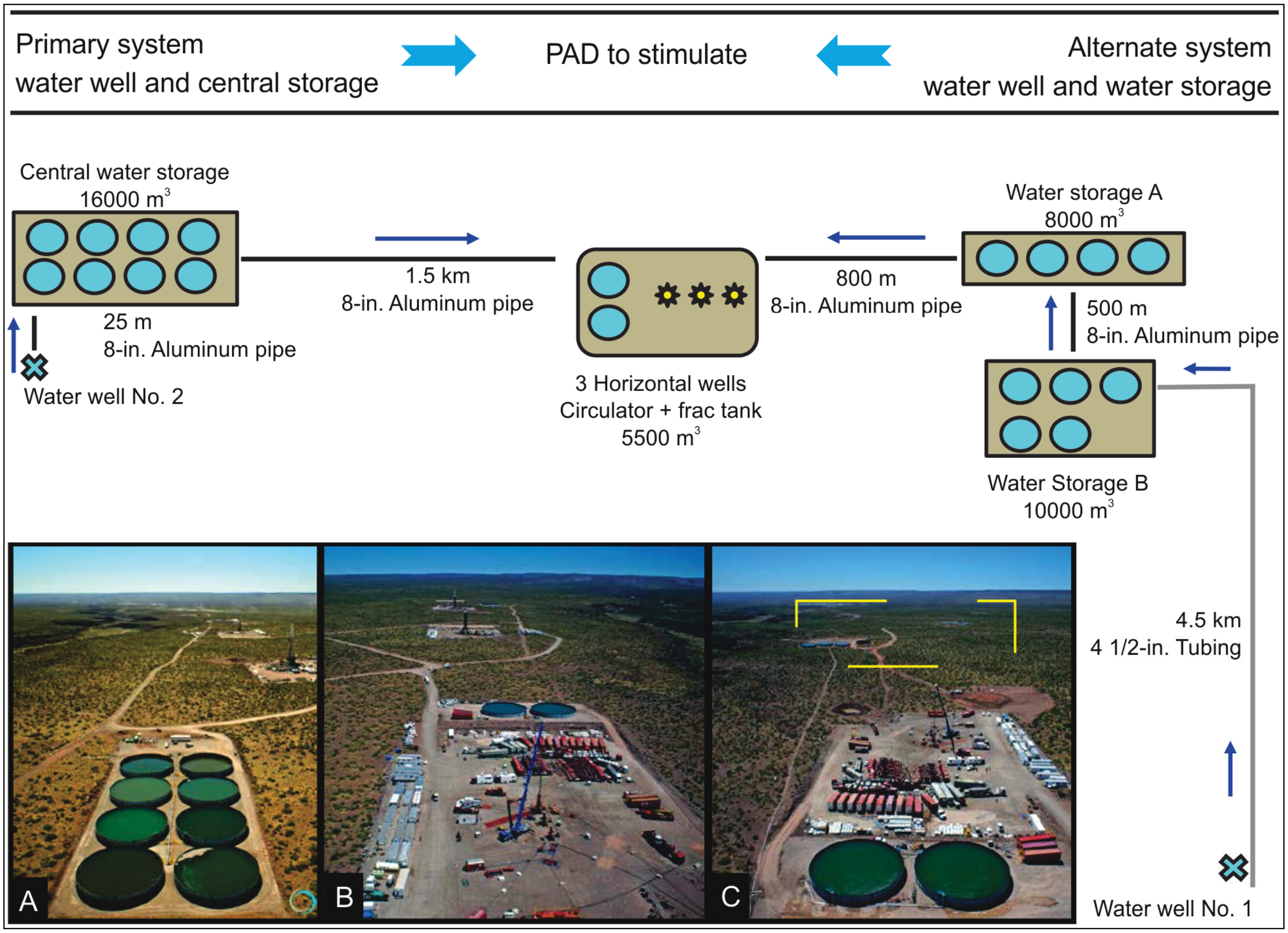

Fig. 6—Water management plan for Well-PAD: (A) Photo of central storage water that is shown upper left in drawing; (B) PAD location of the 3 horizontal wellheads; (C) alternative storage system that is at right in upper drawing is shown in distance at top of this photo inside the yellow box.

Use and Reuse of Flowback, Produced, and Treated Water

In this section, the possibility of using water nontraditionally (flowback, produced), either treated or untreated, is analyzed. A group of laboratory studies were conducted to evaluate various alternatives for the use of these nontraditional waters as a basic element of fracturing fluid, primarily for use in a crosslinked gel system. The tests performed were as follows:

- Detailed water (physical-chemical) analysis.
- Potential inhibition for clays.
- Damage by insoluble precipitates, generated from modification of the pH of these waters.
- Fluid test (new fracture fluid) for various bottomhole conditions with several types of water.

Physical-Chemical Analysis. Table 3 presents a summary of various flowback and produced water detailed by a group of wells, subgroup, and reservoirs in the Neuquén Basin. The same can be seen in the primary physico-chemical variables of these waters. All the samples referred to as shale corresponds to Vaca Muerta; for tight reservoirs, Subgroup D 1 and D 2 were from the Mulichinco, and D 3 was from the Punta Rosada formation.

Type Water	Flowback and Produced Water														
Area	West	South	South	South	South	South	East	West	West	West	West	West	West	West	West
Group of wells	D	D	D	D	A	C	G	H	H	H	H	H	H	H	H
Sub-group	D#1a	D#2a	D#3a	D#3b	A#1a	C#1a	G#1a	H#7a	H#1a	H#2a	H#3a	H#4a	H#5a	H#6a	H#2b
Reservoir	Tight	Tight	Tight	Tight	Shale	Shale	Shale	Shale	Shale	Shale	Shale	Shale	Shale	Shale	Shale
Type water	FB	FB	FB	FB	PROD	FB	PROD	PROD	FB	FB	FB	FB	FB	FB	FB
Specific gravity	1.042	1.018	1.060	1.060	1.130	1.045	1.065	1.136	1.074	1.123	1.143	1.123	1.156	1.099	1.110
pH	6.38	6.69	6.00	5.98	5.62	6.35	5.74	6.48	6.74	5.06	5.25	4.65	4.82	5.59	4.50
Resistivity (ohms-cm)	0.109	0.176	0.026	0.024	n/a	0.082	0.074	0.026	0.067	0.030	0.023	0.024	0.035	0.049	0.040
Temperature (℃)	21.1	21.2	21.6	21.6	n/a	20.8	21.2	20.2	26.0	23.0	24.0	24.0	20.7	20.5	20.8
Carbonate (mgL)	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0
Bicarbonate (mgL)	353.9	2,257.7	109.8	85.4	257.3	610.2	195.3	146.4	1,196.0	131.8	107.4	0.0	61.0	329.5	61.0
Chloride (mgL)	30,011.9	15,005.9	118,546.8	126,049.8	86,837.6	37,014.8	58,022.9	118,546.8	67,026.5	106,041.9	131,051.8	135,051.8	148,058.5	87,034.4	92,536.5
Sulfate (mgL)	370.0	420.0	40.0	35.0	0.0	0.0	235.0	0.0	10.0	262.5	137.5	100.0	0.0	233.3	265.0
Calcium (mgL)	3,206.4	1,402.8	13,306.6	15,711.4	15,967.9	6,012.0	15,230.4	21,643.0	7,134.2	23,406.7	17,955.8	30,781.4	35,671.2	18,036.0	27,655.2
Magnesium (mgL)	1,264.6	413.4	1,459.2	1,167.4	4,902.9	1,264.6	729.6	2,140.2	1,702.4	3,988.5	2,723.8	4,669.4	2,432.0	2,918.4	1,216.0
Barium (mgL)	0	0	0	0	725	100	0	800	800	0	0	0	1,275	2.5	0
Strontium (mgL)	270.0	0.3	948.0	840.0	n/a	n/a	702.0	2,078.0	n/a	2,120.0	4,210.0	3,170.0	2,900.0	385.0	1,000.0
Total Iron (mgL)	118.50	194.00	26.50	21.75	38.00	56.25	21.50	21.25	575.00	243.75	6.50	150.00	68.00	98.00	196.25
Aluminum (mgL)	0.002	0.002	0.020	0.020	n/a	0.050	0.020	0.020	0.020	0.020	0.020	0.020	0.002	0.020	0.002
Boron (mgL)	7.8	2.0	10.2	8.4	n/a	7.7	21.3	29.8	24.2	10.4	17.2	24.2	15.5	29.2	12.6
Potassium (mgL)	535.0	0.0	1,015.0	1,028.8	2,150.5	0.0	750.0	2,750.0	250.0	998.0	2,130.0	1,700.0	2,905.0	504.0	1,250.0
Sodium (mgL)	13,149.7	8,381.8	57,821.5	60,450.3	27,250.3	14,590.7	18,178.5	45,234.5	32,225.5	34,489.0	59,261.3	40,819.0	47,526.9	29,913.7	24,832.7
TDS (mgL)	49,010	28,076	192,325	204,550	138,129	58,187	93,363	190,562	110,920	171,682	217,584	212,982	237,998	139,070	149,713
TSS (mgL)	569.2	27.7	84.0	119.0	n/a	666.0	356.5	714.5	163.0	310.4	235.6	240.0	120.0	517.2	194.0

Table 3—Summary of data for flowback and produced water in various fields in the Neuquen basin.

These types of water (flowback and produced) have quite similar characteristics, which vary from fresh water. In general, such waters have high values of SG, low pH values (being slightly acidic), high levels of TDS, TSS, and significant values of calcium, magnesium, sodium, potassium, iron, boron, barium, and strontium.

In general, differences between Mulichinco, Punta Rosada, and Vaca Muerta flowback-produced water are significant. If the waters for these three formations are compared, it shows that waters in Mulichinco have the lowest values of TDS, Ca, boron, and strontium. Punta Rosada presents the lowest values for iron, intermediate for calcium, magnesium, strontium, and the same level of TDS as the Vaca Muerta. For this last formation, the lowest values of pH and the highest level of calcium, magnesium, strontium, and iron were observed.

Olsen et al. (2013) presents values of the composition of flowback waters of the some North American sources of rock plays, which can be evaluated comparatively with the information shown in Table 3.

Moreover, **Table 4** shows the physical and chemical results for five samples of flowback and produced water, which have been treated by four various service companies (water treatment). The types of treatments performed by these various companies were Treatment Methods I, II, and III corresponding to treatments of chemical coagulation, flocculation, and separation; the IV Treatment Method consisted of electro coagulation, pH adjustment, separation weir tank, and multimedia filter. The last sample (T-H#4b), was only filtered.

Water Type	Treated Water					
Area	West	East	East	West	West	West
Group of wells	H	J	S	H	H	H
Subgroup	T-H#1a	T-J#1a	T-S#1a	T-H#2c	T-H#7a	T-H#4b
Reservoir	Shale	Shale	Shale	Shale	Shale	Shale
Type water	FB	FB	FB	FB	PRO	FB
Treated method	I	II	II	III	IV	*filtered*
Specific gravity	1.060	1.094	1.160	1.070	1.125	1.060
pH	7.84	5.87	8.00	7.32	9.12	6.38
Resistivity (ohms-cm)	0.075	0.049	0.028	0.047	n/a	0.046
Temperature (℃)	19.5	21.1	21.9	18.1	n/a	21.8
Carbonate (mgL)	0	0	36	0	66.5	0.0
Bicarbonate (mgL)	219.7	170.9	1,073.9	244.1	0.0	268.5
Chloride (mgL)	59,523.5	85,033.6	121,548.0	61,524.3	104,687.0	67,526.7
Sulfate (mgL)	0.0	325.0	130.0	6,375.0	5.0	80.0
Calcium (mgL)	6,332.6	14,909.8	28,216.3	3,206.4	155.0	16,354.6
Magnesium (mgL)	729.0	1,167.4	155.7	1,945.6	857.0	1,264.6
Barium (mgL)	110	0	0	0	874	0
Strontium (mgL)	1,400.0	1,080.00	7,550.00	177.00	1,846.0	2,960.0
Total iron (mgL)	0.45	11.00	5.50	2.60	1.32	18.25
Aluminum (mgL)	0.020	0.002	0.020	0.002	0.920	0.020
Boron (mgL)	12.0	13.7	1.5	8.2	22.8	63.0
Potassium (mgL)	16.0	1,945.0	4,390.0	253.1	2,066.0	1,497.5
Sodium (mgL)	29,984.4	34,054.7	46,580.6	35,389.8	47,182.0	21,242.7
TDS (mgL)	96,916	137,617	197,746	108,940	172,097	108,251
TSS (mgL)	4.4	34.6	16.0	4.3	10.1	98.0

Table 4—Physical and chemical results for four samples of flowback and produced water.

These treated waters generally have values of the same order of flowback-produced waters; if significantly different, it is important to observe certain indicators that have varied amongst the treatments performed. In general, because these waters contain present pH values ranging from slightly acidic to neutral, to slightly alkaline, reduction in the amount of iron and TSS is clearly visible, while the content of TDS and salts remain high. The sample T-H#4b was filtered and is only possible to evaluate based on the TSS content; clearly, values are highest compared to other waters treated.

For a better understanding of the action of the treatments applied to these waters, one can compare the results of the samples corresponding to groups of Well H (Subgroup H 1, H 2, and H 7 to Tables 3 and 4).

Action as Clay Inhibitor. During the stimulations performed in the unconventional plays in Argentina, the following types of clay stabilizer have been used:

- Quaternary ammonium salt (liquid).
- Inorganic salt—KCL (solid) (Garcia et al. 2013).
- New ultralow-molecular-weight cationic organic polymer (liquid) recently applied to replace the first (Weaver et al. 2011; Bonapace et al. 2015).

The goal of this section is to evaluate produced water in relation to their power of inhibition on formation clays (cuttings). High salt content (TDS) makes it very unlikely to use certain additives (clay stabilizer). Capillary suction time (CST) testing was performed to help determine this. More detail involving its methodology can be found in Ramurthy et al. (2011).

Below, results of tests conducted for various shale and tight formations are presented; the main idea was to identify the degree of sensitivity compared to a nontraditional source of water.

Shale Play Formations. It was decided to evaluate the Cacheuta, Los Molles, and Vaca Muerta formations. For these formations, the following waters were used (**Table 5**):

- DI + clay inhibitor (**Fig. 7A**, yellow bars).
- Produced water (untreated) Fig. 7A, green bars.

Type	Group Wells	Subgrup	Percentage (%)	TDS (mg/L)	Clay Stabilizer (gpt)
DI	—	—	100	0	1.4
Produced	H	H#7a.	100	190,562	No
*Clay stabilizer = quaternary ammonium salt					

Table 5—Water evaluated in tight and shale formation .

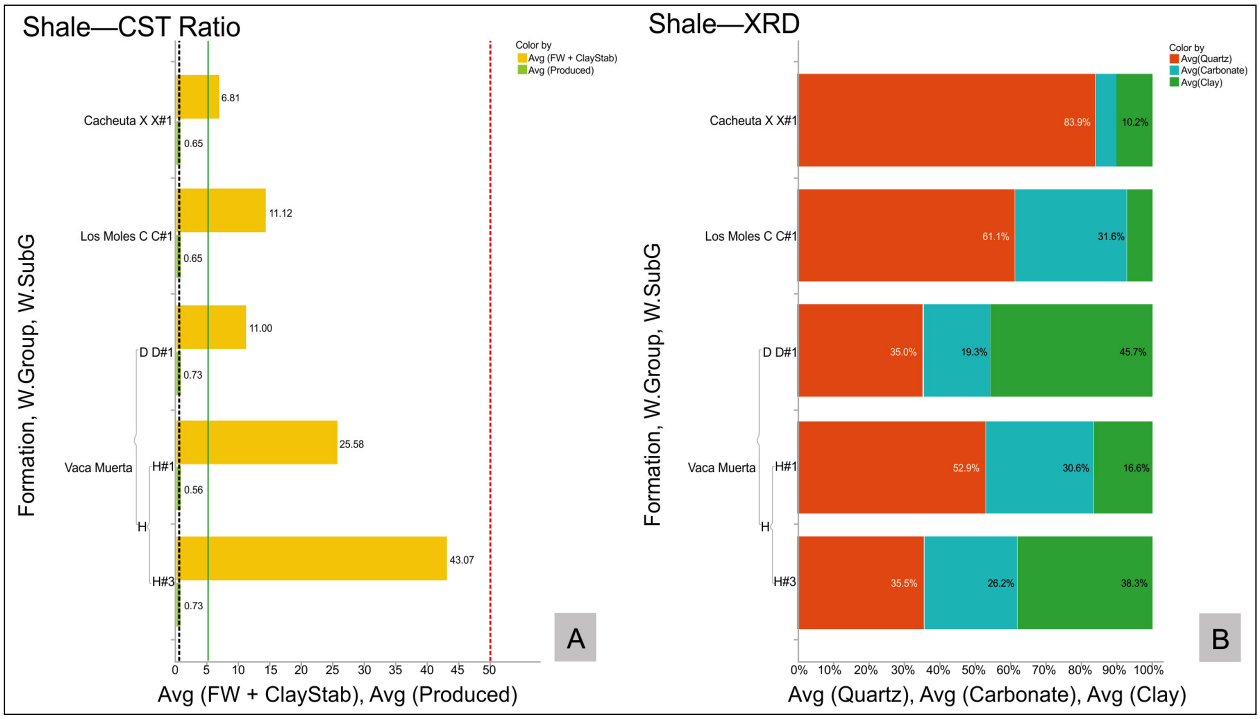

Fig. 7—(A) CST for various shale in Argentina; (B) mineralogy for each shale.

In Fig. 7A, test results are presented based on various shale plays, groups of wells, and subgroups for the VM. Two further lines are referenced, which indicate the degree of sensitivity (no sensitive CST ratio = 0.5 dotted line black and extremely sensitive CST ratio = 50 red dotted line). For reference, a green solid line has been placed for the CST ratio = 5, which is considered an acceptable value for the Vaca Muerta formation because it is the one with a greater sensitivity. There is a clear correspondence to the high values of CST ratio (Fig. 7A, yellow bars) and the percentage of clay (**Fig. 7B**, green bars) for the Vaca Muerta.

In general, a higher degree of sensitivity is observed in the aqueous phase to the Vaca Muerta, unlike the Cacheuta and Los Molles (Fig. 7A, yellow bars); this reflects the need to increase the dosage of inhibitor or change the same, Bonapace et al. (2015) presents test results for various types of clay stabilizers for six fields in Vaca Muerta. Moreover, for all the shale analyzed, it was observed that the use of nontraditional water (Table 5, high TDS produced water) has a superior inhibition that does not require adding a clay stabilizer (all the values are below to 0.5 that reflects as not sensitive, Fig. 7A green bars).

Additionally, Bonapace et al. (2015) documents a test performed at Vaca Muerta to evaluate various sources of water, such as mixed (flowback-fresh), produced, or flowback and flowback treated. The results obtained denoted a very good power of inhibition.

Tight Formation. It was decided to evaluate the Mulichinco, Punta Rosada, Lajas, and Potrerillo formations with the same criteria; the waters used for this test were the same (Table 5).

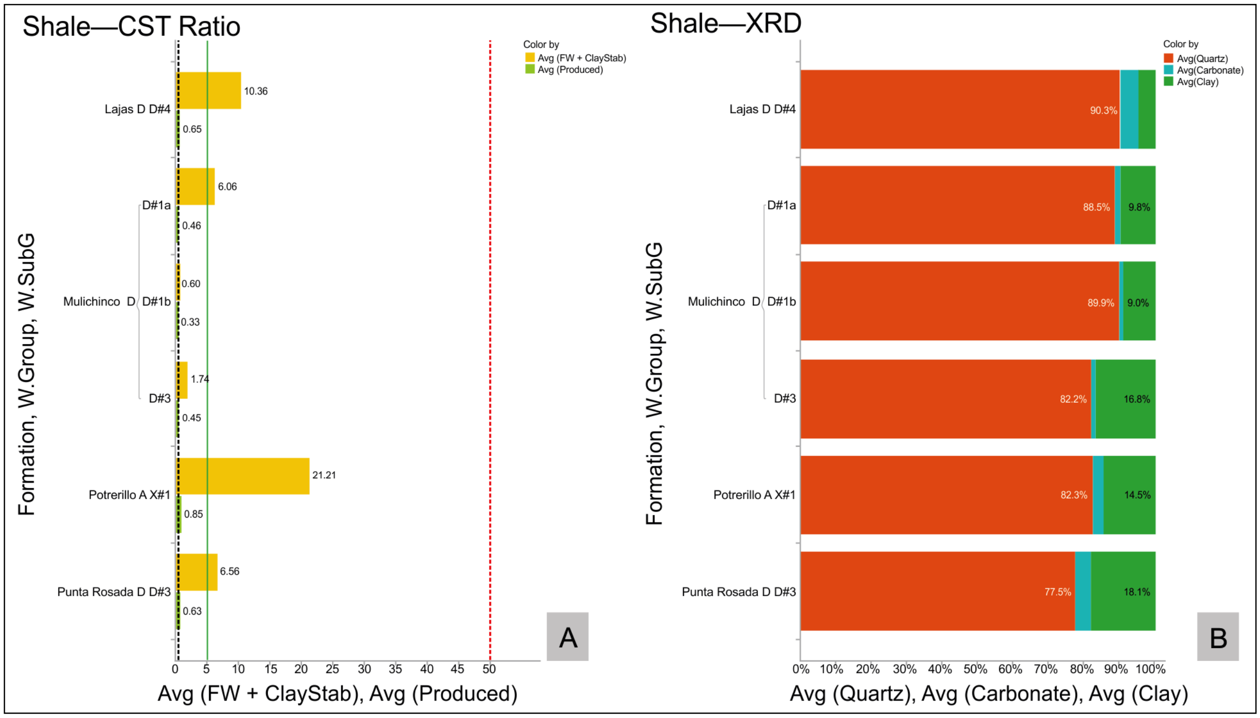

Fig. 8—(A) CST for various tight formation in Argentina; (B) mineralogy for each tight formation.

A lower degree of sensitivity to the aqueous phase is observed in general for Mulichinco, Lajas, and Punta Rosada formations, but not for the Potrerillo formation (**Fig. 8A**, yellow bars). Moreover, for all the tight formations analyzed, it was observed that the use of nontraditional water (Table 5, high TDS produced water) has a superior power of inhibition that does not require adding a clay stabilizer (all the values are below to 0.5, which does not reflect as sensitive Fig. 8A, green bars). Clearly, these tight reservoirs have a lower percentage of clays, lower than 18% (**Fig. 8B**, green bars) reflecting those results.

In general, tight formations were least sensitive to the aqueous phase than shale formations (yellow bars for Fig.7A and Fig. 8A). Tipton (2014) documents the application of recycled water and treated water as a brine is added to the base fluid, achieving a concentration of 1% KCL (clay stabilizer) in the operations of the Woodford Shale.

Damage. Bonapace et al. (2015) presents results for the damage generated in a proppant pack for the action of high levels of TSS in nontraditional water or by gel residue, generated for a guar-borate crosslinked fluid formulated using fresh water.

It is well-known that borate and some metallic (Zr, Ti, and Al) fracture fluids work at a high pH, but there is a group of metallic fracture fluids at low pH. The objective of this test was to evaluate the potential for generating damage in packed sand by the action of floculants or insoluble components, generated in nontraditional water (high level of TDS, and calcium, magnesium ions) at various ranges of pH. In a previous work, Bonapace et al. (2015), presents a clear example of this precipitation when nontraditional water was used to prepare a borate fracture fluid (usually works at a high pH). Several authors documented this situation, which can negatively impact a proppant pack (Monreal et al. 2014; Haghsgenas and Nasr-El-Din 2014; Fedorov et al. 2014).

These tests were selected for three water samples **(Table 6)** with various levels of TDS and calcium, magnesium ions and were proceeded to complete the following steps:

- Each sample was filtered through five micron filters with a vacuum pump, in an attempt to reduce the amount of TSS; after that, a new value of TSS was determined (Table 6 and **Fig. 9A**, left columns unfiltered, right filtered).
- Then, each sample was divided in two equal volumes, one volume was raised to a pH of up to 10.5 using sodium hydroxide, and the other volume was adjusted to the pH of up to 5.5 with acetic acid (for sample C, nothing was necessary to adjust the pH with acetic acid because of the low pH of this water).
- The samples were evaluated visually. Flocs and insoluble precipitates were observed in all high pH samples (**Fig. 9B**, left columns high pH, and right low pH).

Sample Water Type	Subgroup Wells	TDS (mg/L)	Ca (mg/L)	Mg (mg/L)	TSS (mg/L)	Filtered TSS (mg/L)
A - FB	D#2a	28,076	1,402	413	27.7	18.2
B - FB	D#3a	192,325	13,306	1,459	84.0	36.7
C - FB	H#4a	212,982	30,781	4,669	240.0	25.6

Table 6—Water evaluated for damage in sandpack.

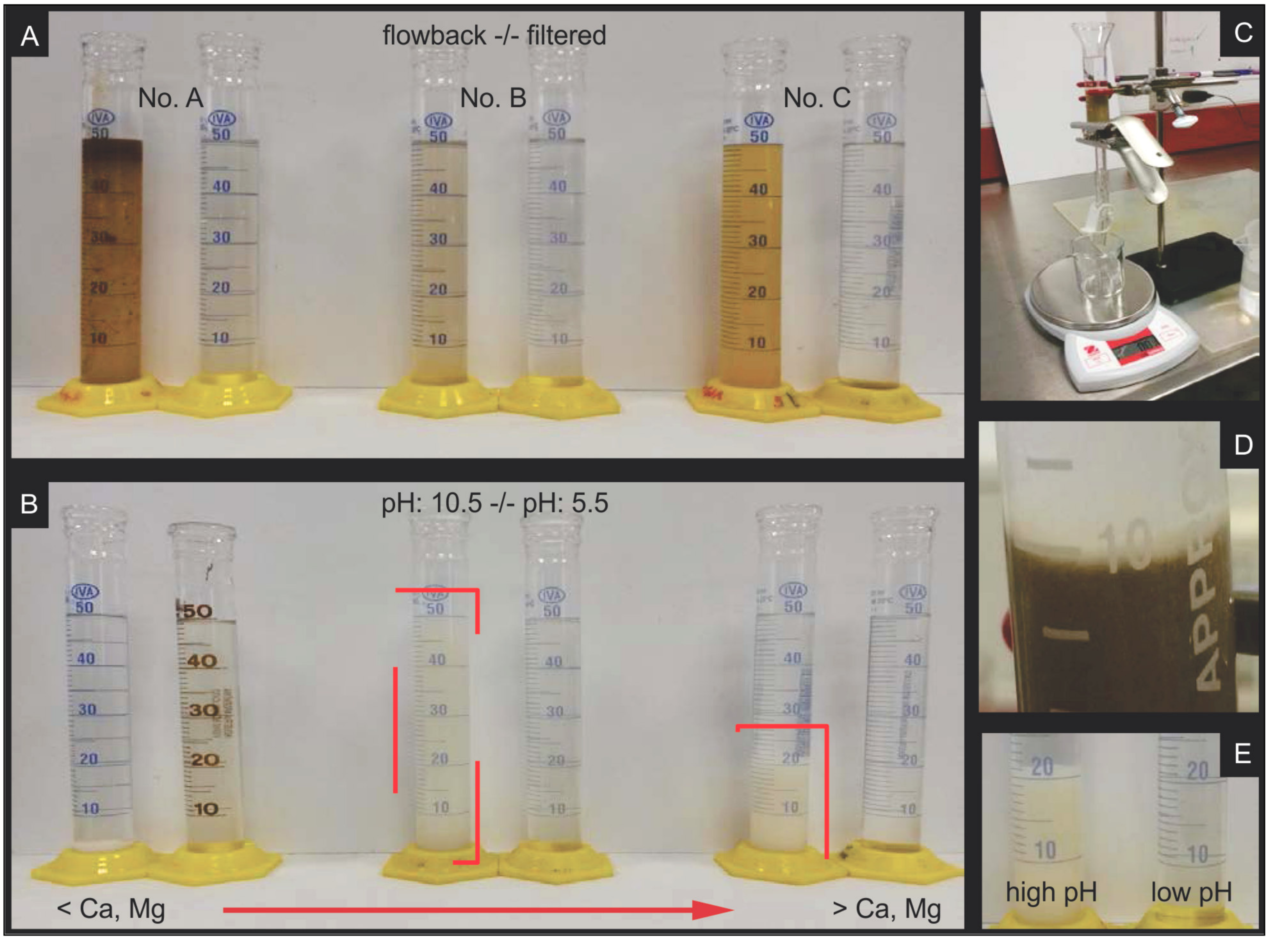

Fig. 9 — Test chemical damage. (A) flowback water filtered; (B) flowback water filtered with high and low pH; (C) fluid recovery test; (D) insoluble component deposited over the sandpack; (E) detail of sample #C.

The second part of the study was completed with a fluid recovery test **(Fig. 9C)**, which consists of preparing a test column with 70/140-mesh pack (i.e., commonly 100 mesh), determining pore volume, passing three volumes initially, and then proceeding to spend the various samples filtered (high and low pH) to be tested for a time period of 10 minutes. Then, the percentage of displaced fluid right through this pack for the testing time is determined. In high pH samples, precipitations, floculants, and some degree of turbidity in the samples was observed when the final pH was achieved. During the flow recovery test, it was identified that insoluble components deposited over the sandpack **(Fig. 9D)** were plugging it. A significant increase in insoluble components was detected with increasing Ca and Mg ion content for various samples (Fig. 9B, left columns indicated, sample #C with more detail in **Fig. 9E**), at high pH. Low pH generations of floculants and insoluble components were not observed for all samples (Fig. 9B, right columns).

The final results for this test showed two primary observations; first, a greater displaced fluid volume was obtained for all the samples at a low pH **(Fig. 10A)**; close values for low pH samples were achieved as deionized water (blue light line, **Fig. 10A**), indicating nondamage in the sandpack. Second, an important reduction in the displaced fluid volume was identified for all of the samples at a high pH **(Fig. 10B)**. This shows the effects of flocs and insoluble components, clogging, and damaging the sandpack.

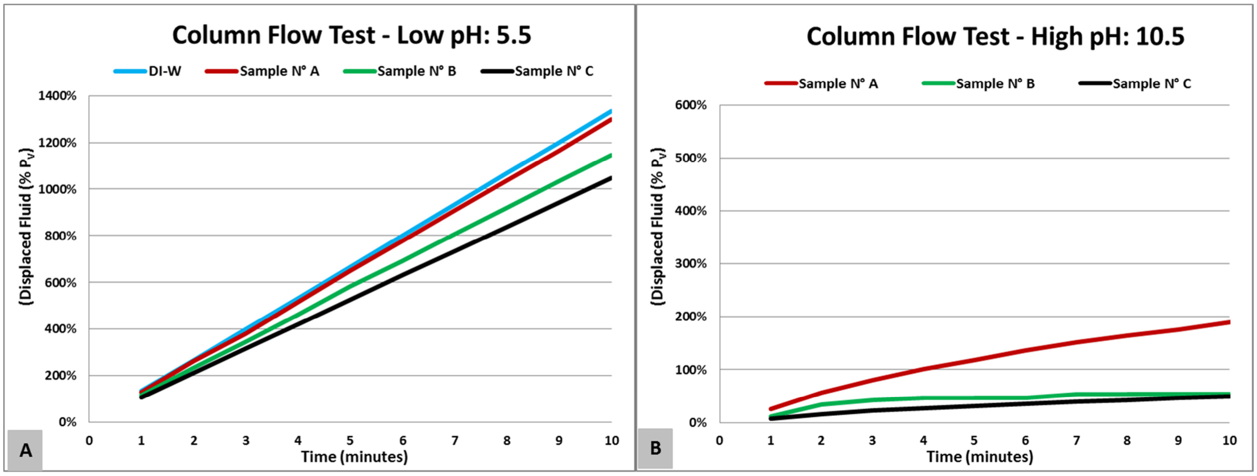

Fig. 10—Column flow test. (A) Flowback water filtered at low pH; (B) flowback water filtered at high pH.

Fig. 11 presents the value at the end of the test in bars (final time = 10 minutes); refer to the left axis. For high pH solutions, the increasing reduction with reference to DI water (red dots, refer to right axis) was markedly observed, achieving 96% for sample C; this increment has a direct relation to the amount of calcium and magnesium present in these waters (Table 6). At low pH solutions, this effect was not observed and the value of percentage reduction was related more to the amount of TSS remaining after the filtration process. In general, it was observed that there was minimal impact in the sandpack for chemical precipitations.

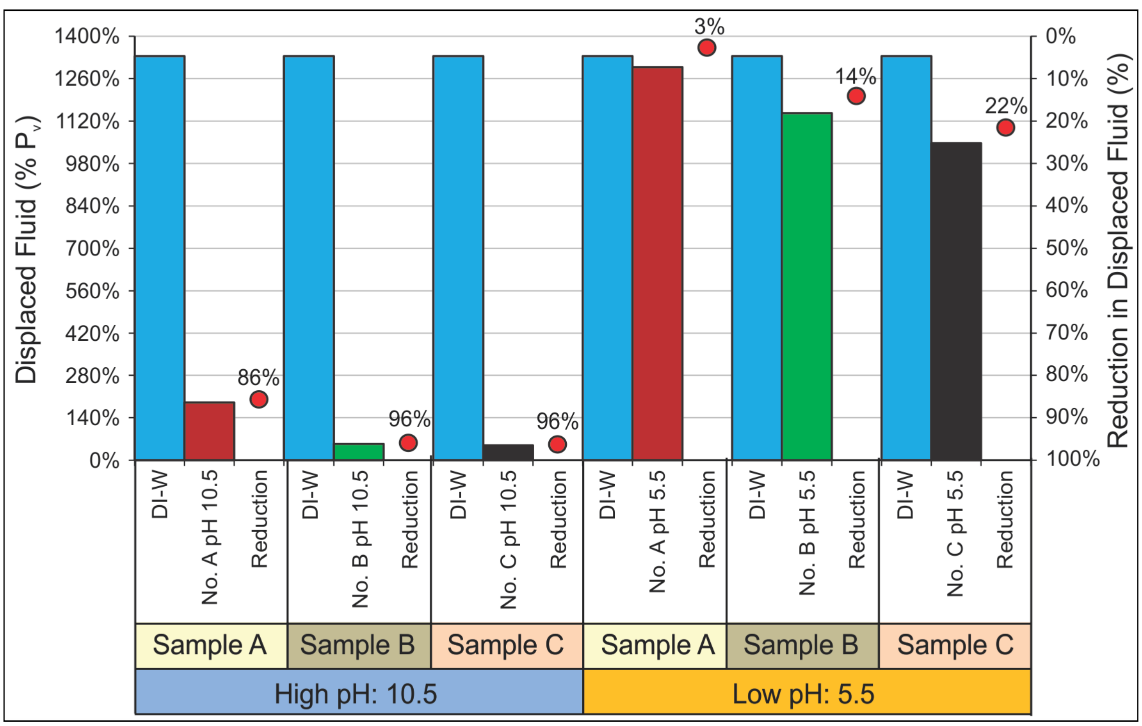

Fig. 11—Values post-testing to compare high and low pH.

Fracturing Fluid: Recently, there have been studies on the development of fracturing fluids using flowback or produced water (treated or untreated) with high TDS values. A summary of several publications are presented next.

Laboratory Studies. Haghsgenas and Nasr El Din (2014) presents a group of laboratory studies that show the adverse effects of some ions present in flowback water from the west Texas region in a guar-borate fracture fluid. This work recommends the acceptable levels for ions (calcium and sodium) to achieve good performance for this type of fracture fluid.

Additional Component Added to Nontraditional Waters to Improve the Performance of Fracture Fluid. Li et al. (2009) developed a new fluid stabilizer to protect the polysaccharide fluid from damage by bacterial enzymes in produced water. This fluid stabilizer not only mitigated the damaging effect of bacteria, but also denatured other sources of enzymes present in flowback water. This fluid stabilizer is added into the produced water before the hydration process. It was used in fracturing treatments to prepare a guar-borate crosslinked fluid system in Elk Hills, California. Li et al. (2010) documents the use of this fluid stabilizer for guar-titanate crosslinked fluid systems in New Mexico. Fedorov et al. (2014) presents a scale inhibitor, which prevents scale deposition by sequestering the cationic scale-forming ions and distorting the crystalline lattice structure, has good thermal stability, and very effective ion stabilization. This scale inhibitor was used with various blends of produced water and guar-borate crosslinked fluid systems in the Delaware Basin.

Nontraditional Waters, Treated. LeBas et al. (2013) documents the application of CMHPG-Zr fracture fluid in New Mexico using produced water with more than 270,000 mg/L TDS. Monreal et al. (2014) developed a new fluid system (alternative viscosifying polymer system) more cost-effective than the CMHPG-Zr. It was tested up to 250°F and with 110,000 mg/L TDS waters. For both authors, the water used previously was treated using an electrocoagulation process.

Nontraditional Waters, Not Treated. Huang et al. (2005) documents the laboratory studies and field application in New Mexico. The fracturing fluid system employed was a 70 Qualty CO_2 foamed with CMHPG-Zr crosslinked fluid using produced water with levels of 23,000 mg/l TDS. Bonapace et al. (2012) documents the application of guar-borate fracture fluid using produced water (low salinity) in Argentina. Kakadjian et al. (2013) documents the application of CMHPG-Zr fracture fluid using produced water from Bakken with a level of more than 220,000 mg/L TDS where there were 52 fracture stages completed in two wells. Legemanh et al. (2013) presents results for laboratory studies of CMHEC-Zr crosslinked fluid using produced water with 200,000 mg/L TDS and 40,000 mg/L hardness. Li et al. (2014) documents laboratory tests for an organometallic-crosslinked derivatized plysaccharide fluid formulated with produced water with 330,000 mg/L TDS, and 90,000 mg/L hardness with good results.

In a recent publication, Bonapace et al. (2015) presents a new fracture fluid developed and tested at a laboratory using flowback water form Vaca Muerta wells. A blend of water (50% flowback not filtered, not treated + 50% fresh water) was used and 100% of treated flowback water used in another application. In this publication, the goal was to evaluate this new fracture fluid for two various conditions for tight reservoir and using 100% of flowback water only filtered without any kind of treatment. The general conditions were these:

Deeper wells:

- Formation—Lajas and Punta Rosada.
- Depth—3400 to 3900 m.
- Type of fracture treatment—100% XL fluid, correspond to Well Group D, located at southern zone (Fig. 3A).
- BHT average was 220°F.
- Slurry fracture rate average was 20 to 35 bbl/min.
- Pumping time average was 30 to 50 minutes.

Intermediate depth wells:

- Formation—Mulichinco.
- Depth—1550 to 1800 m.
- Type of fracture treatment—Hybrid, correspond to Well Group D and H, located at the western zone (Fig. 3A).
- BHT average of 150°F.
- Slurry fracture rate average of 40 to 60 bbl/min.
- Pumping time average of 45 to 65 minutes.

Rheology Test. Initially performed was a stability test to evaluate the proper response of the fluid with these waters and was adjusted to various gels loading. After that was performed, a breaker test for the fluid was selected. All the tests were performed using 100% of these waters and the tests were performed using a viscometer equipped with a rotor bob, 120 minutes by simulation BHT and a constant shear stress of 40 1/s. The fracture fluid tested was the same formulation for shale flowback water treated (Bonapace et al. 2015) with slight changes in pH adjustment, concentration of crosslinker, and gelling loading **(Table 7)**. Two types of nontraditional water for these tests were used (filtered only).

Test No.	Water	TDS (mg/L)	Type Test	BHT (°F)	Gel Load (ppt)
1	South Zone—D#3a filtered	192,325	Stabilitiy	150	25
2	South Zone—D#3a filtered	192,325	Stabilitiy	150	30
3	South Zone—D#3a filtered	192,325	Break	150	25
4	West Zone—T-H#4b	108,250	Stabilitiy	220	25
5	West Zone—T-H#4b	108,250	Stabilitiy	220	30
6	West Zone—T-H#4b	108,250	Break	220	30

*For more details about water, refer to Tables 3, 4, and 6. Sample D#3a was filtered in the laboratory.

Table 7—Water used and the type test performed.

The results for these tests can be seen in **Figs. 12 and 13**. Two formulations were tested for each temperature modifying the gel loading from 25 (Test 1) to 30 ppt (Test 2). At low temperature, (Fig. 12) for stability test, a good value was observed with viscosity above 1000 cp (40 1/s) for both formulations. A stable response for the entire timed test was achieved. Choosing for this range of temperature was the 25 ppt fluid and then a breaker test was performed using an oxidant breaker (Test 3). High temperatures (Fig. 13) were identified as a better response in viscosity for 30 ppt fluid, and developing values were between 1400 to 1000 cp (40 1/s) at the end of the test. The breaker test performed (oxidant breaker) showed a good viscosity profile.

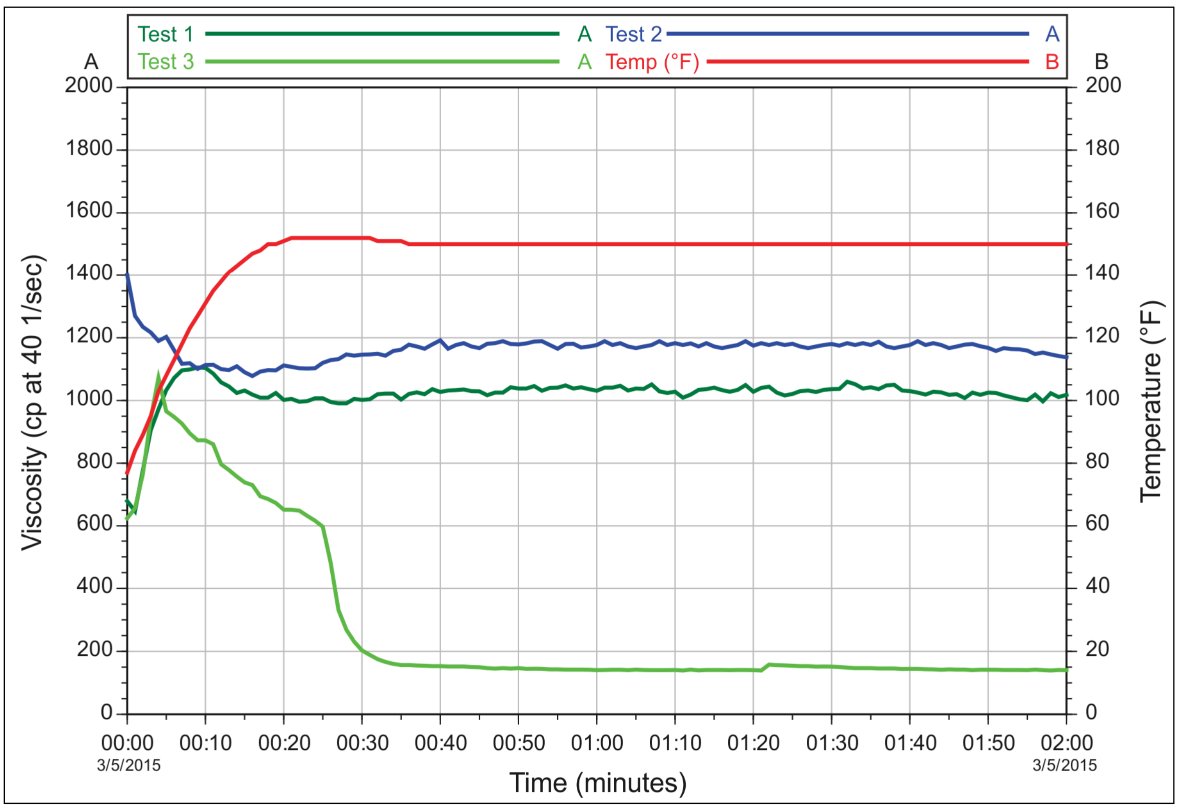

Fig. 12—Fracture fluid tests at 150°F.

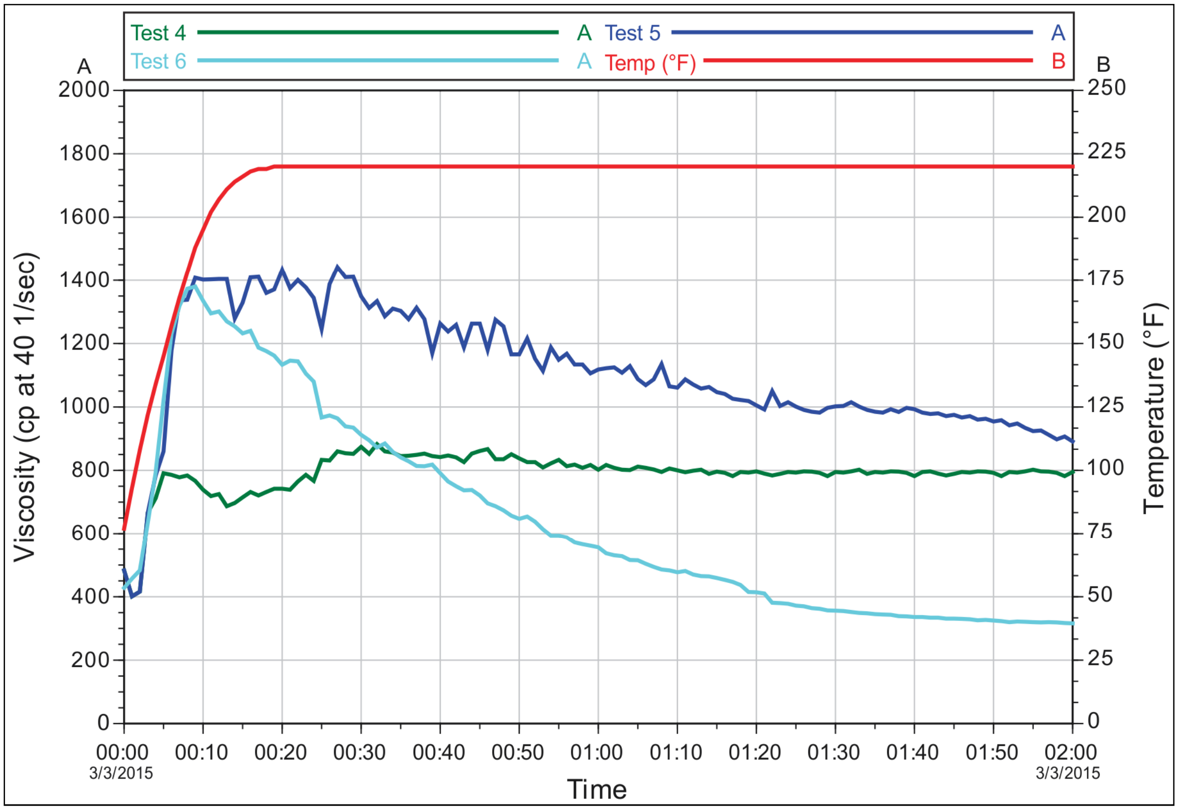

Fig. 13—Fracture fluid tests at 220°F.

Conclusions

In general, shale reservoirs are predominantly fracture stimulated using the hybrid (SW-LG-XL) type of treatment design, with varying total volumes of fluid per well from 5500 m^3 (vertical) to 18000 m^3 (horizontal). For tight reservoirs, it depends on the formation; there are some cases with hybrid (SW-XL or LG-XL), XL fracturing fluid or SW, the total volume per well varies from 1600 m^3 (vertical) to 2200 m^3 (horizontal).

The fluid storage systems that have been used are primarily tanks (mobile fracture tanks and circular tanks), which are usually located at the wellsite being stimulated. The system of water movement is performed mostly by trucks; however, there are some operators who have begun to develop pipeline transfer systems, which can lower costs and logistics. Most of the operators have used, as a water storage system, circular tanks for various sizes and capacities, for horizontal wells and multi-well pads water storage centers have been built relatively close to the wellsites.

For a large-scale development an integral water management plan has to be performed and take into account rivers, lakes, water wells, and synergies with other regional operator companies.

Nontraditional water sources analyzed (flowback-produced) for unconventional reservoirs revealed this information: Vaca Muerta, important values of TDS, calcium, magnesium, iron and strontium; Punta Rosada presented substantial values of TDS, calcium and magnesium; Mulichinco only presents higher values of iron, in general lower values of boron and barium were observed. It has been perceived that, for waters that have been treated using various methods (by service companies), important reduction in the TSS and iron content has been made.

The use of these nontraditional waters in the fracture treatments raises the point that there is no need to use clay stabilizers because of its power of inhibition (high salt content), which usually reduces costs related to the use of these chemicals. This has been observed for various tight and shales formations in Argentina.

In a previous work Bonapace et al. (2015), presents results about significant decrement to the displaced fluid according to the TSS content increase in nontraditional waters. This clearly demonstrates the necessity of treating such waters by considerably reducing the content of TSS, which can negatively impact the fracture conductivity pack.

There has been a significant decrease to the displaced fluid up to 96% (as the content of TDS, calcium, and magnesium ion increases) in nontraditional waters, for the floculants and insoluble component generated at high pH (10.5). This effect was not observed in the same water at low pH (5.5) and values of displaced fluid were close to deionized water The test showed a negative impact for the actions of floculants and insoluble components clogging the sandpack (fracture conductivity), when nontraditional waters were adjusted at high pH (many of the crosslinked fracture fluid used in the industry works in alkaline pH).

A new fracturing fluid, low polymer loading, and low pH, has been developed in the laboratory. It can be formulated with 100% of nontraditional filtered water only. This system was tested for shale and tight reservoir conditions in the Neuquen

Basin and for a wide range of temperatures (120 to 220°F), TDS, and ion content (calcium and magnesium).This fluid proved to have a good proppant transport capacity and is much cleaner than the traditional guar-borate/fresh water, used in Vaca Muerta stimulation.

Treatment and reuse of nontraditional water for future development of projects greatly mitigates the issue of fresh water requirements for unconventional wells and reduces volumes to be injected in disposal wells. Water reuse is a key factor for sustainable unconventional developments.

Nomenclature

CMHEC—carboxymethylhydroxypropyl cellulose
CMHPG—carboxymethylhydroxypropyl guar
CST—capillary suction time
DI—deionized water
FB—flowback water
gpt—gallon per thousand gallons
HPG—hydroxypropyl guar
LG—lineal gel
LWC—lightweight ceramic
Nqn—Neuquén
pH—hydrogen potential
PROD—produced water
ppt—pound per thousand gallons
SV—slurry viscometer
SW—slickwater
TDS—total dissolved solids
TSS—total suspended solids
XL—crosslinked gel
XRD—x-ray diffraction

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