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CDG in a Heterogeneous Fluvial Reservoir in Argentina: Pilot and Field Expansion Evaluation

D. Diaz and N. Saez, (YPF); M. Cabrera, (InLab); E. Manrique, (Independent Consultant); J. Romero, M. Kazempour, and N. Aye, (TIORCO LLC)

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Abstract

The Loma Alta Sur (LAS) field is a multi-layer fluvial sandstone reservoir in the Neuquén Basin, Argentina. Reservoir heterogeneities and adverse mobility ratio (30 cp oil) led to an early water breakthrough short after water injection started. After the evaluation of different IOR/EOR methods, the evaluation of Colloidal Dispersion Gel (CDG) was considered as a strategy to improve oil recovery in the field.

CDG pilot started in July 2005 in well pattern LAS-58. Pilot considered the injection of two slugs ($\approx$ 190,000 bbls each) separated by one year of water injection at the same injection rate ($\approx$ 1,000 bbl/d). Injected CDG used 300 ppm of an HPAM and Chromium as a crosslinker with a polymer:crosslinker ratio of 40:1. CDG pilot was concluded in October 2007. Pilot monitoring was supported by a comprehensive injection/production data analysis, tracer and injection profiles before and after CDG injection.

Projected ultimate incremental oil recoveries estimated in 2008 were approximately 62,000 m^3 (2.9 % of the OOIP). Incremental recoveries were reasonably validated as October 2014. Oil production response in some of the wells of pattern LAS-58 can be correlated with tracer injection before and after the first CDG slug. These changes were also corroborated by time-lapse injection profiles run over the period of the pilot tests. Most recent injection profiles suggest that possible permeability reduction generated by CDG was removed after several years of water injection. Based on the pilot reassessment, CDG injection is under evaluation in the same and different patterns of LAS field. Ongoing CDG evaluation is supported by detailed laboratory and field scale numerical simulation studies.

This study provides an updated evaluation of LAS CDG pilot validating projected ultimate recoveries, recent laboratory evidences of size distributions of CDG injected, rheologic measurements, and preliminary results of pilot history matching. Lessons learned during pilot evaluation and monitoring strategies will be also presented.

Introduction

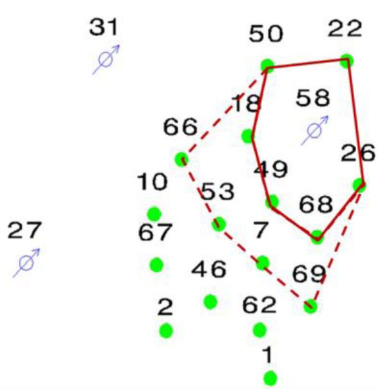
The Loma Alta Sur (LAS) field is located in the province of Mendoza in the Neuquén Basin of Argentina. The productive reservoir is the Grupo Neuquén Formation, which is characterized as heterogeneous lenticular channel-fill deposits of medium to fine grained sandstones. Diaz et al. (2008) provided a general geologic description of Neuquén Basin and LAS Field. LAS Field production began in 1990 with the well LAS-x1. After three years of primary production peripheral water injection started. In an effort to control the vertical distribution of injected water, injection wells were completed with downhole selective injection valves (mandrels).

Based on LAS permeability contrast and reservoir heterogeneity within the pay zone combined with an adverse mobility ratio justified the implementation of CDG as an in-depth volumetric sweep improvement strategy (Diaz et al., 2008). The use of CDG technology for in-depth conformance and as a mobility control strategy to improve waterflood sweep efficiency has been summarized in the literature (Castro et al., 2013; Leon et al., 2015; Manrique et al., 2014). In addition to project economics (benefited by low polymer concentration), the decision of implementing CDG in LAS over straight polymer flooding met the conditions reported by Manrique et al. (2014). Expected limited injectivity of highly viscous polymer gels (i.e. near wellbore treatment for injection profile modification) and an early tracer breakthrough (50–100 days) detected in the first row of offset producers (Badessich, et al., 2005; Diaz et al., 2008 and 2010) were also key variables to evaluate CDG technology in LAS.

This paper presents an update of injection and production performance, changes in operating conditions and well events of LAS-58 CDG pilot started in July 2005. A summary of tracer injection before and after CDG injection will be also presented. LAS-58 CDG pilot updates will be followed by a summary of recent laboratory and numerical simulation studies to improve CDG injection design to support the evaluation and possible project expansion in other patterns of the field.

LAS-58 CDG Pilot Summary and Updates

The CDG pilot was implemented in the LAS-58 injector located at the north-east side of the field. LAS-58 is an irregular pattern that began water injection in 2002 showing an early water breakthrough. The operator estimates that after three years of water injection the LAS-58 pattern, cumulative secondary oil recovery is only 5.48% of original oil in place (OOIP). Figure 1 shows LAS-58 pattern and summarizes average reservoir and fluid properties and tracer breakthrough times (summary table) before CDG injection started. LAS-58 pattern includes ten (10) producers, six (6) first line producers (solid red line polygon) with well spacing ranging from 138m to 164m; and four (4) second row of producers highlighted with the dashed red line polygon in Figure 1 (Diaz et al., 2008 and 2010).



General Reservoir and Fluid Properties	
Area, acres	57.3
Reservoir Temp., °C	45
Average Depth, m	450
Total Pay Thickness, m	35
Permeability Range, md	20 – 1000
Dykstra-Parsons Coefficient, v	0.89
Porosity, %	18.8
OOIP, m^3	2,169,000
API Gravity	21
Viscosity, cp	30
Tracer Breakthrough Times before CDG (days)	
LAS-18	50
LAS-49	112
LAS-26	147

Figure 1—LAS-58 pattern area, general reservoir and fluid properties and wells with tracer breakthrough before CDG started

The first tracer injection program was implemented in March 2003, three months after initial water injection in the LAS- 58 injector. Tritiated water was "bullheaded" simultaneously with all three injection mandrels open with an average injection rate of 190 m^3/d (March 15, 2003 to March 15, 2004). The fastest tracer breakthrough was observed in offset producer LAS- 18 (50 days). However, the amount of tracer recovered in LAS-18 and LAS-26 were below 1.5% of the total of tracer injected (740 Giga Becquerel - GBq). Producer LAS-49 showed the second fastest breakthrough but with a cumulative tracer recovered of 4% (Diaz et al., 2008 and 2010).

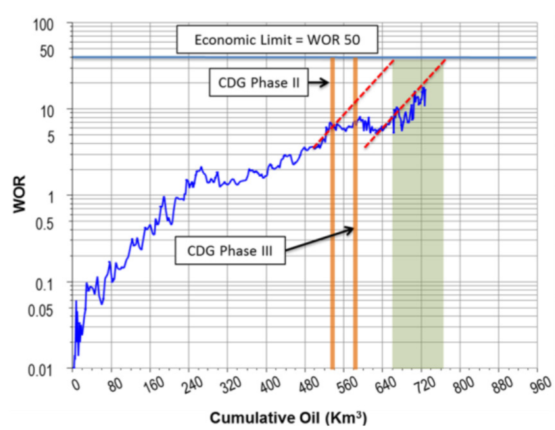
Once tracer data was evaluated and CDG was selected for field implementation, pilot test was started in 2005. The main objective of the operator was to evaluate a staged CDG injection to reduce water channeling, improve waterflood sweep efficiency, and potentially improve oil-water mobility ratio during CDG injection slugs as a secondary benefit. LAS-58 CDG pilot included three phases and are summarized in Table 1 (Diaz et al., 2008).

Table 1—Summary of CDG injection phases and conditions in LAS-58 pilot project

	Injection Period	Polymer Conc. (ppm)	Polymer:Crosslinker Ratio	Injection Rate (m^3/d)	Vol. of CDG Injected (m^3)	Maximum Pressure (Kg/cm^2)
Phase I	Dec. 15, 2004 – Jan. 1, 2005	600	40:1	170	1,986	30
Phase II	July 14, 2005 – Feb. 2, 2006	300	20:1	135	29,612	40
Phase III	April 7, 2007 – Oct. 31, 2007	300	40:1	140	30,581	39

Each of the CDG injection phase was followed by water injection at similar injection rates. Total volume of CDG injected (62,179 m^3) represented 3.06% of the pore volume (PV) of LAS-58 pilot area. Diaz et al. (2008) summarized pilot results for Phases I and II of the project only. However, it is important to remark that Phase I consisted in a small injection volume which was intended to test CDG injectivity, and did not impact pilot oil production response but definitively contributed to adjust polymer concentration used in the pilot through Phases II and III of CDG injection.

Main observation after Phase II of CDG injection was a very distinctive change in the injection profile of well LAS-58. The water injection flow paths were diverted into the middle (mandrel 2) and bottom (mandrel 1) zones of the pay zone due to the reduction in injectivity in the thief zones located at the top (mandrel 3) of the reservoir. As October 2007 the incremental oil production for the 10 offset producers was reported in 133,292 bbls (21,194 m^3) and a reduction in water production of 406,949 bbls (64,710 m^3). Based on the Water-Oil-Ratio (WOR) trends before Phase II projected to an economic limit of WOR of 50 an ultimate incremental oil of 389,968 bbls (62,000 m^3) was projected (Diaz et al., 2008). Following this similar approach, as June 2014 the ultimate incremental oil can be projected at 629,000 bbls (100,000 m^3) assuming the same economic limit (Figure 2). However, this incremental recovery does not include changes occurred in the pilot area after the injection of CDG that will be described below.



LAS-58 Pattern (Summary of Dates and Volumetric Parameters)		
Period	July 2005 to Oct. 2007	Oct. 2007 to June 2014
OOIP (m^3)	2,169,000	
Actual Incremental Oil (m^3)	21,194	49,400
Projected Ultimate Incremental Oil (m^3)	62,000	100,000
Actual Recovery Factor (%OOIP)	0.98	2,28

Figure 2—WOR vs. Np for all 10 producers of LAS-58 pattern and summary of volumetric parameters for the CDG pilot

It is important to mention that after CDG injection, several changes were implemented in LAS-58 pilot area as a strategy to optimize waterflood operations (i.e. workover in well LAS -7 and some producers converted into injectors). To take in account the aforementioned changes, projected ultimate incremental oil in LAS-58 pattern (as June 2014 - Figure 2) also include the conversion of three producers into injectors (Wells LAS-1, LAS-2, and LAS-10) shown in Figure 3. Wells LAS- 1 and LAS-10 were converted in August 2011 and well LAS-2 in February 2014. Increase in oil and water rates observed in December 2012 were possible impacted by the conversion of these three injectors (Figure 3). The oil response observed after well conversion was not included in the incremental oil reported (49,400 m^3) for the CDG pilot as June 2014. Therefore and under changes in flow pattern conditions, WOR vs. Np (Figure 2) can't be used to project ultimate recoveries of LAS-58 CDG pilot test.

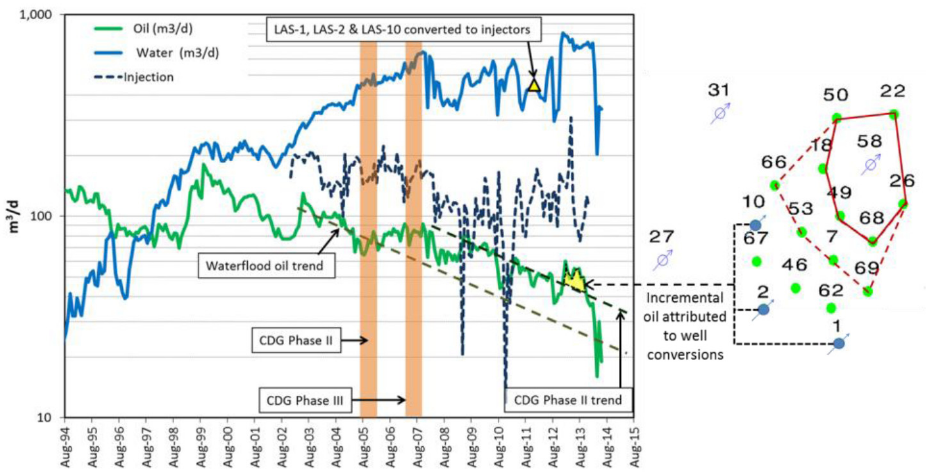


Figure 3—Injection and production history of LAS-58 pattern (10 wells) and map showing wells converted into water injectors

To estimate LAS-58 pattern performance hyperbolic decline curve methods was used for each of the 10 offset producers. During the first 20 months of the project (CDG Phase II followed by water injection) several wells showed positive response (Diaz et al, 2008). However, the largest oil response was observed during and after CDG Phase III as it will be summarized in the following section of this paper. Decrease in oil rates observed in June 2014 (Figure 3) is because most of the offset producers were shut-in and currently there is an ongoing evaluation to revitalize LAS waterflood.

Production Response of Individual Wells

As it was reported during the first pilot assessment (Diaz et al., 2008), well by well analysis reveals that oil production response in LAS-58 pilot area was not uniform. To provide a general overview of well production response, wells LAS-18, LAS-49, LAS-50 and LAS-53 were selected for a more detailed analysis. Producers LAS-18 and LAS-49 showed the fastest tracer breakthrough before CDG injection began (Figure 1) and wells LAS-50 and LAS-53 represents the producers with important cumulative incremental oil during the CDG pilot test.

Figure 4 depicts the injection (LAS-58) and production history of well LAS-18 and LAS-49. Wells LAS-18 and LAS-49 reported tracer breakthrough of 50 and 112 days, respectively. Despite an early tracer response neither of both wells reported the production of polymer during the injection of CDG. Well LAS-18 continues its oil decline during Phase II and incremental oil was observed 14 months after Phase III of CDG injection. WOR of LAS-18 remained reasonably stable at 10 until December 2010. Production response of well LAS-18 suggests that CDG injection reduced the existing transmissibility with the injector LAS-58. On the other hand, producer LAS-49 showed an increase in oil rate after two months of CDG Phase II started. However, early 2008 WOR showed a sharply increase requiring a well intervention.

Despite the early tracer response at wells LAS-18 and LAS-49, both reported reasonable cumulative incremental oil (3,000 to 4,500 m^3). In general all first line of producers (Figure 1) showed a higher oil production response after CDG Phase III, especially well LAS-22 (cum oil of approximately 7,000 m^3).

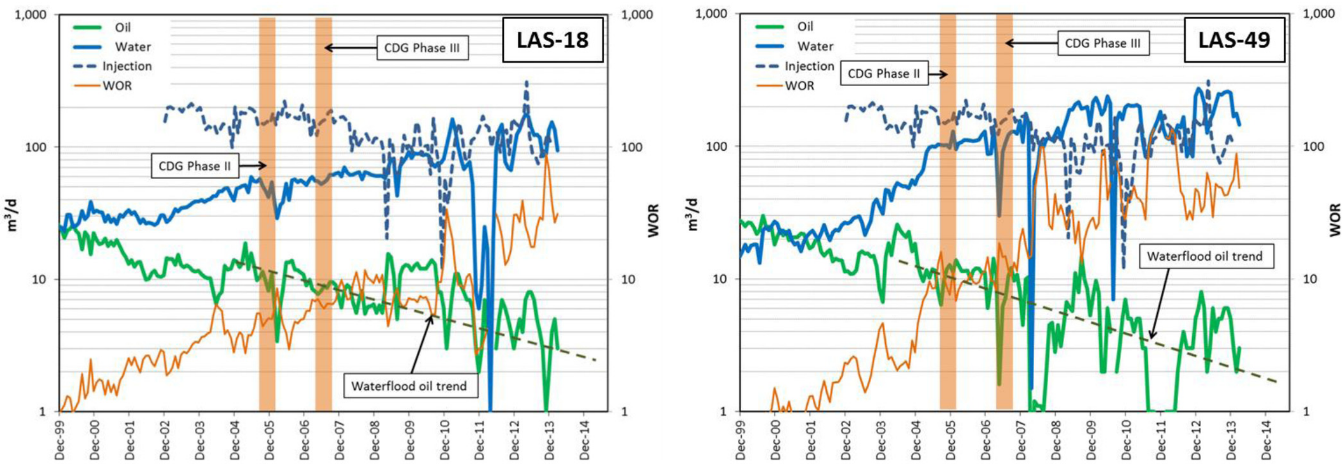


Figure 4—Injection (LAS-58) and production history of first row producers LAS-18 and LAS-49 of the CDG pilot area

Figure 5 shows historical performance of wells LAS-50 and LAS-53. Both wells showed similar oil production response after CDG Phase II. Well LAS-50 started to increase oil production 5 months after CDG Phase II ended. This well also shows a clear change in WOR trend and remained below 4 until December 2012 demonstrating the benefits of CDG injection, especially after Phase III. Well LAS-53 (Figure 5) is one of the producers with the largest cumulative oil production (≈ 11,000 m^3) during the period of July 2005 to June 2014. This second line offset producer started to mobilize oil during the injection of CDG Phase II. By July 2006 (a year later CDG Phase II started) LAS-53 steadily produce between 10 to 20m^3/d until 3Q of 2012 with a WOR below 10. It is believed that oil production response observed in this well after December 2011 was influenced by the conversion to injectors of well LAS-10 (Figure 3). Therefore, oil production recorded after this period was not included in the actual recovery factor of LAS-58 CDG pilot (Figure 2).

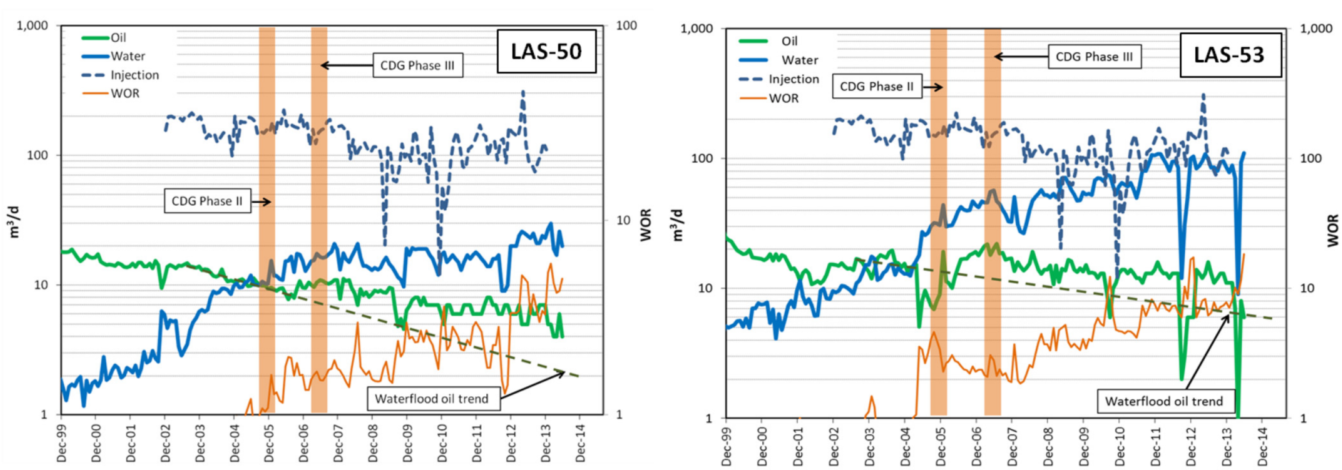


Figure 5—Injection (LAS-58) and production history of second row producers LAS-50 and LAS-53 of the CDG pilot area

Regarding other offset producers of the pilot, LAS-7 (2nd row) and LAS-22 (1st row) are among the wells with the largest cumulative oil production. Both wells started to show positive oil response approximately after 17 months of CDG Phase II began. During mid-2008 a successful workover (water zone isolation) in well LAS-7 decreased the WOR from 30 to 2 contributing with the oil production response of this well. It is also important to highlight that this sharp WOR reduction occurred approximately at the same time as a drop in injectivity in well LAS-58 (Figure 3). On the other hand, wells LAS-68 (1st row), LAS-66 and LAS-69 (2nd row) were minor contributors in cumulative oil production ($\approx$ 2,500 m^3 each) over the period evaluated (July 2005 to June 2014). Finally, it can be concluded that several wells (6 of 10) showed an increase in oil rate since the CDG injection started (Phase II). However, it was evident that main incremental oil was observed after the final slug of CDG as it will be described in the following section.

Injection Response and Post Tracer Injection

This section will provide a general description of Hall Plot, time-lapsed injection profiles and post tracer injection to support LAS CDG pilot interpretation. Hall plot is well known tool to monitor project performance of conformance treatments and EOR floods (Hall, 1963; Izgec and Kabir, 2011). The Hall plot was originally proposed to evaluate the performance of waterfloods and estimate skin effects in water injection wells (Hall, 1963). Buell et al. (1990) also proposed a method to use Hall plots for both water and polymer floods (Non-Newtonian fluids).

Figure 6 shows the Hall Plot of well LAS-58 including the incremental oil of the pilot area (10 wells). Details of LAS-58 Hall Plot were also summarized by Manrique et al., (2014). After approximately 130,000 m^3 of injected water, the injection rate was stabilized at an average of 176m^3/d for 6 months before CDG injection started (Waterflood pressure trend). CDG Phase II (29,612 m^3) was injected at an average rate of 135m^3/d followed by water injection at a similar rate. This injection period is highlighted with the CDG Phase II trend in Figure 6. A change in slope suggests the effects of in-depth conformance generated by CDG injection. The final slug of CDG ($\approx$ 30,581 m^3) was also pumped at an average injection rate of 143m^3/d. This slug (CDG Phase III) was followed with water injection at a similar rate for few months. At this stage injection rate was reduced to an average of 110m^3/d (CDG Phase III trend in Figure 6). It can be noticed that the change in slope in incremental oil was observed approximately 18 months after the end of CDG Phase III. Injectivity reduction and the increase in injection pressure clearly suggest that CDG injection generated a clear water diversion to unswept and lower permeable zones in the reservoir.

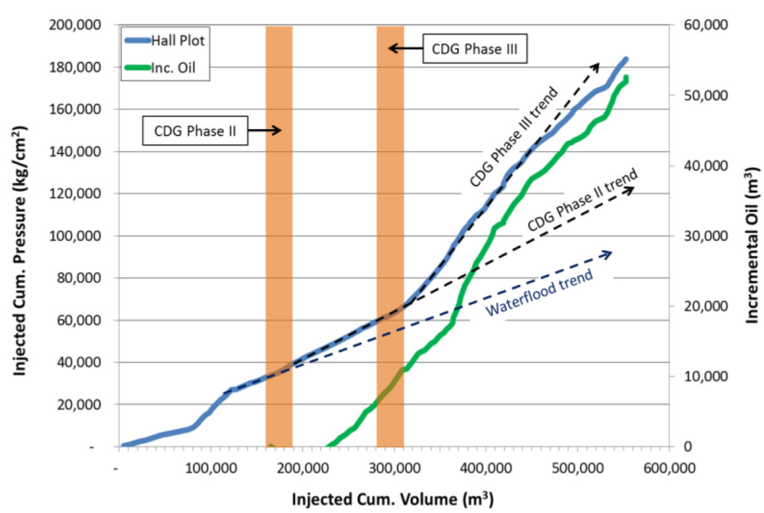


Figure 6—Hall plot and incremental oil recovery (10 production wells) of LAS-58 CDG pilot

Changes in water injection profiles (vertical tracer surveys) were run before and after CDG injection. Diaz et al. (2008) reported changes in water injection profiles before and after CDG Phase II (Figure 7). It is important to mention that the average net pay of LAS-58 is approximately 38m. Wellhead pressure during the injection profile before CDG injection started was 6 Kg/cm^2 at a rate of $158m^3/d$. Injection profile after CDG Phase II was recorded at 30 Kg/cm^2 at an injection rate of $162m^3/d$. Mechanical problems in the injector LAS-58 limited running representative injection profiles. Figure 7 also shows two injection profiles run during 2011. Injection profile of February 2011 was run in the upper sands only due sand accumulation in the middle and bottom zones limiting the access of the tool. It can be noticed that injection profile in the upper sand shows that the water intake is similar than the observed before CDG injection began in July 2005. This injection profile was run at $105m^3/d$ with a wellhead pressure of 45 Kg/cm^2. However, the upper sand (Mandrel 3) of well LAS-58 has a thickness of 8m, only 21% of the total net pay. From this injection profile (Feb. 2011) it can be inferred that the transmissibility reduction generated by CDG injection (Phase II and III) was partially or totally removed after more than three years of water injection since the end of CDG Phase III. In August 2011 (Figure 7) another injection profile was run but for the middle and bottom pay zones (Mandrels 2 and 1). This survey still indicates a positive variation of the injection profile. However, injectivity was reduced due to water diversion into lower permeable zones as shown in the Hall Plot (Figure 6). This behavior was expected based on the better connectivity and areal development of the upper sand sequences (Mandrel 3) than the lower layers (Mandrel 2 and 1) as described by Diaz et al. (2008).

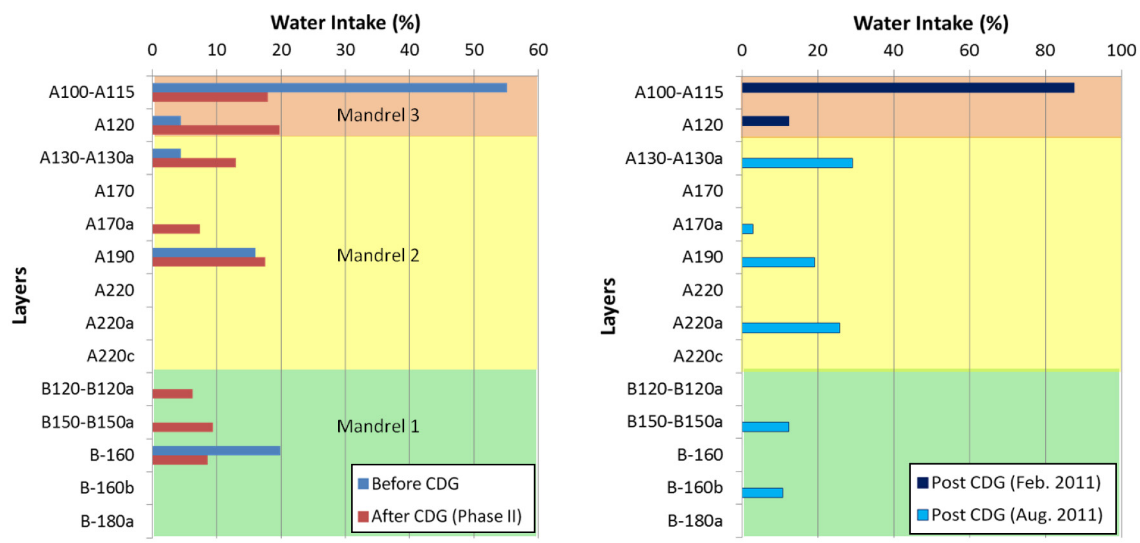


Figure 7—LAS-58 Injection profiles before and after CDG

In 2013 running additional injection profiles were attempted but again mechanical problems (i.e. casing diameter reduction) limited running reliable tracer surveys. At the time this paper was written, well LAS-58 was repaired and it has scheduled an injection profile during 3Q of 2015. This injection profile will be used to compare the injection profile run before CDG started in July 2005 (ten years after the pilot project started).

In June 2006, a second tracer program was run after CDG Phase II. However, this tracer program was run using a different strategy. As it was described earlier in this paper, during the first tracer program (March 15, 2003 to March 15, 2004) tritiated water was bullheaded simultaneously in all three zones (mandrels). The second tracer program was run injecting tracers selectively in each of the mandrels. Therefore, results must be interpreted with care when comparing tracer results from both programs.

Second tracer program injected Yellow Acid in Mandrel 3 (Upper layer), tritiated water in Mandrel 2 and Ammonium Thyocianate in Mandrel 1 (Diaz et al., 2008 and 2010). Injection profile after CDG Phase II shown in Figure 7 (red bars) was run few months before tracer injection began. As expected, the fastest tracer arrival was observed in the upper layers (Figure 8) due to higher permeabilities and flow distributions observed in the injection profile.

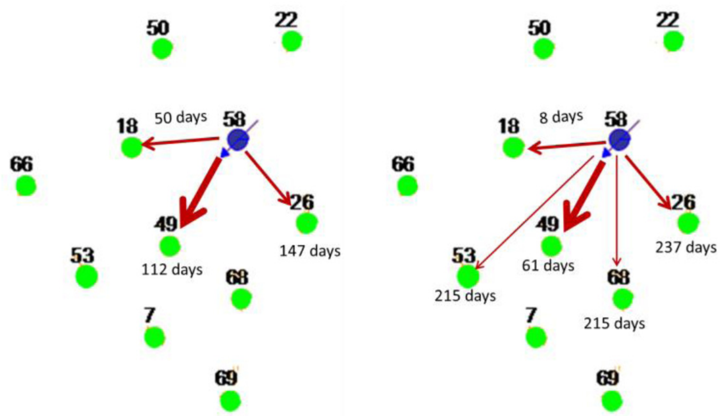


Figure 8—Tracer response in the upper layer (Mandrel 3) of LAS-58 pilot area before (left) and after (right) CDG Phase I

Overall, second tracer program confirms production performance of the CDG projects in LAS-58. The later can be supported based on the oil production response which was observed after the completion of the CDG Phase III. A summary analysis of the second tracer program (Post CDG Phase II) is summarized below:

- Wells LAS-18 and LAS-49 still are the offset producers with the fastest and largest tracer production (in all three zones). Fastest tracer breakthrough can be also attributed to the smaller pore volume (Tracer injection per zone vs. the whole pay interval). Earlier tracer breakthrough observed in producer LAS-18 can be justified because it was not impacted by CDG Phase II as it continuous its oil decline rate. Contradictory, well LAS-49 showed oil response during CDG Phase II and water injection potentially creating new thief zones in the upper layers (Figure 4).
- Producer LAS-68 also showed tracer in all three layers but reported recoveries were below 1%. This well did not report tracer production during the first program but showed oil response during CDG Phase II and post waterflood. This effect may have created some water channels that facilitated the communication of the water phase between wells LAS-58 and LAS-68.
- Later tracer breakthrough recorded in the upper layers of well LAS-26 (Figure 8) could be attributed to an effective transmissibility reduction of the upper layer during CDG Phase II diverting water flow into the middle and bottom layers in this direction of the pattern.
- Offset producer LAS-53 also reported tracer response confirming preferential flow towards well LAS-49. However, tracer mass recovered was also below 1%.
- Surprisingly and despite the oil response observed in offset (1st row) producers LAS-50 and especially LAS-22 (north LAS-58 in Figure 8) since CDG Phase II started, did not reported tracer response.

Finally and after almost ten years since CDG injection started, it can be concluded that LAS CDG pilot was technically and economically a success. However, based on the lessons learned during and after the injection of CDG in the field, there are enough room to improve the performance of this Chemical EOR method in LAS and potentially analog fields in the country. To evaluate new options and potentially expand CDG injection in this mature waterflood, detailed laboratory and numerical simulation studies started in 4Q of 2014 as part of LAS waterflood revitalization. Preliminary results of these ongoing studies will be summarized in the following section.

Laboratory and Simulation Studies

A detailed laboratory study was designed to improve the understanding of CDG technology under LAS reservoir conditions. The laboratory study includes the characterization and ongoing coreflooding tests of polymer and CDG at similar conditions. Main objectives of this study were to evaluate CDG properties (i.e. viscosity and size distributions) and polymer flood and CDG injection at Sorw (irreducible oil saturation to water) in reservoir cores using the same polymer concentration. Regarding the size distribution of CDG, it was decided to perform this analysis to evaluate possible differences or similarities with LPS (Linked Polymer Solutions) technology documented in the literature (Aarra, et al., 2005; Bjørsvik et al., 2008).

Polymer and CDG solutions were prepared using LAS synthetic water, high molecular weight HPAM polymer (EOR360) and Chromium Acetate ($CrAc_3$) as a crosslinker. Polymer and CDG solutions were tested with and without KSCN (30 to 50 ppm) to evaluate the effects of oxygen scavenger. Polymer concentrations tested were 300, 400 and 500 ppm, and polymer:crosslinker ratios of 20:1 and 40:1, similar to conditions tested in LAS-58 pilot test (Table 1). Finally, polymer and CDG solutions were tested at different temperatures: 25°C (surface conditions), 33°C (downhole injection), and 42°C (reservoir temperature).

Figure 9 shows an example of polymer and CDG viscosity (Brookfield dynamic viscosity) and size distributions (Malvern Nanosizer S) using polymer concentration of 300 ppm, polymer:crosslinker (P:CLX) ratio of 40:1 at 42°C and measured at different times. Tested CDG system showed a good and stable viscosity over time. It can be noticed that polymer solution and CDH freshly made (time 0 h) shows similar viscosities over the range of shear rates evaluated. After 24 h, CDG viscosities are higher (60–80 cP @ 10 s^{-1}) than polymer (3 cP @ 10 s^{-1}) solution at the same polymer concentration (300 ppm). This trend is opposite to LPS where polymer viscosity decreases in the presence of crosslinker. However, LPS viscosities have been reported using Aluminum Citrate as a crosslinker and a different high molecular weight HPAM (Bjørsvik et al., 2008). Therefore, laboratory results of this study can't be used to establish possible differences between these two systems. Regarding the size distributions (Figure 9) of polymer (dashed light blue line) and CDG (Solid dark blue line) it can be noticed that at time 0 (Polymer with crosslinker recently added) size distribution are smaller suggesting than the polymer suggesting it is coiling up by intra molecular crosslinking as reported by Spildo et al. (2010). However, after 24 hours (red dashed line) it can be noticed the formation of larger aggregates (≈ 1 micron) which suggest that CDG's are dominated by inter molecular crosslinking and/or a combination of intra/inter molecular crosslinking (Spildo et al., 2010). Size distribution observed in this study clearly suggests a difference with LPS size distribution (20 to 150 nm) reported in the literature (Aarra, et al., 2005; Spildo et al., 2010). However, CDG tested in this study and LPS studies are based on different polymers and crosslinker in addition to different experimental conditions making comparison difficult to be made between the two systems.

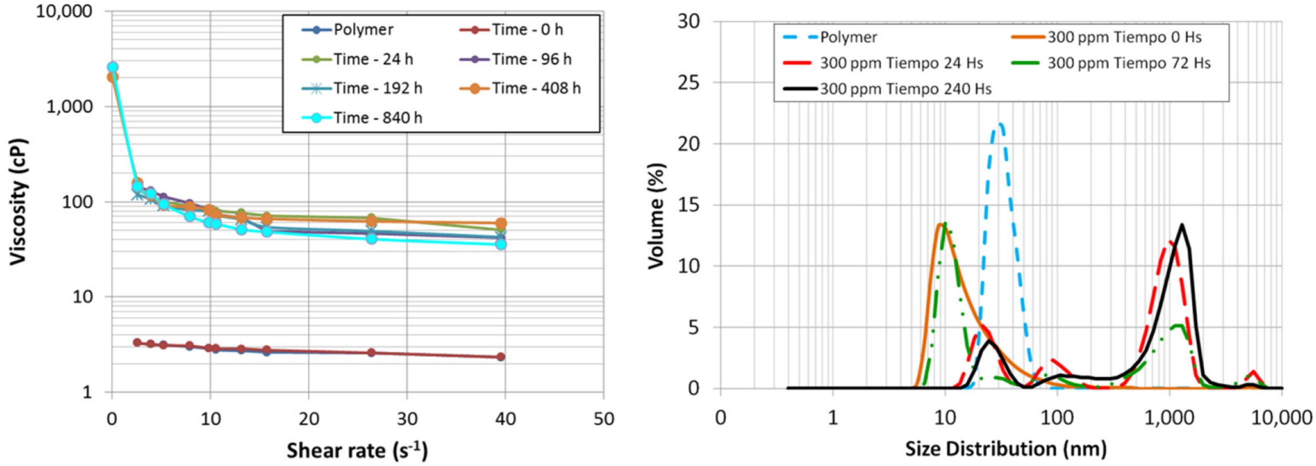


Figure 9—Polymer and CDG viscosity and size distributions vs. time (P = 300ppm; P:CLX = 40:1 and T = 42°C)

Core plugs cored from well LAS-72 were used to run corefloods comparing polymer flood and CDG (P:CLX of 40:1) at Sorw using the same polymer concentration (300 ppm). Core plugs used has porosities and air permeabilities of approximately of 29% and 1,200 md, respectively. Fractions of cored material were used to run capillary pressures, pore, and pore throat size distributions by mercury injection (Micromeritics Autopore 9500). Pore throat size distributions of four samples ranged from 6 to 100 microns with a peak average of 23 microns. Corefloods were supported by the injection of tracer to estimate polymer adsorption and inaccessible pore volume (IPV). Coreflood results and its interpretation including tracer analyses are underway at the time this paper was submitted. However, detailed results of this laboratory study are expected to be presented in a different publication.

Preliminary numerical simulations studies started before laboratory studies began. Once corefloods are concluded and properly history matched, the information will be used to update and evaluate different history matching approaches at field scale. This information will be used to run performance predictions and rank additional patterns for possible CDG expansion in the field. LAS full field model was history matched in Eclipse. The approach to history match LAS-58 pilot area included bottom aquifer support, transmissibility multipliers in I and J direction and changes in injection profiles run during the life of the flood. A second approach to support numerical simulation studies included the conversion of the available model into CMG-STARS. Conversion was relatively straightforward but the bottom aquifer supporting the production of LAS Field. Once the converted model was validated, a sector model was cut including LAS-58 pilot area. Figure 10 depicts sector model including LAS pilot area and also an example of permeability distribution between injector LAS -58 and first row offset producers LAS-22 and LAS-49. To analyze oil response from primary production to CDG pilot and post waterflood, two areas were defined in LAS-58 sector model. The first sector (AA) includes pilot injector (LAS-58_ij) and the first row of offset producers (LAS 18, 22, 26, 49, 50, and 68). This sector is highlighted with the blue dashed line in Figure 10. The second sector (AB) includes the first sector and four additional offset producers or second row of producers (LAS 07, 53, 66, and 69). Sector AB is highlighted with the magenta grid block in Figure 10.

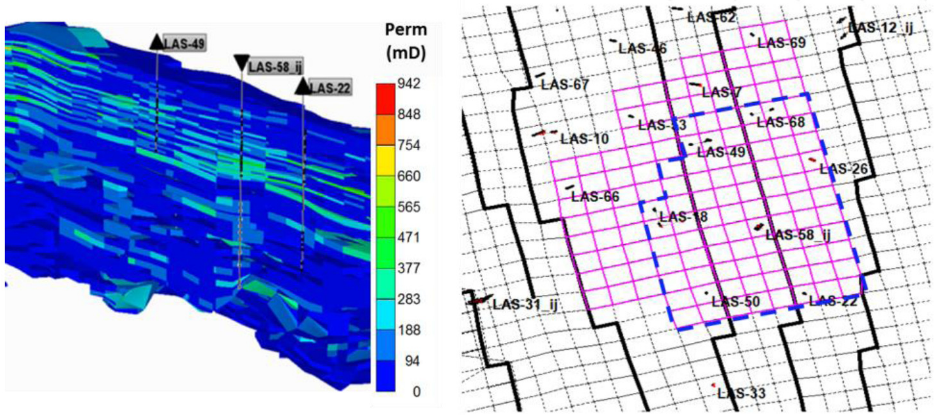


Figure 10—Model pilot area and permeability distribution between injector LAS-58 and offset producers LAS 22 and LAS-49

High level of reservoir heterogeneity and adverse mobility ratio lead to low oil recovery factors. Numerical model properly capture low recovery efficiencies observed in LAS Field including LAS-58 pilot area (Figure 11). CDG history matching strategy using transmissibility multipliers and injection profile modifications generates reasonable results. However, additional efforts are underway to properly match tracer response observed in both programs.

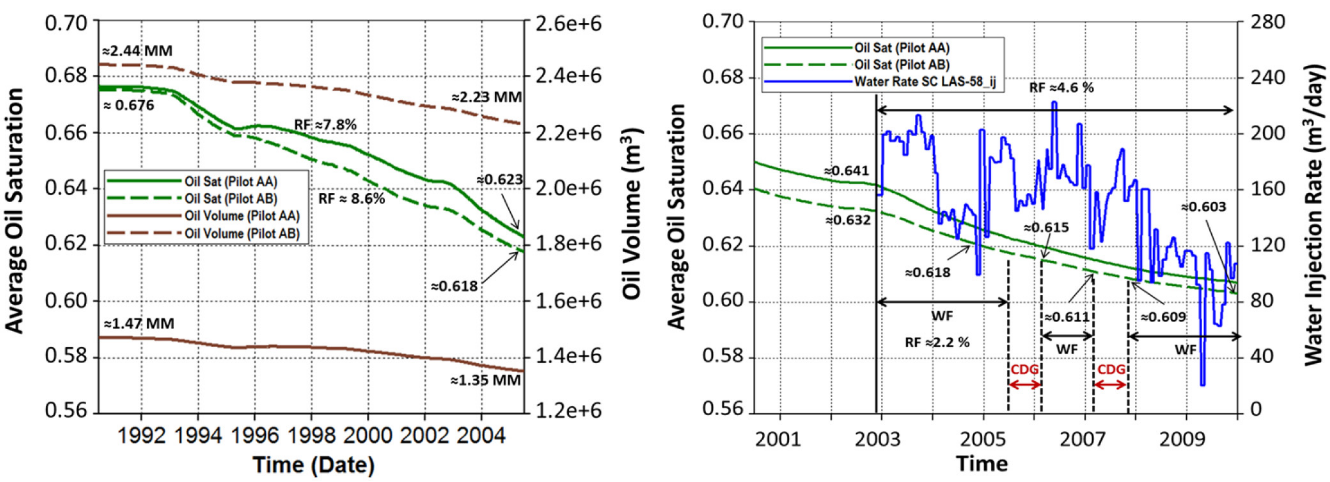


Figure 11—Average Oil Saturation and Volume in Pilot Area

Future modeling efforts will incorporate different approaches for CDG simulation and strategies to optimize CDG injection in LAS. Optimization strategies under consideration include CDG alternated polymer injection and adjust CDG slug sizes and/or frequency to accelerate oil production, among others.

Conclusions

- Colloidal Dispersion Gels (CDG's) was successfully implemented in Loma Alta Sur (LAS) Field. Incremental oil recovery is reported in 49,400m^3 (2.3% of the OOIP). Largest oil response was observed few months after the last phase of CDG injection.
- No polymer production or significant operational problems were reported during all CDG injection phases
- Based on incremental oil quantified as of June 2014, the cost per incremental barrel of oil is approximately $US 2.24.

- Laboratory studies indicate that CDG can generate higher viscosities than polymer solutions at the same polymer concentration. CDG showed the formation of aggregates in the range of 1 micron suggesting inter molecular crosslinking and/or a combination of intra/inter molecular crosslinking.
- The operator is currently performing detailed reservoir characterization and numerical simulation studies to evaluate the potential of CDG technologies and possible hybrid injection schemes in different patterns of the field.

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