New Polymer Technology for Sand Control Treatments of Gas Storage Wells

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Abstract

A new polymer technology has been successfully implemented in two Gaz-de-France Underground Gas Storage (UGS) facilities. The technique uses water-soluble polymers and microgels having a strong tendency to adsorb on the surface of the rock, thus forming a protective film to prevent the erosion process. All products have RPM properties (Relative Permeability Modifiers), i.e. they affect little gas relative permeability while reducing strongly the relative permeability to water. They can thus be injected into the whole open interval (bullhead injection) without specific tools for placement. A long post-flush of gas is injected after the polymer treatment to re-saturate the formation around the wellbore and check gas injectivity. Seven wells have been treated so far with the following results:

- All treatments were successful in stopping sand production
- The first treatment lasted about four years, after which it had to be renewed. All other treatments show long-term efficiency.
- Only one well suffered from a loss in Gas Productivity Index (around 20%), for all the others, gas injectivity and productivity remained unaffected by the treatment.
- The well treated with microgel has been producing much less water than before, in addition to the stopping of sand production.

Introduction

High-molecular-weight water-soluble polymers are known to adsorb irreversibly on reservoir rocks and thus affect two-phase flow behavior. The most remarkable effect is the ability for these products to reduce selectively the relative permeability to water with much lower impact on the relative permeability to oil or to gas. This property also known as “RPM” effect (Relative Permeability Modification) has a practical application in water shutoff treatments of production wells. Some pioneer works have also shown that the formation of an adsorbed polymer layer covering the pore walls acts as a clay stabilizer and thus reduces both clay swelling and fine migration in unconsolidated or poorly consolidated sandstones. The present paper describes how this property has been successfully used in sand control treatments of gas storage wells.

Underground gas storage (UGS) wells in sandstone aquifers often encounter problems of sand production due to the destabilization of the wellbore after several cycles of injection and production of gas. In many cases, the sand produced consists of fines, which are not retained by stand alone screens. When facing these problems, and to prevent the degradation of well completion and surface installations (valves, pipe,…), the operators choke the well and limit the gas production rate, which, in addition to frequent sand cleaning jobs, increases operational costs. The degradation process of the rock starts with the erosion of the cement of the rock, with a production of fines at the surface, then, when the erosion of the cement is advanced, rock degradation leads to a production of sand grains at the surface together with sand accumulation in the well. The principle of the polymer sand control technology consists of the formation a polymeric film on pore walls, which can stabilize the rock around the wellbore, and thus stop (or at least slow down) the erosion process (Fig. 1). Such a film has to be strong enough to resist to the harsh hydrodynamic conditions of gas flow at high velocity through pore channels, with alternate flow of dry and wet gas flowing in two opposite directions.

Recently, the same concept of building a protective film on the surface of the rock has been successfully applied in the treatment of oil wells by organo-silanes. This type of oil-soluble product reacts with water to form a silicate gel. In the proposed technology the product is diluted in diesel oil, then injected into the formation at a distance of several feet.
product is expected to react with connate water to form a protective layer of silicate gel on the surface of the rock. As oil-soluble product, adverse impact on oil permeability is reduced. The technology has been applied in six wells of two offshore fields with a success rate of about 66%, and a treatment lifetime of several months.

Although based on the same concept of protective film, the sand control technology we are dealing with uses water-soluble polymers or microgels which are diluted in water before being injected into the well. The products adsorb strongly on the surface of the rock, and, due to RPM properties, affect little oil or gas permeability. Polymer solutions can thus be injected through the whole open interval, in a “bullhead” mode. The product is expected to invade more deeply the highest-permeability layers, which are often the most sand productive layers. Self-placement into the most problematic zones is thus favored. The environmental impact is also minimized because of the use of non-toxic water-soluble products.

The first treatment was performed in 2001 and, due to positive results, was followed by six other ones between 2005 and 2007 (in two Underground Gas Storage facilities). The first well was re-treated in 2008 by the same process. Polymer technology has also been applied for water shut-off applications in gas storage wells with mixed results. Among the different sand control treatments described in this paper, one of them (using microgels) has been shown to reduce significantly water production, without any adverse effect on gas. A previous paper describes this field test. We have to point out that such a synergistic water control/sand control effect has been previously observed in polymer treatment of heavy-oil wells.

In the first part of the paper, we present the laboratory procedure used to design a treatment. In the second part we present field results.

**Laboratory tests**

An original method was used for the design of the treatment, consisting of flocculation tests and coreflood experiments. We have to point out that the technology is based on a weak but deep chemical treatment and not on a solid-like consolidation process as with resins. Conventional measurements of rock stability with consistometers are thus not useful in the present case.

Since the process consists in coating the surface of the rock by a polymeric film, an empirical method was chosen to evaluate the coating capability of a given polymer on reservoir sand. Flocculation tests were designed for this purpose. In these tests, we mixed a given quantity of sand with a polymer solution in a graduated ampoule having two graduations to detect flocculation time. The tube was gently reversed four times to mix the sand with the polymer solution, then allowed to settle. Flocculation time is simply measured as the time needed for the solid/liquid interface to pass the two graduations. As a first approximation, we may assume that the shortest the flocculation time, the highest the ability for the polymer to coagulate the sand (thus to “coat” the sand). Figure 2 shows photographs of sand before and after contact with polymer, giving large “flocs”.

*Fig.1: Principle of Sand Control Polymer Treatment*
Figure 3 shows the results of a series of flocculation tests performed with the same sand (collected at the bottom of the borehole after a sand clean-out job) and different polymer products. A blank (without polymer) is first established as a reference. The flocculation time is measured at different intervals of time for the four ampoules containing the solutions of the different products. The test shows that all products are efficient flocculants, thus have a coating capacity. Nevertheless, a ranking can be established, with Product A > Product C > Product B > Product D. The test also shows that there is a slight degradation of flocculation properties versus time. To compare product performances it is thus mandatory to perform all the tests in the same experimental conditions.
Once a polymer product has been selected as efficient coating material for the reservoir sand, we proceed to polymer injections in reservoir cores. The coreflood program consists of the following steps.

3. $CO_2$ flush and resaturation with brine until $Sw=100\%$.
4. Injection of first polymer slug + tracer.
5. Brine injection to displace non-adsorbed polymer.
6. Injection of second polymer slug + tracer. Measurement of polymer adsorption by delay of 1st polymer front vs. 2nd one.
7. Injection of three polymer slugs at increasing concentrations. Measurement of Mobility Reduction $Rm$ curves.

The coreflood experiment aims at:
- Evaluating polymer injectivity in reservoir core.
- Measuring polymer adsorption.
- Providing $Rm$ and $Rk$ data set, which can be used in reservoir near-wellbore simulations to determine polymer placement in the different layers.

Ideally, one coreflood per rock type has to be performed to have a complete data set for treatment design. In practice, the number of corefloods is limited to two (for example one high-permeability and one low-permeability core), using extrapolated values for the rock types with intermediate petrophysical properties.

Figures 4 and 5 give experimental results obtained during microgel injection in a high-permeability reservoir core. For a solution having a relative viscosity of $\mu_r=6.0$, the Mobility Reduction level is $Rm=9.0$ and the Permeability Reduction to water is $Rk=2.25$. The relative permeability to gas remains almost unaffected by the presence of the adsorbed layer (Fig. 5) thus showing very good RPM properties. Such a behaviour enables bullhead injection of the product throughout the whole open interval, without requiring mechanical tools, such as retrievable packers or sleeves, for polymer placement.

![Polymer injection in reservoir core](image)

**Fig. 4: Microgel injection in a high-permeability reservoir core: Mobility and Permeability reduction curves**
Products

Several products have been tested in the laboratory, and many of them are currently commercially available. The products can be classified in two main families, i.e., (1) polymers and (2) microgels. Polymers are large flexible linear chains, behaving as soft coils in a relaxed state. Microgels are more rigid species due to the existence of crosslinks between molecular chains. Microgels are now available at several sizes ranging between 0.3 and 2.0 microns. Figure 6 compares a high-molecular-weight linear polymer (whose coil size is around 0.3 μm), with three microgel species, one large “hard” microgel with a size of 2.0 μm and a high crosslink density, one large “soft” microgel with the same size, but low crosslink density, and one small microgel with a size of 0.3 μm and a high crosslink density.

Due to the existence of internal crosslinks, microgels are more resistant than polymers, withstanding strong shearing conditions, high temperatures (up to 165°C), high salinity and harsh chemical environments (presence of CO₂, H₂S, ...). Also the large size of some microgel species enables the coating of the surface of the rock with an adsorbed layer thicker than with conventional polymers.
All polymers and microgels developed in this application are friendly water soluble products. They are usually simply dissolved in water and injected in the “bullhead” mode into the whole open interval. Due to their RPM properties, they have low impact on gas permeability and can, in favorable cases, reduce water production along with the positive impact on sand production.

Field results
Between 2001 and 2008 seven wells were treated with the new sand control technology in two different UGS facilities operated by GDF Suez in France, namely, Germigny-sous-Coulomb and Cerville-Velaine. Both are natural aquifers converted to UGS reservoirs in the 1960/1970s. The reservoirs are made of good quality sandstones with permeabilities ranging between about ten mD and several Darcy, with alternate of good and poor pay zones over a thick open interval (about 30 m for Germigny and 60 m for Cerville). Many wells, which originally do not produce sand, face severe sand problems after several cycles of dry gas injection followed by wet gas production. The origin of the phenomenon seems to be due to the destabilization of the cement of the rock by a combination of high gas flow rate and strong changes of wetting conditions around the wellbore. Excessive water production may also contribute to rock de-cohesion.

All wells have open-hole completions with stand-alone wired screens. Sand production occurs in two stages. At an early stage, the sand is essentially made of fines with grain size below 50 μm. These fines are not retained by the screens and thus are produced at the wellhead. At a later stage, sand grain distribution becomes broader with a significant amount of large fractions (above 100-150 μm). Such a behavior reveals a degradation of both the rock surrounding the wellbore and the sand control completion. Sand grains produced with gas at very high rates are very abrasive materials and can damage surface equipments (valves, pipes, chokes). To prevent such degradations, the operators have to choke the well below the critical rate of sand production. In summary sand production in UGS causes the following problems.

- Reduction of gas production rate
- Sand accumulation in the wellbore and in surface facilities (requiring frequent sand cleaning jobs)
- Damage of equipment in the well and in surface facilities (with safety concerns)

In 1986 and 1991, two polymer treatments were carried out in GDF Suez UGS wells for Water Shut-Off purposes, with positive results, although of difficult interpretation. In July 2001, GDF Suez decided to perform a new treatment on a well suffering of both water and sand problems in Germigny (Well CR-24). Regarding previous WSO polymer treatments, it was decided to use polymers with a higher adsorption tendency and to spot a small slug of gel after the polymer slug to strengthen the treatment close to the wellbore.

Make-up water was tap water + 1%KCl. The polymer was injected at a concentration between 1000 and 4000 ppm. The first polymer batches were injected at the lowest concentration, then, we proceeded to concentration ramp-up for the following batches. The last batch consisted of a gelling mixtures having a delayed (10 hours) gelation time. Before polymer, two batches of 1% KCl brine were injected to check well injectivity. All injections were performed in “bullhead” mode throughout the whole open interval. Downhole pressure was monitored continuously via a logging unit. A scheme of surface equipment is given in Figure 7. Polymer solutions were prepared in two 10-m³ tanks equipped with paddle mixers and pumped into the well by a triplex pumping unit. Pumping rate was maintained around 10m³/h (1 BPM). Downhole pressure was kept below 12,000 kPa. The polymer was delivered on site as a liquid concentrate (1.25%) and each batch was prepared by addition of a certain volume of polymer concentrate and dilution with 1% KCl brine up to 10m³. The treatment was followed by continuous gas injection for several days in order to check gas injectivity and reconnect the well to the gas bubble. Treatment volume was 100m³, which gives an average depth of penetration of 3 to 4 meters.

Well CR-24 performances were carefully monitored for several years after the treatment in terms of water and of sand production. I appeared clearly that sand production was almost stopped whereas the level of water production remained high without any obvious tendency to decrease. Sand monitoring is achieved in two ways, i.e. (1) top sediment check at the end of each gas production period, and (2) well tests to evaluate sand production level at several gas production rates. This type of measurement is achieved with a Clampon™ detector placed at the wellhead and converting the chocks of sand grains on the pipe into electric signal (Fig. 8). The Clampon™ detector is also used to find out the critical rate of sand production and to identify candidate wells for a treatment. Figure 9 shows comparative results obtained on three neighboring wells on February 2005, i.e. 4 years after the treatment. The three wells were submitted to comparative gas rates (gas rate levels are given in pink in Figure 8). Well A, which is CR-24, produces much less sand than the two neighboring ones, which shows that the treatment remains efficient to control the sand movements after four years of gas injection and production. Well CR-24 started to produce again large quantities of sand from 2006. This result gives lead us to estimate of the duration time of a treatment as four years approximately.
Fig. 7: Field handling equipment

1. Pumping unit
2. Water storage tank
3. Polymer mixing tanks (2 x 10 m3)
4. Trucking (water and polymer concentrate)
5. Logging unit
6. Sampling valve
7. Well head

Fig. 8: Sand detection tool (Clampon™)
The positive results obtained with the new sand control polymer technology on Well CR-24 lead GDF Suez to perform new campaigns of treatments on several other wells in Germigny. In 2006, four wells were treated with the new technology. Among the four candidates, two wells were considered as “neo” sand producers, while the two other ones were considered as “paleo” sand producers. The first category corresponds to wells at an early stage of sand production (mostly fines). The second one corresponds to “old” sand producers (with more coarse sand grains). Due to the positive results obtained with CR-24 it was decided to keep treatment procedure unchanged as well as the products and the volumes of the different slugs. The four treatments performed in 2006 have been successful, all wells producing almost no sand after treatment. Only for one well, we observed a loss of gas productivity index estimated as 20%, whereas for the three other wells, no adverse effect on gas was detected.

In 2007, another well from Germigny UGS was submitted to the same type of treatment. On the contrary of the previous ones, this well was used as observation well only, because sanding up even without any gas movement (probably due to strong crossflow between the different layers). For this “severe” case, it was decided to double the volume of the treatment up to 200m³. In 2008, it was decided to treat Well CR-24 again with the same process, the positive effect of the first treatment being lost since 2006. Although not having long post-treatment history, both wells seem to produce much less sand than before, thus showing that the treatment can be repeated on the same well with good performances.
In 2005, GDF Suez decided to test a microgel sand control treatment in Cerville UGS. Candidate Well VA-36 was suffering of both water and sand problems. The specific configuration of the reservoir around the well, with a high-permeability streak located at the bottom part of the open interval, called for a microgel treatment to have a significant impact on water production. A detailed description of this field case is given in Reference 11. Due to injectivity constraints, the volume of the treatment was reduced to 26m³ only. In spite of the reduced volume effectively injected, the results have been remarkably successful, the treatment inducing a stop in sand production (Fig. 10) and a reduction of water production by a factor of three to four, for at least three years. Further treatments in GDF Suez UGS facilities are scheduled on 2009 with both polymer and microgel sand control technology.

Conclusions
A new polymer sand control technology has been successfully applied in GDF Suez UGS wells. The process consists of the injection of either polymers or microgels, which adsorb strongly of the surface of the reservoir rock, thus forming a stable coating which stabilizes the reservoir around the wellbore. All products are hydrophilic and environmentally friendly. They behave as Relative Permeability Modifiers (RPM), showing minimal impact on gas flow. Due to this property, the polymers can be injected into the whole open interval in the “bullhead” mode without requiring mechanical tools for placement. The products will spontaneously invade the highest permeability layers more deeply than the other ones. As, in most cases, sand (and water) come preferentially from the high-permeability layers as well, we can expect favorable self-placement of the product in the problematic zones.

The coating of the surface of the rock is obtained by adsorption of the polymer species. Polymers macromolecules have a size of 0.3 μm, which limits the thickness of the adsorbed layer. On the other hand, microgels, whose size ranges between 0.3 and 2.0 μm, form a thicker adsorbed layer on pore walls, which can be advantageous for the application. Moreover, microgels are more stable than polymers, withstanding high shear rates, harsh reservoir conditions and temperature up to 165°C.

Since 2001, seven wells in two UGS facilities have been treated with the new technology, all being successful. Main field results can be summarized as follows.

- The treatment is efficient to reduce strongly and even stop sand production for a long period of time (at least four years).
- The treatment has a minimal impact on gas injectivity/productivity (only one well suffered from a loss in gas productivity estimated as 20%).
- A well can be treated again with positive results once first treatment efficiency becomes weaker.
- Combined Water Shut-Off/Sand Control effects can be obtained in favorable cases.
- The sand control effect is not a secondary effect of a reduction in water production, since some treated wells have not produced significant quantities of water and for many wells, the treatment did not show any significant impact on water production.

Finally, we have to point out that, although applied so far in UGS wells only, the new technology has probably a high potential in oil wells or gas wells treatments, provided some adjustments are done to fit with each specific well/reservoir conditions.

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References


