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Water Shut Off Field Experiences to Improve Hydrocarbons Recovery in Depleted Reservoirs

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خبرات حقلية في مجال إيقاف المياه لتحسين إنتاجية النفط في مكامن مستنفذة

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تستخدم الهلاميات في العالم للتحكم في إنتاج الماء في آبار الغاز والزيت لغرض تحسين إنتاجية النفط وزيادة كفاءة الدفع خلال عمليات حقن المياه لسد الطبقات ذات النفاذية العالية، أو للمحافظة على إنتاجية الآبار وذلك بالتقليل من معدل إنتاج المياه. تكمن النقطة الحساسة في معرفة ميكانيكية إنتاج المياه. وقد يكون من المهم، بعد هذه الخطوة، الأخذ في الإعتبار عن إمكانية تطبيق المزيد من الأنظمة الميكانيكية المعتمد عليها قبل التركيز على الأنظمة الكيماوية، أما بالنسبة لطريقة الأنظمة الكيماوية فهناك نقطتين أخرتين حساستين يجب أن تؤخذا في الإعتبار.

- إختيار النظام الكيماوي.
- الوضع السليم للمائع المعالج.

تعتمد الفائدة الجمة التي يمكن الحصول عليها على معرفة وضعية الحقل و/أو البئر إضافة إلى التشخيص الجيد للمشكلة. أما بالنسبة لإيقاف المياه الكيماوية فإن دعم النشاطات المعملية مهم جداً لإختيار أو تأكيد النظام المناسب وصياغته من أجل زيادة معدل نجاح العلاج نفسه.

إن مراجعة مشاكل المياه وتقنيات وضع الهلاميات إلى بدائل وطرق غير إعتيادية للإزاحة باستخدام هلاميات ومبلمرات. وتم تطبيق هذه التقنيات من أجل ستكمال إنتاج النفط من مكامن غاز طينية مستنفذة.

تم تطوير هذه التقنية الجديدة للتقليل من المصاريف ولجعلها أكثر إجتذاباً. هذا بالإضافة إلى تصميم تطبيقات معدل النفاذية النسبية لمعالجة الإكتمال الأكثر تعقيداً.

تم في هذه الورقة تقديم نبذة مختصرة للنشاطات المعملية الخاصة باختيار البوليمرات والهلاميات المناسبة وكذلك بيانات المعالجة الحقلية ونتائج العلاج بالهلاميات ومن تطبيقات معدل النفاذية النسبية.

هذه التطبيقات تم دراستها للتقليل من تكاليف معالجة الحفر وزيادة إحتياطيات هامشية من مكامن مستنفذة ومتعددة الطبقات، وبالرغم من أن العديد من النقاط المذكورة تتعامل مع آبار الغاز إلا أن تطبيقاتها على آبار الزيت يبقى ممكناً.

Abstract: *Gels are used world-wide to control water production in oil and gas wells in order to improve hydrocarbons recovery, to increase sweep efficiency during water injection by plugging high permeability layers, or to keep wells producing by reducing water production rate.*

The critical issue is the correct identification

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of water production mechanism. After this step it is important to consider whether the more reliable mechanical systems can be applied before focusing on chemical systems.

For the chemical system approach there are two more critical points to consider:

- *the selection of the chemical system;*
- *the correct placement of the treatment fluid.*

The maximum benefit that can be achieved depends on the knowledge of the status of the field and orlthe well and on a good problem diagnosis.

For chemical Water Shut Off (WSO), the support of laboratory activity is very important to select or verify the right system and formulation in order to increase the rate of success of the treatment itself.

A review of water problems and gel placement techniques has led to a study of alternative and unusual displacement methods using gels and polymers. These techniques have been applied in order to complete the hydrocarbons recovery in shaly gas depleted reservoirs.

A new bullheading technique had been developed to reduce costs and to make WSO more attractive. Moreover, Relative Permeability Modifier (RPM) applications had been designed to treat more difficult completions (dual completion, short strings, selective strings, gravel pack' completions) and thin multi-layered reservoirs.

In this paper a brief summary of laboratory activities for a correct polymers and gels selection is reported as well as field treatment data and results from bullheading gel treatment and from RPMP application.

These applications had been studied to, reduce treatment costs by rigless operations, produce marginal reservs from depleted and multi-layered reservoirs.

Many of the issues deal with gas wells applications, but they can be easily applied to oil wells.

INTRODUCTION

Water production is, very often, a big concern during the lifetime of oil and gas wells. The increase of water cut leads, sometimes very rapidly, to a dramatic increase in operating costs, resulting in uneconomical production, with the final result of premature well abandonment and loss of reserves.

WSO techniques have been developed to control problems related to water production.

The main topics that can be addressed are:

- recovery of residual reserves not conventionally producible;
- reduction of water disposal costs;
- reduction/removal of water production related problems (scale, souring, water treatment plant costs).

All these topics cause costs that reduce the economic exploitation of reserves, especially in the last part of the life of a field. As a matter of fact, the high work over costs, mainly in offshore fields and the increasing disposal costs do not allow the whole recovery of the available producible hydrocarbons.

In this context, WSO technologies have been introduced to control water production using mainly rigless operations maximizing the hydrocarbon recovery.

WSO technologies available at the moment on the market, consist of mechanical and chemical systems.

Treatments of such situations using polymer gels have been experienced during the past 15-20 years and the polyacrylamide/Cr(III)-complex technology has been recognized to be the most successful chemical technique'. However, placement of these field proven gels is very often the most difficult aspect to be addressed.

Therefore, any well candidate to WSO treatments must fall in specific categories to be treated with gels with a good chance of success. The knowledge of the correct water production mechanism, the presence of reliable separation (shale) between layers producing water and gas or oil, the certitude and possibility to place correctly (in the water producing layer) the gelling solution are only a few of the many attributes that a well must satisfy to be a "good candidate". For the "mature" gel technology, rules for chemical selection and methodologies for correct placement are, generally, well defined resulting nowadays in high success rates. In some situations, in case of a particular formation characteristics or in presence of very complex completion configurations, treatments using gels are not feasible and the "relatively new" technology that simply uses RPM polymers can be invoked and, if possible, applied.

Finally, the economics of the entire process must be re-evaluated in order to achieve a true success in the field.

The selection of candidates is made considering the following criteria:

- definition of motivations of WSO treatment;
- identification of the water production problem;
- screening of the treatable problems;
- identification of the workable solutions (mechanical or chemical);
- evaluation of results achievable;
- treatment costs.

The definition of "good candidate" is not rigid and schematic because it depends on technical feasibility, objective of treatments, regional constrains and economical evaluation which can vary during the lifetime of the field or the wells to be treated.

Often the standard techniques cannot be easily applied because of the presence of unconventional well completions or well situations.

The main concerns, that is a large part of the Italian scenario, are the following:

- sand control completions and/or screens that preclude the possibility to divert a gel/gelant system by installing inflatable packer;
- conventional wells where sand production induces the creation of cavities behind casing, precluding the use of inflatable packers.
- in single completions, usually installed in marginal fields, if tubing ID are small (in case of unloading problems in wells where once formation water starts to be produced),again, inflatable packers cannot be installed because of the to large IDcsg/ODtbg ratio.
- reservoirs are composed by different layers and each layer is usually divided into sublayers, each of them having its own aquifer. Therefore most of the wells have multiple completions in 7" casing with small tubing ID, being
- 2 2/8" tubing OD the most common. Inflatable packers cannot be run through 2 3/8" OD tubing and set against a 17" OD casing because it cannot expand that much;
- the same perforated interval can open a few sublayers to production at the same time and, in this case, it is quite impossible to recognize which sublayer is responsible for water production and, therefore, zonal isolation cannot be applied even if a suitable mechanical system could be applied to divert a gelant;
- the selective completion is difficult to treat because it is not possible to do any kind of conventional diversion for gelant system;
- dual injection without inflatable packers cannot be applied because no sensors exist which can be run through this, so small tubing ID, especially when radiotracers, cannot be used, as well as in Italy.

Moreover, reservoir simulators are not always available and only water production mechanisms due to some well bore problems could be quickly investigated. However, this analysis is very rarely accepted and performed because it too expensive, usually more expensive than the treatment itself.

The usual lack of knowledge relevant to water production mechanisms in Italian gas wells, the complexity of the reservoir lithology and bottom hole conditions, which cannot allow the use of inflatable packers, make standard gel treatments something not applicable in most of the wells. On the other hand, a solution to the problems caused by produced water had to be found in order to produce all the reserves in place.

Bullheading seemed to be the only attractive placement technique for these gas wells.

After an extensive lab activity, a very efficient and very cheap RPM polymer was selected for a field test. In 1989, gas well CA#I was shut in because of excessive water production, leaving downhole a consistent amount of gas reserves; any attempt to put this well in production was unsuccessful. In order to minimize risks associated with bullheading treatment, this well was selected as the best candidate for treatment with RPM polymers.

However, as well as known by literature and confirmed by lab experiments, the efficiency of RPM polymers adsorbed inside a porous media declines with time, because the polymer can be diluted and transported by formation water still produced after the treatment. Therefore, RPM treatments need to be re-injected in the same well to restore productivity once the polymer injected with a previous treatment has back flowed. Even if less efficient than a "true" RPM, a standard crosslinked gel can act as RPM,,once overdisplaced and saturated with gas (nitrogen). This system, once introduced inside a porous media, cannot be removed by produced water and it is supposed to be very long lasting.

Considering how difficult it is to displace uniformly any liquid phase with gas (nitrogen), a simple method for treating gas wells with gel was selected. However, the treatment, consisting of bullheading a plugging gelant and nitrogen, is very risky. For this reason, the gas well selected for the field test, CO# 9SL, was a very poor candidate: minor gas reserves were still in place and water production mechanism was completely unknown, even if some hypotheses were done based on production data analysis and something very similar to a water coning was recognized as the most likely.

The two candidates were similar in terms of low bottom hole temperature and pressures; both the wells produced from gas bearing zones composed by poorly consolidated, laminated sands.

CO# 9LS is also characterized by a gravel pack sand control completion.

WATER SHUT-OFF TECHNOLOGIES

The production of excess water in a gas or oil well can be originated by the presence of many different problems that can be located near the well bore or deep into the formation.

Depending on the type of problem and location, mechanical devices or chemical treatmen can be used to control unwanted water influx.

Generally speaking, the simple use of bridge plugs or packers to isolate any water-producing zones has to be preferred to solve problems which can be faced by isolating some part of the well bore; because they are cheaper and have higher rate of success. Mechanical systems include cement plugs, since this product is well known and it is used very often in conjunction with other mechanical tools.

However, if the problem cannot be corrected from inside the well bore, some chemical must be selected and pumped deep enough into the formation to fix the problem. Among chemical treatments, inorganic gels, monomeric gels,polyacrylamide based organic gels or simply polymer solutions can be selected. They are suitable for near well bore or deep treatments and must be injected into the formation at a pressure high enough to invade all the interested zone, but below formation fracturing pressure.

However, if very low permeability zones must be treated, the ability of a gelling solution to be injected without applying too high differential pressure (with the risk to exceed fracturing pressure) becomes a real concern. In these cases the use of systems having low viscosity (~ 1 cP) can guarantee the injection of the fluid deep enough (1-3 meters) to obtain good sealing capacity once the gels are developed. Inorganic silicate based formulations or monomeric ("in-situ" polymerized) systems can be the right answer for such situations.

In the last years, polymer gel systems have been considered an emerging technology that now can be regarded as a completely effective and consolidated tool. Treatments, carried out with chromium crosslinked polymer solutions, are the most widely used and, nowadays, internal know-how permits the use of these types of gels having very good control on injectivity, gelation time, propagation depth into the formation and permeability reduction.

One of the main concerns relevant to polymer-gel technology is the (correct) placement of the treatment: the fluid must be injected in the water producing zone to avoid undesirable damage of the hydrocarbon layers.

Polymer solutions have been used in the past, starting during the 1970's, as water control technology based on the ability of some polymers to reduce selectively water permeability leaving almost intact gas and oil permeability (this kind of systems are reported as Relative Permeability Modifier,(RPM)[2,4]. Many treatments were carried out considering their low cost (generally a low polymer concentration is required) and the minimal risk of damage of oil/gas producing zones. In spite of that, the success rate of these operations has been considered too low, but the majority of failures can be attributed to the lack of knowledge of polymer chemistry and to inappropriate candidate selection.

Considering the Italian situation, RPMs were selected as the most suitable system to correct water problems, but gels were not abandoned since they could have found a field of application if a safe system of placement existed. For instance, it is well known that a RPM can work up to a certain permeability, becoming ineffective above certain values, whereas a gel could work fine in this high permeability formations. However, all the studies were oriented towards bullheading treatments because any other system would have required too many details and analyses logs, survey, pressure build up, and so on) to be selected as a suitable technique to restore wells productivity in marginal fields.

Case Histories

In this section a description of the initial situation and the well production parameters will be reported, for each case.

A general picture of the results obtained during a two-years research activity on the use of RPM in low temperature gas wells together with the optimization of the formulation for the treatment in well CA# 1 and the laboratory tests carried out for the evaluation of a new placement technique for a gelling polymer solution suitable for the well CO#9SL will be discussed.

Finally, for each well, field operation and post-job evaluation data will be reported.

Bullheading an RPM Polymer. Well CA#1. CA#1 is a gas well, shut down since April 1989, after a ten months production period, because the high water cut caused the well to stop flowing. The last production parameters were Q_g = 22000 Sm^3/d, Q_w = 30 m^3/d and FTHP = 34 kg/cm^2. The well was lifted a few times with gas (nitrogen) but gas productivity was never restored and sand was produced with a tremendous amount of water.

This vertical well was work-overed in 1988 and re-completed with a single 2 3/8" , 1.995" ID, tubing in a/7" casing; an external 9 5/8" casing is olso present at perforation depth, 963-966.5 m/RT, 4 spf, E.H.: 0.35". The following layers were identified by log analysis:

- 2.3 m of gas *zone* (963.5-965.8 m/RT).
- 0.4 m of clay (965.8-966.2 m/RT).
- 1.8 m of gas zone (966.2-968.0 mJRT).

The deepest layer was intended not to be perforated, but the bottom section of perfs entered the lower gas layer by 0.3 m, 1 ft, and the lower layer resulted in being completely depleted and watered out. No surveys were run in this well and the water production mechanism was derived on the basis of logs, geologic interpretation of seismic and production data (diagnostic plots[5]).

Other data relevant to this well are as follows:

- SBHT = 48°C(118°F)
- SBHP = 69.3 kg/cm^2, 0.72 $kg/cm^2/10$ m (985 psi, 0.31 psi/ft)
- STHP = 64.0 kg/cm^2 (910 psi)
- k_{gas} = 13OmD
- k_{brine} = 44 mD, assumed 30% of k_{gas}
- Frac press: 128 kg/cm^2, 1.32 $kg/cm^2/10$ m (1820 psi, 0.57 psi/ft).

Owing to the reduced layer thickness, no applicable were found in the market. Cement was not considered a valid option because of the risk of plugging the entire perforated interval, Moreover, a void behind casing was expected because of the above mentioned and reported sand production: any sealing device inside casing would have very likely failed. Dual injection was considered at the beginning of the study, but it was found too expensive and inappropriate for this candidate. Finally, bullheading gelant followed by nitrogen overdisplacement, the already described technique, was not available at the moment this well was considered for a WSO treatment.

In this situation the well appeared to be a possible candidate inside a two-years research activity about the use of polymers as Relative Permeability Modifiers.

The research activity. As discussed earlier, the particular Italian situation pushed strongly the EN1-Agip R and D group to the evaluation of new systems capable to control water production in wells where bullheading is the only possible option for placement.

A literature survey highlighted the use, in many previous applications, of a "trial and error" approach rather than a well defined selection grid of well candidates and chemicals. For this reason one of the main targets was to define a series of rules to correctly choose a "good candidate" and the proper chemical agent". The execution of a field test to verify the results, obtained during the research activity was the final goal.

General results. A series of indications have been obtained from the laboratory activities and are fully reported elsewhere [6-9]. In this contest, the main subjects that have been investigated can be pointed out as:

- polymer-rock interactions;
- formation lithology;
- effects on relative permeability.
- injectivity.

The polymer-rock interactions have been investigated studying the adsorption isotherm and the kinetic of this process for more than 14 commercial polymers which were different in electric charge (cationic, anionic and non-ionic), in chemical nature (biopolymer, synthetic polymers co- and ter-polymers) and in molecular weight (2*105– 2* 10^7 Dalton).

Having already in mind the application on the well CA#l, these tests were carried out on a specific sand coming from an offset well drilled in the same area. The mineralogical content of this material is presented in Table 1.

Table 1. Modal content of sandstones (vol.%).

Quartz	49	Smectite	20
K-feldspar	17	Mixed layers	0
Plagioclase	9	Illite	29
Calcite	21	Kaolinite	21
Dolomite	0	chlorite	30
Shale	4		

The adsorption tests permitted a first screening of the collected polymers that have been classified with regard to their ability to adsorb onto the sand. In this way, polymers with "high affinity" to the rock (adsorption from 1-4 mg of polymer/g of sand) and with "low affinity" (below 1 mg/g) were identified. The majority of cationic and some non ionic polymers in the first category, fall while some non ionic and all the anionic polymers fall in the second one.

The adsorption tests were carried out using diluted polymer solutions, generally 1000, 2000 and 4000 ppm, that have been also characterized from the rheological point of view. The rheological behavior in the range of shear rate (1-1000 s^{-1}) and temperature (25-50 °C) investigated is typical of a lightly non-Newtonian fluid with low viscosities ranging from 2 to 5° CP.

The kinetic response of the adsorption tests quantified in about 24 hours the time needed to reach the "plateau" region in the isotherm adsorption curves. In addition, the "plateau" in the curves "adsorption *vs.* concentration" clearly indicated the optimal concentration of 2000 ppm for the polymer treating solutions.

Following these initial tests, three polymers (two cationic, one weakly anionic: some information are reported in Table 2) were selected to further investigate their performances in core flow tests. Sandpacks, obtained using the reference sand, were treated following the procedure reported [8]. Initial absolute brine permeability of about 250-400 mD have been observed in a first series of samples, while, following a more accurate procedure for samples preparation, values of 60-100 mD have been obtained. In Table 3 some results are reported and the good water permeabi1ity reduction is quite

evident especially using the two cationic polymers, while the gas permeability is only slightly affected. it is important to point out that these results are in good agreement with the adsorption test that gave, for the cationic, higher affinity to the formation sand. Between the two (roughly) equivalent cationic polymers we choose "CAT-1" because it is readily available on the market and all the subsequent tests were performed using this polymer.

In Table 4 additional data, obtained with the goal of deeply investigating the performance of the chosen polymer, are reported. In this Table, test # 2 and # 3 were performed using a "shear degraded" polymer solution. In fact, it is reasonable to imagine that the polymer can be subjected to a mechanical degradation because of the high shear rate reached during the injection in the porous media, especially in the region around perforation tunnels. So, to verify the effectiveness of the polymer solution after such degradation, the mentioned tests have been carried out using a CAT-1 solution (2000 ppm) previously pumped through a sand pack at an injection rate of about 0.6 m/min. Measurements of "Total Organic Carbon" (TOC) content have shown the same amount of polymer before and after the "shear degradation"; so the observed reduction in viscosity, from about 4 to about 2 cP (at 25 °C), was totally due to the polymer chain degradation. The results reported show the equivalence, in terms of k_{gas}, and k_{brine}, reduction,

Table 2. Polymers used in core tests.

Polymer	Structure	Ionic charge	Molecular weight (Dalton)
HPAM	Hydrolyzed Polyacrylamid (D.H. 1%)	Weakly anionic	5 million
CAT-1	Cationic polyacrylamid	Cationic	1-2 million
CAT-2	Cationic polyacrylamid	Cationic	7-800,000

Table 3. Permeability reductions in core flow tests.

Polymer	Initial absolute k_{brine} MD	Äk/ k_{brine}, %	Äk/k_{gas}, %
CAT – 1	413	86	8
CAT – 1	270	81	25
CAT – 1	24	81	49
HPAM	170	65	30
CAT – 2	58	82	53
CAT – 2	86	77	56

Table 4. Permeability reductions with CAT-1.

Test number	Initial absolute	Before treatment		After treatment		Äk/k_{gas}, %	Äk/k_{brine}, %
	k_{brine}, mD	k_{gas}, mD	k_{brine}, mD	k_{gas}, mD	k_{brine}, mD		
1	247	690	198	527	35	24	82
2*	15	70	15	50	2	29	87
3*	474	1200	284	1198	205	0	28

between the "sheared" and "unsheared" solutions, if the initial absolute permeability is lower than 300 mD (test 1 and 2), while for higher values a decrease in the performance can be observed (test 3).

During the laboratory injection tests, using the chosen CAT-1 polymer solution (at 2000 ppm), some anomalies were observed with regard to the decrease in injectivity. In fact, it was evident that the CAT-1 fluid, when it moves inside the porous media, had a viscosity "apparently" much more higher than the viscosity measured by rheometers. During pumping, the observed pressure increase, is in the order of ten fold higher than the expected value determined on the purely effective viscosity difference between brine and polymer solution. This was attributed to the first step in the adsorption process that clearly changes the brine permeability and needs higher ÄP to continue the polymer injection. These effects are shown (Fig. 1) , where the profiles "injection pressure *vs.* time" for three different concentrations of CAT-1 are reported. Based on these evidences and on the adsorption data mentioned before, a final concentration of 1500 ppm was chosen for the field application.

Field application. The first step of the programme was tubing cleaning. After killing with 3% KCL brine, a 1¼" OD coiled tubing allowed completion fluid to be circulated for cleaning; acid pills were planned to complete this step considering cleaning quite critical in any injection treatment. After more than three times well bore volume pumped down hole and no fluid returned at surface, it was clear that formation injectivity was extremely high, much higher than expected. In order to reduce injectivity, achieving a circulating condition, the same fluid selected for the treatment was pumped down hole in an effort to reduce water permeability, and therefore injectivity, making circulation finally possible.

20 m^3 (*125* bbl) of CAT-1, 1500 ppm in 3% KCl brine, were prepared and pumped via CT at 1.4 bpm (+40% injection rate, compared to 3% KCl base brine; CAT-1 acted as a friction reducer, (Fig. 2) and 0.4 bpm of return were obtained just at the end of pumping. A clean fluid was obtained after 0.92 m^3 (5.8 bbl) of fluid recovered at surface; return line was closed at this point and all the pumped fluid injected.

A huge cavern (estimated volume 8 m^3, 50 bbl) was present behind casing and it was responsible for the very high injectivity encountered.

CT unit was retrieved and *35* m^3 (220 bbl) of CAT-1 were bullheaded trying to maintain a constant injection rate, 0.75 bpm, 119 l/min,, for the last 20 m^3 (125 bbl), (Fig. 3). All the treatment was injected in matrix condition (invasion depth 3.4m) without any evident plugging phenomenon and the small pump available for pumping the treatment at very low rate (2 to *5* l/mm, 0.01-0.06 bpm) was not used. This pump was installed because a tremendous decrease in injectivity was anticipated, according to lab experiments and results; in fact, in standard situations where no voids are present behind casing, very low injection rates have to be addressed.

The injected treatment was finally overdisplaced to gas (nitrogen) for two reasons:

- to push deeper into the formation the excess of polymer which cannot be adsorbed by the already saturated rock surfaces in the near well bore area;
- to prepare the well for clean up.

6654 Nm^3 (235 kscf) of nitrogen were pumped down hole for a complete overdisplacement (Fig. 4) and the well was shut in for 24 hours to allow the

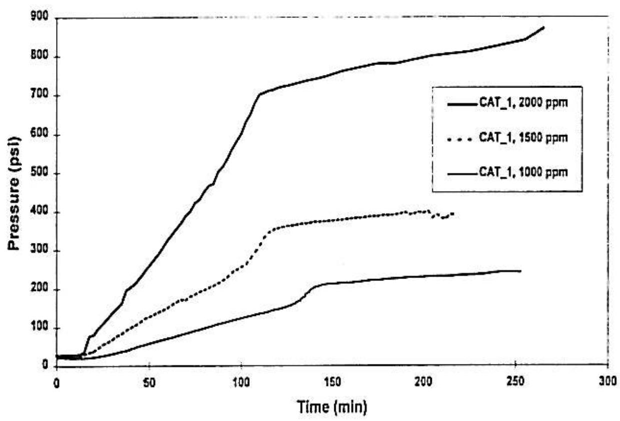

Fig. 1. Injection curves using CAT-1 solutions at different concentrations.

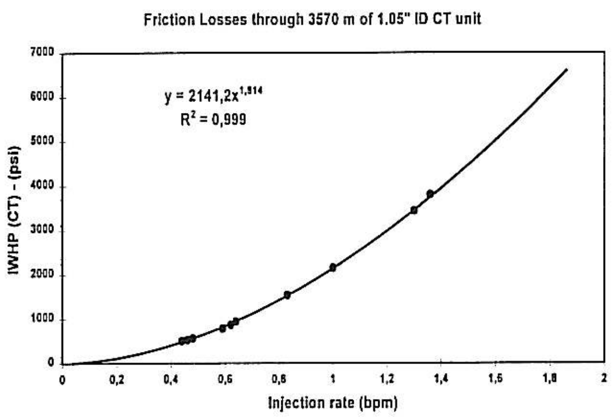

Fig. 2. Friction losses with CAT-1 palymer (well CA # 1).

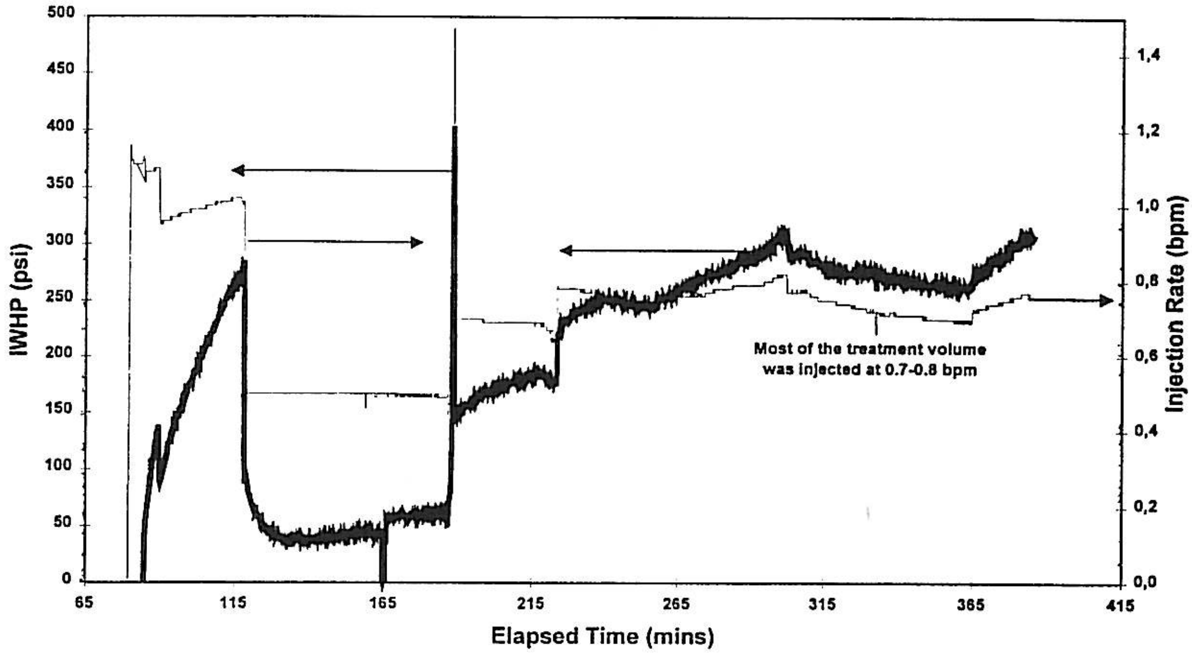

Fig. 3. Bullheading RPM Poleymer treatment (well CA # 1).

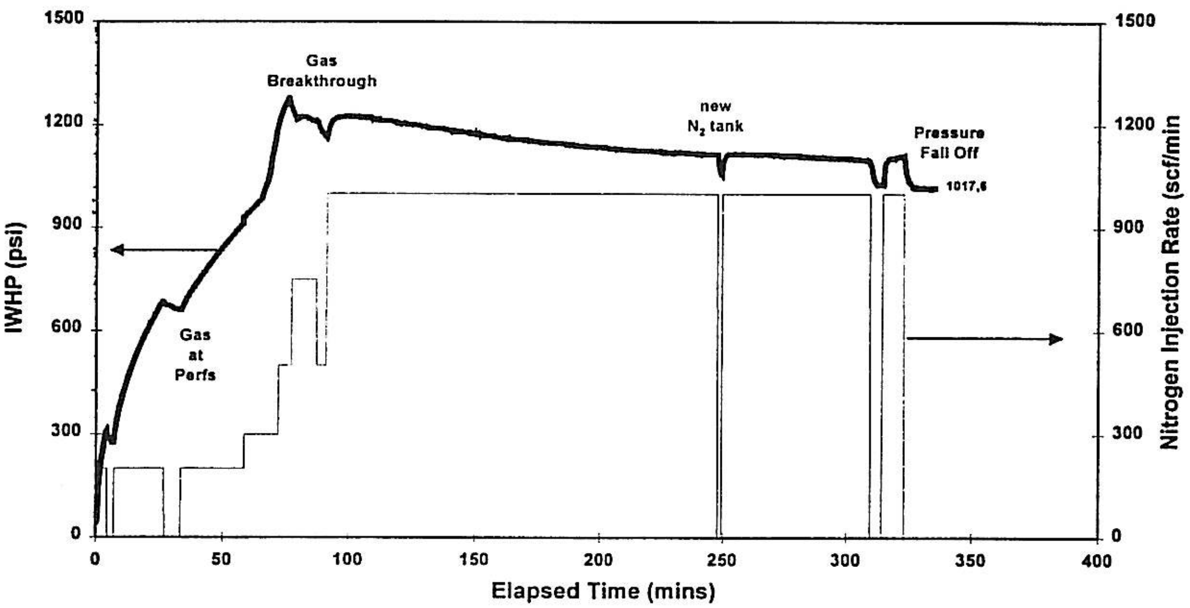

Fig. 4. Overdisplacment of CAT-1 with nitrogen (well CA # 1).

polymer to be almost completely adsored by rock surfaces (invasion depth 4.5 m).

During the beginning of the well clean up (Fig. 5), nitrogen, some hydrocarbons and no water were produced, However,after two weeks, the production stabilized to the following parameters:

Q_g = 31000 Sm^3/d, Q_w = 6 m^3/d and FTHP = 34.7 kg/cm^2.

The production parameter reached even higher values: Q_g = 37000 Sm^3/d, Q_w = 4.5 m^3/d and FTHP=51 kg/cm^2, but the risk to produce sand was very high, therefore it was decided to maintain the well at constant flow rate between 20—25000 Sm^3/d to control sand production and loading problems (Fig. 6).

The increasing water production could be attributed to the release of polymer from formation and to the increasing draw down applied to produce the well at a flow rate higher than 20000 Sm^3/d.

After the treatment, fluids, back-produced from the well, were collected on a regular basis and analyzed. During the clean up phase, the sampling was very frequent, while afterwards the production stabilization, samples were collected every two days.

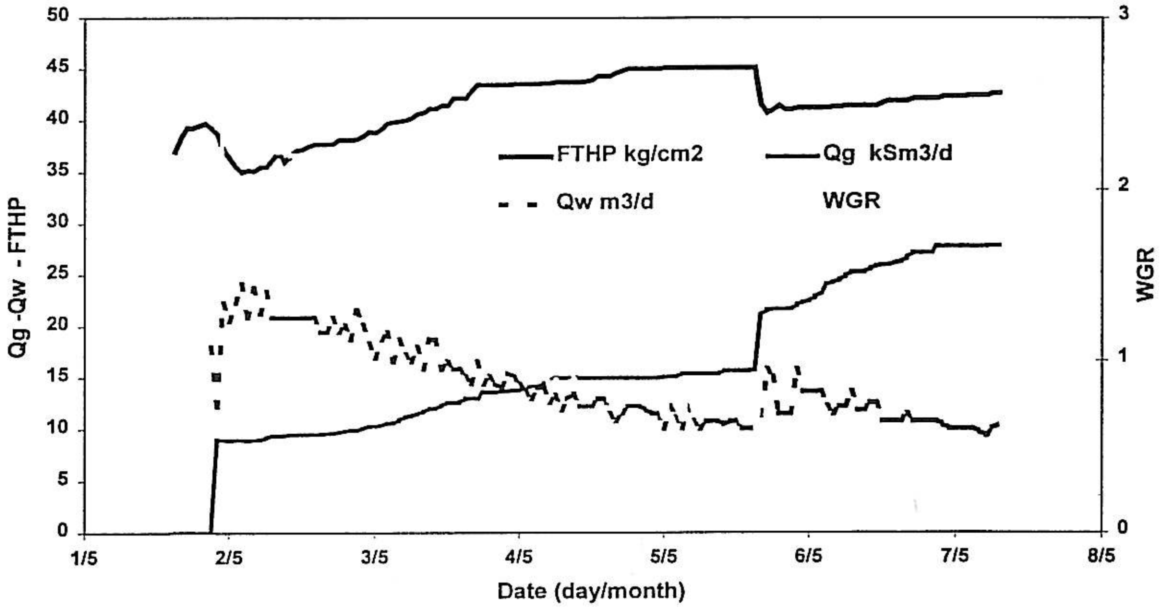

Fig. 5. Production parameters during the clean up phase (well CA # 1).

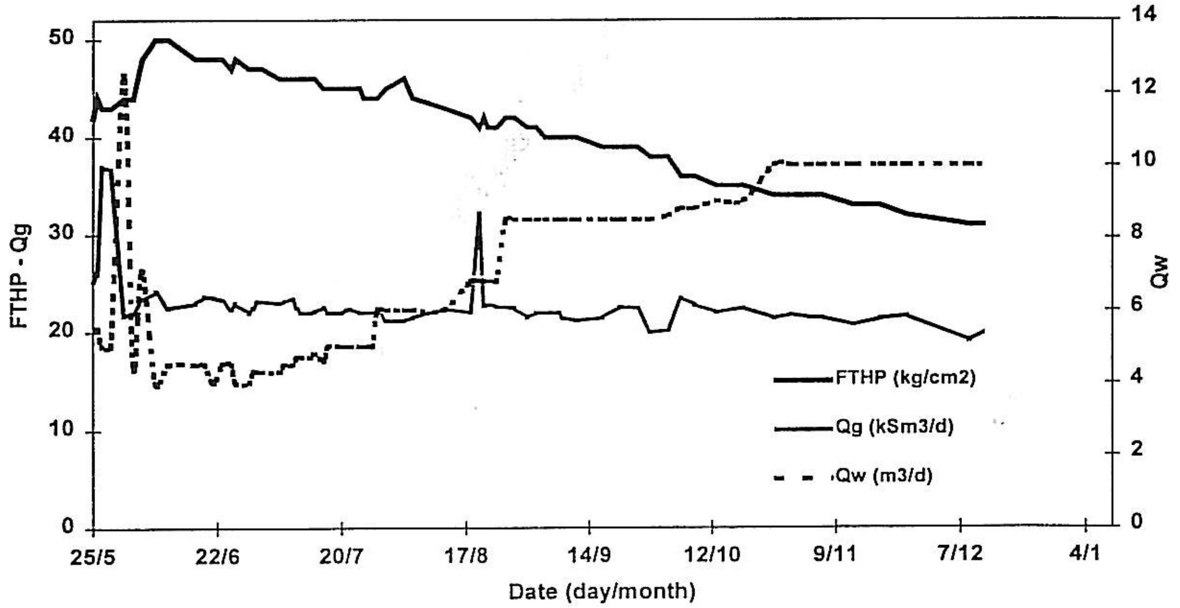

Fig. 6. Production data after the RPM treatment (well CA # 1).

In figure 7 are reported the polymer concentration in the water samples (in terms of ppm of polymer as obtained from TOC analysis) and the amount of CAT-1 still adsorbed onto the formation (considering the total amount of CAT-1 injected, 90 kg) as a function of time.

In the clean up and first production phase, ,the quantity of, polymer released from the formation, was quite high according to the hypothesis that some polymer remained not adsorbed during the shut in period (24 h). After the initial behavior (about 25 days), the polymer produced back stabilized, in terms of absolute concentration, at values of about 50 ppm. On the contrary, in the "adsorbed CAT-1" curve, it is possible to identify a continues decrease in the polymer still present in the well because of the contemporaneous increase in water production (Fig. 6).

Finally, from the economical point of view, it must be noted that the pay-back time for this first treatment has been estimated at two months.

Bullheading a Gelant (PHPA/Cr^{+3} system). Well CO#9SL.

CO#9SL is a vertical well,completed with two 2 3/8" OD, 1.995" ID, strings in 6 5/8" OD, 5.92" ID, casing; minimum restriction: landing nipple 1.875 at

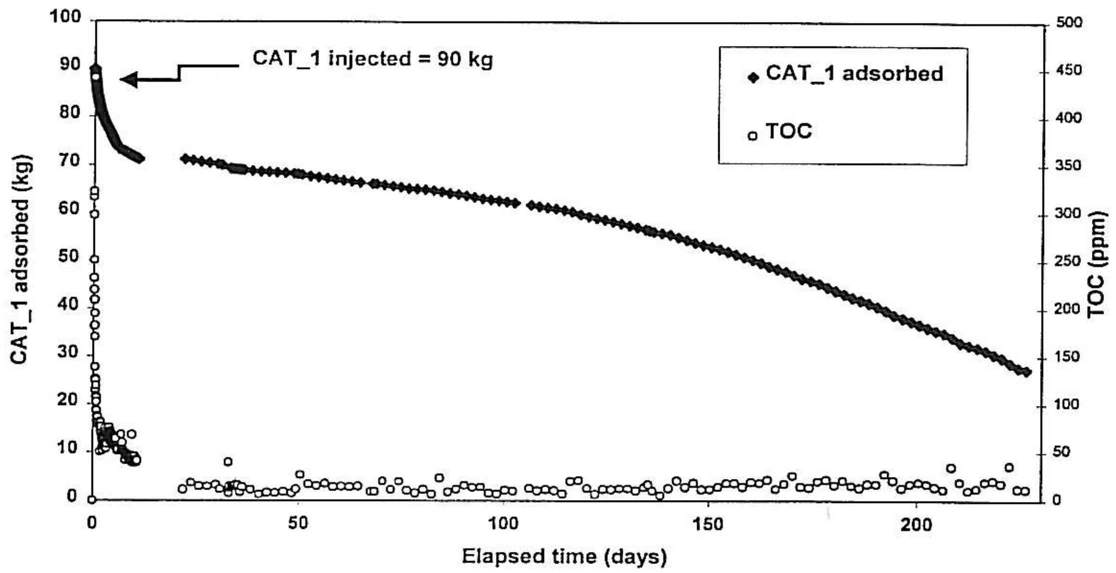

Fig. 7. Polymer adsorption analysis during production days (well CA # 1).

1061 m/RT. The long string was producing dry gas (methane) from two sets of perforations: 1120-1123.5 m/RT and 1127-1136 m/RI. ICGP was installed at the beginning of the life of the well using the high-density technique, very popular at that time, and some damage was expected to be present into the formation due to the polymers (mainly HEC) used to viscosify brines for gravel placement.

The well produced gas for years from this multi-layered zone, which is considered a compartment of a very old, well known Italian gas field located in the North of Italy.

Water started to be produced and gas production continued until the WC was so high the well stopped flowing (last production parameter $Q_g = 5000$ Sm^3/d, $Q_w = 21$ m^3/d and FTHP = 20 Kg/cm^2). Every now and then, the well was re-opened and gas started to be produced again, but the water table was too close to perforations and the well died in a few hours. A survey found formation water at 1120.5 m/RT, not above the top of perforations, and, therefore, some pay could be still at high gas saturations, ready to be produced. RST log was not run because of the cost of the log compared to the anticipated, negligible reserves still in place.

From experimental point of view this well was considered a good candidate but it was not a good candidate for any economical reasons because of the very low producible reserves still in place. However, ENI-Agip made the decision to test this novel technology, in view of future applications.

Sometimes it is necessary to inject some fluids, acids for instance, into formations and a complete coverage of the interval is always a big concern, especially in depleted zones and in long exposed intervals. Undoubtedly, gas has always been recognized as the worst displacing fluid which can be used. In fact, in order to displace a fluid, a more viscous fluid has to be used: nitrogen, instead, has a too low viscosity and should be avoided for displacement, unless used in foamed systems.

The treatment technique adopted for this well consisted in:

- injection of a gelant with a long gelling time;
- immediate overdisplacement of the gelant with nitrogen at top of perforations, leaving the whole gel at the bottom;
- shut in for gel development (days to weeks);
- clean up and production.

Some laboratory investigations were carried out using formation sands similar (in terms of permeability and porosity) to the sand to ber treated, without any effort to have a very representative sand; in fact, these tests were run just to assess gel robustness once displaced with nitrogen. Using a standard formulation, 3.5% PHPA + 900 ppm Cr^{+3} with a working time of about 10-15 hours and a gelling time of about 48 hours (a composition mainly formulated considering the very low bottom hole temperature, 37 °C) more that 70% of reduction in water permeability was detected with an increase in gas permeability.

These results were considered positive and the target of the treatment was therefore anticipated as:

- leave the whole gel at the bottom of the completion, trying to plug the IGCP in front of the deepest set of perforations;
- leave just some residuat gel at the top of the completion, allowing any residual gas reserve

to be produced at surface through a system having an encouraging disproportionate permeability behavior.

For treatment design, the following parameters were considered:

- perforations: 1120-1123, 1127-1136 m/RT; 12 spf, E.H.: 0.5"
- SBHT = 37°C (98.6°F)
- SBHT = 103 kg/cm², 0.92 kg/cm²/10 m (1465 psi, 0.40 psi/ft)
- SBHT = 95.8 kg/cm² (1363 psi)
- K_{gas} = 300 mD
- K_{gas} = 100 mD, assumed 30% of k_{gas}
- Frac press.: 164 kg/cm², 1.46 kg/cm²/10 m 92335 PSI, 0.64 PSI/FT0.

The only important assumption made while planning the test was that the permeability of the interval was considered constant along perforation. Fortunately, field results confirmed this hypothesis, obtaining excellent productivity for this poor candidate.

At wellsite, a Step Rate Test (SRT) was performed to determine formation fracturing pressure/gradient and , therefore, the pressure limits for the gel injection to e later performed in matrix conditions. Gas (nitrogen) injectivity was also determined in order to have reference points for final evaluations; just a couple of meters of perforations were found free to accept gas, being the lowermost perfs completely watered out.

Gelant, 50 m³ (314 bbl), was injected at constant flow rate, 0.58 bpm, 92 1/min, in about 9 hours (Fig. 8); the maximum allowable wellhead pressure, 53 Kg/cm², 754 psi, was never achieved and the gelant was consequently injected in matrix conditions reaching an invasion depth of about 2 m. The Hall's plot showed a regular trend (Fig. 9), only disturbed

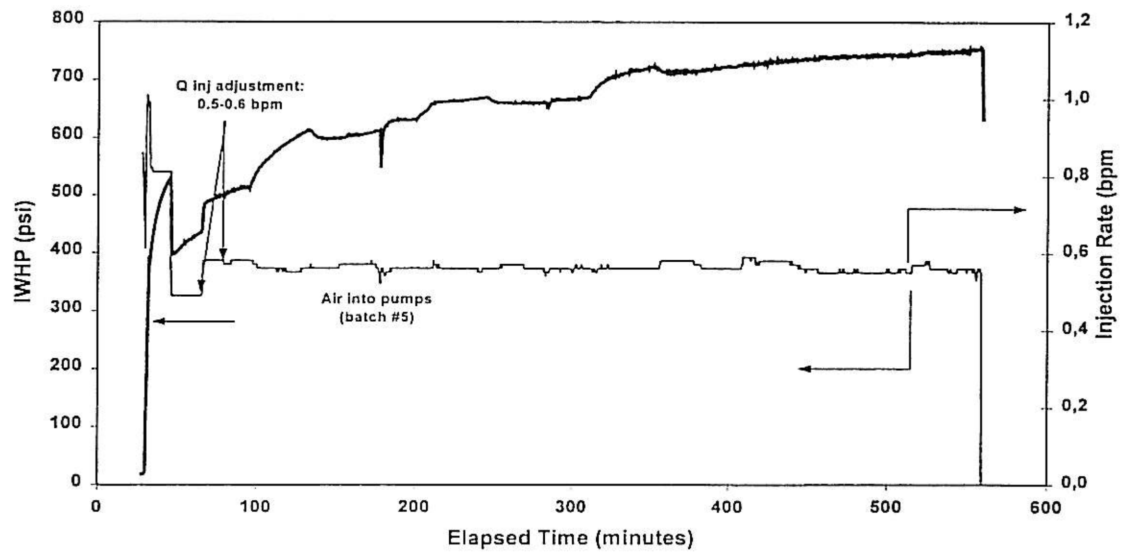

Fig. 8. Gelant injection at constant flow rate (well CO # 9 SL).

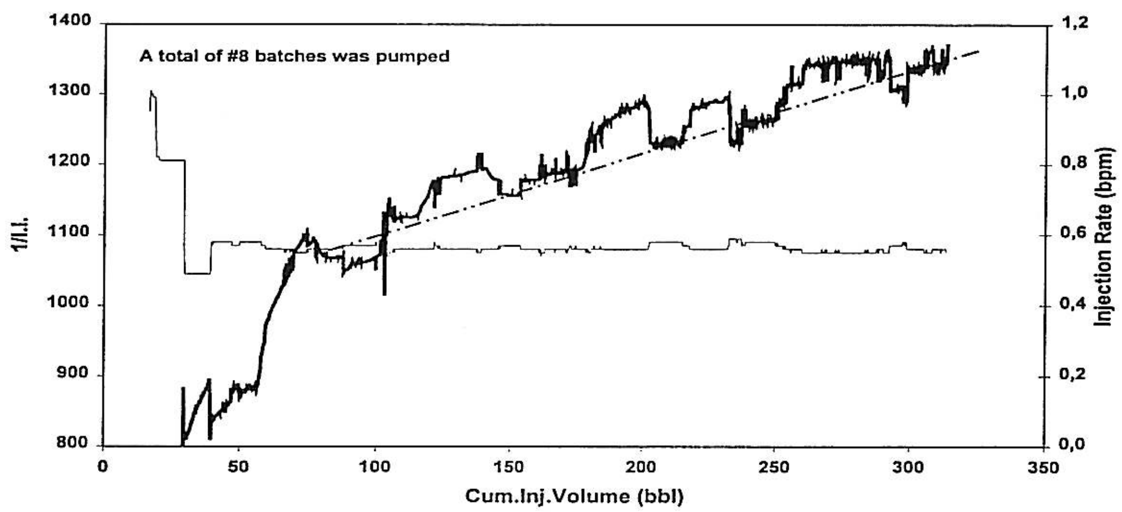

Fig. 9. Hall's plot for the gelant injection phose (well CO # 9).

by some unwanted changes in gel composition caused by the mixing system carried on the field by the service Company.

Gelant was carefully displaced with nitrogen from tubulars avoiding fracturing and, once gas breakthrough was observed through the viscous, not yet gelled, fluid bank around the well bore (Fig. 10), gas was injected at different flow rates trying to determine how much of the initial interval was exposed to flow (Fig. 11). A total of 6229 Sm^2 (220 kscf), of nitrogen was pumped for this stage.

About 1.5 m of pay (top of perforations) were found open to flow and, therefore, the entire zone below was completely invaded by the whole gelant.

The well was shut in for 2 days to allow gel to be formed. When the well was opened it produced spontaneously with the following parameters:

$Qg = 17000\ Sm^3/d$ and $Qw = 0.2\ m^3/d$ with FTHP $= 60\ kg/cm^2$. After 2 weeks the production stabilized at $Qg = 10000\ Sm^3/d$, $Qw = 3\ m^3/d$.

Owing to the small amount of the reserves the gas production declined continuously down to 5000 Sm^3/d but with a constant WGR (Fig. 12).

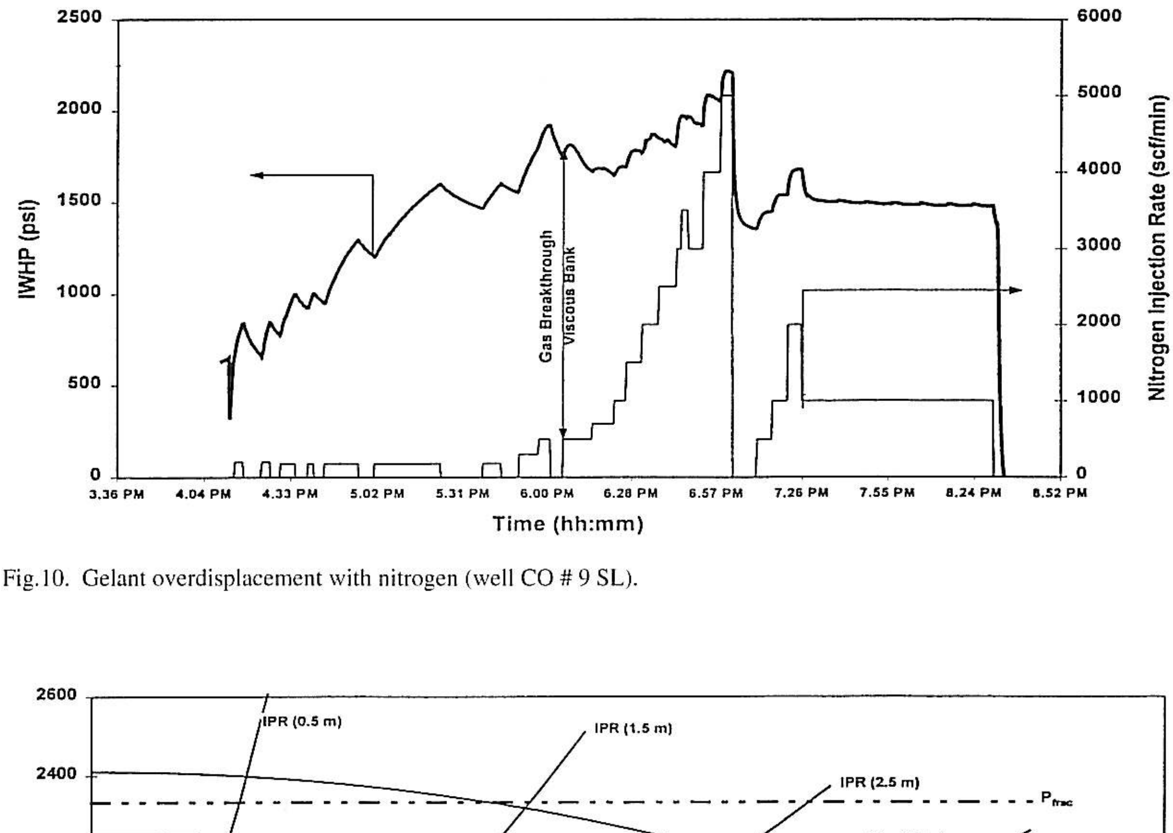

Fig. 10. Gelant overdisplacement with nitrogen (well CO # 9 SL).

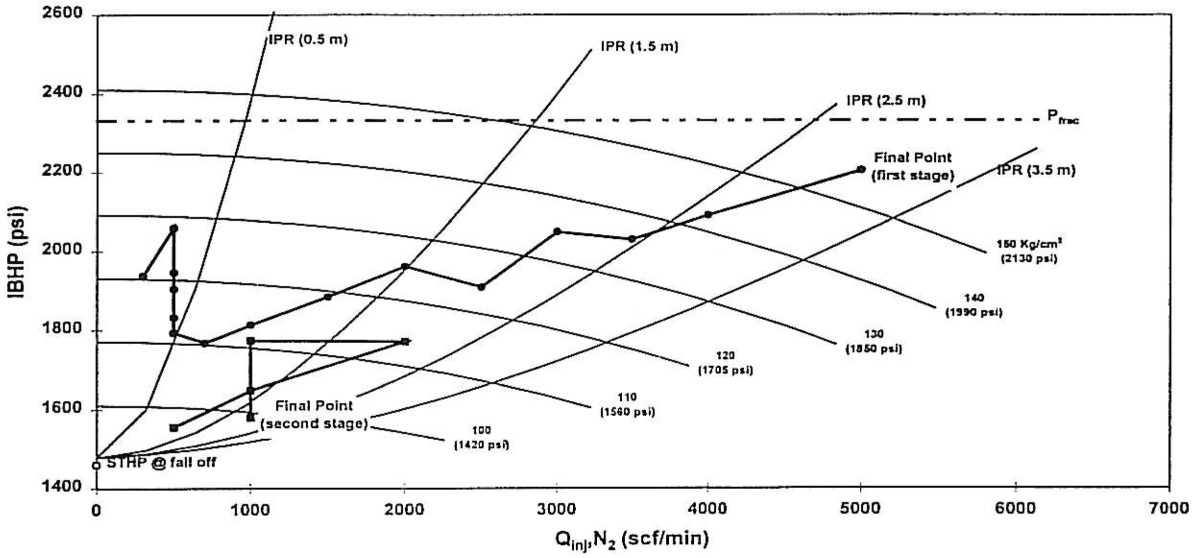

Fig. 11. Monitoring of gelant displacement (well CO # 9 SL).

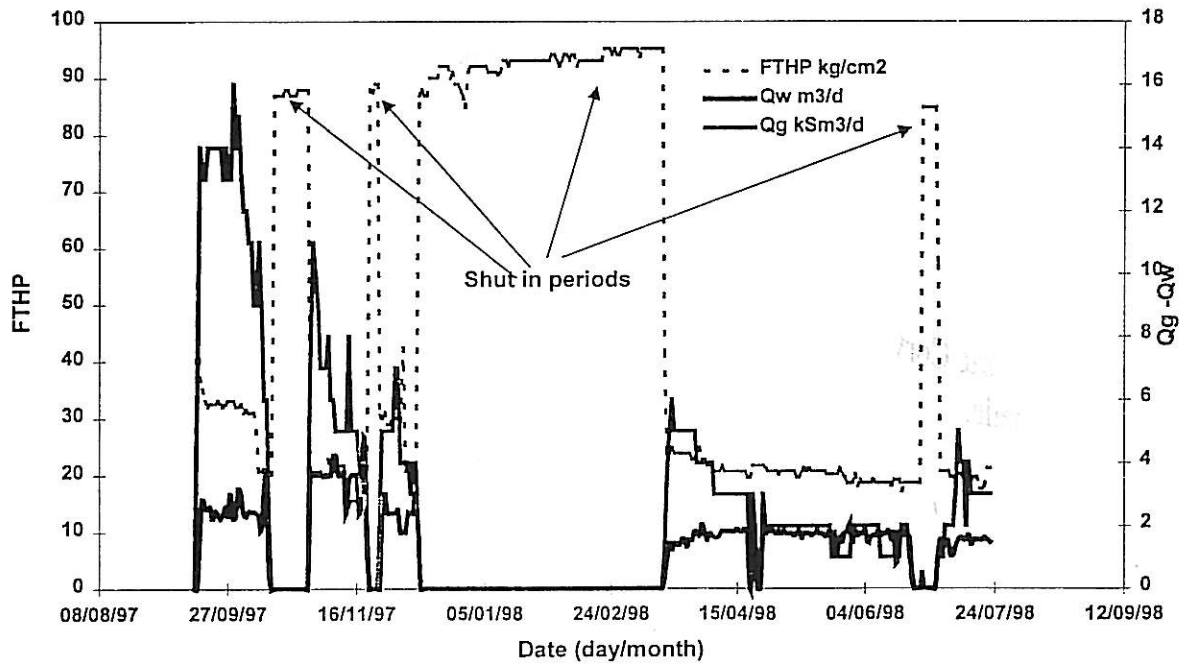

Fig. 12. Production data after treatment (well CO # 9 SL). The well was shut in four times during production.

CONCLUSIONS

The need to produce marginal reserves in depleted reservoirs and to reduce the relevant costs originated by water production and water disposal pushed Eni-Agip Division towards the development of "new methodologies" to make attractive the applications of WSO treatments.

The R&D activities developed during the last years permitted:

- the identification and codification of a series of rules to identify the good candidate and the appropriate chemical for RPM treatments in gas, multilayered and low temperature wells in sand formations;
- the first application of these rules to a field test on well CA#1. This test resulted an economical and technical success. In fact, the well was put again in production with a pay-back time of two months;
- the application of the new bullheading placement technology for a standard gelant solution in well CO#9SL. The confirmations of the possibility to treat in such way this kind of wells can be regarded as a technical success;
- a key of the success is a good candidate selection;
- maximum economic gain can be achieved in oil wells.

Further studies are in progress to exted the knowledge regarding the RPM treatments at higher temperatures and/or in oil wells.

Further applications of the two techniques are already scheduled in others Italian fields.

NOMENCLATURE

WSO	=	water shut off
ID	=	internal diameter, L, in
RPM	=	relative permeability modifier
OD	=	outer diameter, L, in
ICGP	=	inside casing gravel pack
HEC	=	Hydroxy ethyl cellulose
WC	=	water cut
RST	=	reservoir saturation tool
PHPA	=	partially hydrolyzed polyacrylamide
spf	=	shot per foot
SBHT	=	static bottom hole temperature
STHP	=	static bottom hole pressure
STHP	=	static tubing head pressure
k	=	permeability, L^2, mD
TOK	=	total organic carbon
CT	=	coiled tubing
Ppm	=	part per million
Q	=	flow rate
II	=	injectivity index
FTHP	=	flowing tubing head pressure
IWHP	=	injection well head pressure

EH	=	entrance hole, L, in
SRT	=	step rate test
WGR	=	water gas ratio
RT	=	rotary table

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Thanks are also due to everyone involved, in lab and in the field, in the activities that contributed to these two successful applications. Special thanks to Luisa Chiappa, Roberto Corvi, Amando Marcotullio and Daniele Mennella.

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SI metric conversion factors

eP x 1.0*	E – 03 = Pa.s
fsi x 6.894	E + 00 = kPa
cf x 2.831	E – 02 = m^3
bbl x 1.589	E – 01 = m^3
in x 2.54*	E + 00 = cm

* Conversion factor is exact.