Petroleum Res. J. Vol. 18 (2005): P. 115–122, 9 Figs.

# Water Shutoff Polymer/Gel Treatments for Oil or Gas Production Wells

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# المعالجة باستخدام Polymer/gel لمنع دخول الماء للآبار المنتجة للزيت والغاز

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يعتمد المعهد الفرنسي للبترول طريقة منع دخول الماء على استخدام تقنية تقليل النفاذية غير المتكافئ ( DPRs ) على سبيل المثال المواد الهلامية الضعيفة والبوليمرات تقلل بانتقاء النفاذية النسبية للماء بالنسبة للنفاذية النسبية للزيت أو الغاز وهذه المنتجات تضخ لكل المنطقة المفتوحة بدون عزل وهو اختيار جذاب مقارنة بالهلاميات المستخدمة للغلق والمقترحة من قبل الشركات.

إن منتجات المعهد الفرنسي للبترول من DPRs وهي بوليمرات قابلة للذوبان في الماء والتي هي عادة ما تنتفخ أو ضعيفة الارتباط لزيادة انخفاض النفاذية للماء دون إفساد أو إتلاف لنفاذية الزيت أو الغاز وهذه الكيماويات اختيرت لكي تكون ذات ضرر قليل جدا على البيئة ويغطي كل مزيج أو خلطة مجالا محدودا من الحرارة والملوحة.

تم تطبيق عمليات منع دخول الماء من قبل المعهد الفرنسي للبترول في مدى واسع من ظروف الآبار والمكامن وهو ما سيشهد تطورات مستقبلية عالية الاحتمال.

تصميم المعالجة يجب أن يهيأ لكل حالة خاصة حيث أنها تحتاج إلى شغل معملي لتحسين تركيبة الهلام ومحاكاة مكمنية باستخدام نموذج WSO الداخلي للتحكم في حجم الهلام وقوته. مجموعة من الحالات الحقلية الناجحة تم وصفها فيما يتعلق بآبار الغاز وآبار الزيت الثقيل الأفقية وآبار الغمر بالماء متعددة الطبقات.

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**Abstract**: *IFP water shutoff technology is based on the use of Disproportionate Permeability Reducers (DPRs), i.e. polymers or weak gels that reduce selectively the relative permeability to water with respect to the relative permeability to oil or to gas. The products are usually injected into the whole open interval, without zonal isolation, which is a very attractive option compared to plugging gels proposed by service companies. IFP DPR products are water-soluble polymers, which are either swelled or weakly cross-linked in-situ to increase permeability reduction to water, without impairing oil or gas permeability. The chemicals have been chosen to have minimal environmental impact. Each combination covers a specific domain of temperature and salinity.*

*IFP water shutoff processes have been applied in a broad range of well and reservoir conditions, thus showing a high potential for future developments. Treatment design has to be adapted to each specific case. It requires both laboratory work to optimize gel formulation, and reservoir simulations with an in-house WSO model, to size up gel slug and gel strength. Several successful field cases are described, including gas wells, heavy-oil horizontal wells, and multi-layer water-flooded wells.*

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## INTRODUCTION

Excessive water production is often due to water channeling in the part of the reservoir surrounding the well-bore, making oil production inefficient and sometimes uneconomical. Figure 1 shows a typical case, *i.e.* a two-layer reservoir well with a strong permeability contrast (for example 1 to 10), and a horizontal barrier which prevents cross-flow. Since the high-permeability layer is swept first by water, it has a tendency to overtake the oil production from the low-permeability layer. This situation calls for a treatment which intends to decrease water influx from the high-permeability layer, thus favoring low-permeability layer production.

When the different layers are clearly separated and workover costs are acceptable, the sealing of the watered-out layer with packer, cement or strong gels, placed with mechanical tools, is the best option. Nevertheless, in practice, the operator has to face several problems like poor identification of water zones, multilayered production, unfavorable completion (gravel pack, slotted liners, *etc.*) or excessive workover costs (offshore wells, marginal wells). All these issues, plus the recent development of horizontal, multilateral, sub sea wells (where mechanical intervention is costly and risky) call for more bullhead treatments in the future. One viable technique, confirmed by numerous field successes, is the use of "Relative Permeability Modifiers" (RPMs), *i.e.*, high-molecular-weight water-soluble polymers or weak gels, which reduce selectively the relative permeability to water with respect to the relative permeability to oil or to gas (Fig. 2)[1]. These products are generally bullheaded into the existing completion without zonal isolation, which makes their use very attractive.

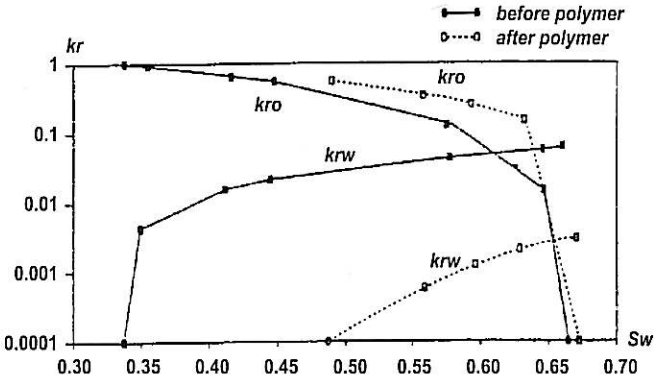



Fig. 2. Modification of relative permeability after polymer adsorption in water-wet sandstone.

Since 1980, more than 100 well treatments have been performed worldwide with IFP RPM processes. This paper describes these processes and reviews some field applications.

## IFP PROCESSES

IFP processes use non-toxic high-molecular-weight water-soluble-polymers which can be either swollen or weakly cross linked *in-situ*. Each process covers a certain domain of temperature and salinity (Fig. 3).

### Process A

Applicable in low-salinity, low-temperature matricial reservoirs, the process consists of injection of hydrolyzed polyacrylamide dissolved in a high-salinity make-up brine. After production release, low-salinity formation water replaces progressively

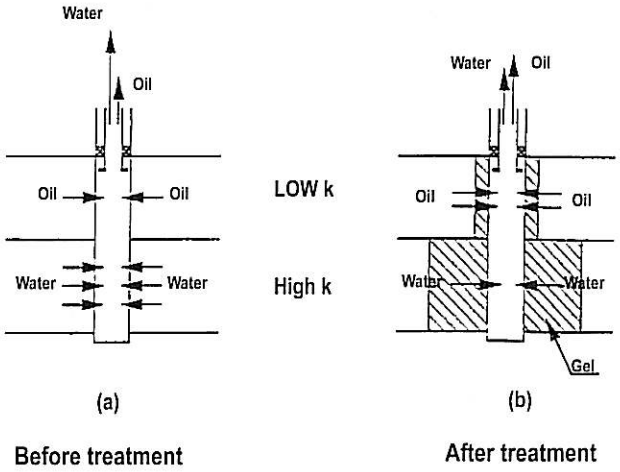



Fig. 1. Principle of RPM treatment.

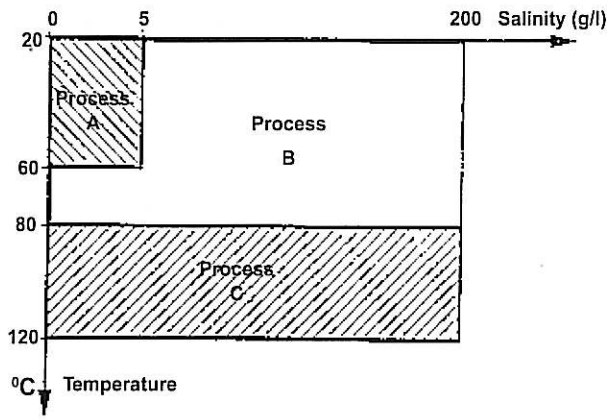



Fig. 3. Domains of application of IFP processes.

injection brine and swells the polymer adsorbed on pore walls. Advantages of this process are a low viscosity during injection, a high level of polymer adsorption on reservoir rock and a high permeability reduction to water. Moreover, the use of single polymer instead of gel reduces the risk of well impairment. For more details the reader is referred to Zaitoun, *et al.*, 1991[2].

### Process B

It consists of nonionic polyacrylamide injection with either a caustic swelling agent (that hydrolyzes the polymer *in-situ*) or an organic cross-linker. For higher temperatures, acrylamide copolymers can be cross linked by zirconium lactate. A process description with different options is given.[2,3]

### Process C

Applicable in high-temperature matricial reservoirs, the process uses scleroglucan, a polysaccharide with strong shear-thinning rheology and excellent thermal stability. Polymer swelling can be simply obtained by the release of shear forces between high injection rate and low production rate. The polymer can be weakly cross linked by zirconium lactate. Process description is given. [4,5]

## METHODOLOGY

The preparation of a RPM water shutoff treatment requires a laboratory study and numerical simulations (for example with the specific reservoir software designed by IFP, namely, ATHOS).

The laboratory study aims at (1) optimizing chemical formulations, and (2) determining input data for the simulations (polymer adsorption and end point relative permeabilities before and after polymer treatment).

Numerical simulations are run in three phases, *i.e.* (1) establishment of a history match of candidate well fluid production with a simplified near-wellbore reservoir description, (2) simulation of polymer or polymer/cross-linker injection, (3) post-treatment production forecasts. Numerical simulations aim at sizing treatment slug volume, optimizing polymer characteristics and (or) gel strength, and evaluating after treatment expected performances.

## FIELD CASES

Different field cases are discussed here below.

### 1) Gas Storage Wells: Treatments of Sandstone and Limestone Reservoirs (France)

Several water shut-off treatments on gas storage wells in sandstone reservoirs have been performed. Well treatments based on RPM technology have proven to be effective in most cases.[2,6]

For example the treatment of well VA 48 of the Cerville-Velaine Gaz-de-France gas storage reservoir by Process A reduced the water/gas ratio for at least 3 years. The main characteristics of the well treatment are shown in Table 1. The treatment is documented.[2]

Another Gaz-de-France candidate well from Saint-Clair-sur-Epte gas storage limestone reservoir was proposed for a polymer treatment. The formation consists of a superposition of alternating high-permeability grainstone layers ($k = 0.7\ \mu m^2$) and low-permeability packstone layers ($k = 0.01\ \mu m^2$) (Table 1). Due to the higher formation brine salinity, Process B was chosen, combining polyacrylamide (polymer) and KOH (activator). It was concluded from numerical simulations and laboratory tests that the optimal RPM slug volume was 200 $m^3$ and that injection had to be done in the zone below a formation packer located in the middle of the pay-zone.

Unexpected compatibility problems between the bactericide and the swelling agent induced a premature cross-linking of a part of the polymer in both surface installations and in the wellbore. Polymer

**Table 1. Treatments of gas storage wells.**

| Characteristics | Sandstone reservoir VA 48 | Limestone reservoir VN 21 |
|---|---|---|
| *Reservoir parameters* | | |
| Lithology | Massive sandstone | Layered limestone |
| Thickness (m) | 60 | 28 |
| Permeability ($\mu m^2$) | 0.1-1 (top 55 m)<br>≥ 5 (bottom 5 m) | grainstones: 0.7<br>packstones: 0.01 |
| Brine salinity (g/L TDS) | 0.972 | 14 |
| Temperature (°C) | 30 | 36 |
| *Treatment* | | |
| RPM process | Process A<br>(HPAM + salinity gradient) | Process B<br>(PAM + KOH) |
| Polymer concentration (ppm) | 3000 | 2000 |
| Brine salinity (g/L TDS) | 8.2 | river water |
| Injected volume ($m^3$) | 700 | 200 |
| *Results* | Water/gas ratio ↓<br>Water production strongly reduced<br>Gas injection/production unchanged | Gas productivity improved<br>Water production rate divided by 3 |

injection was nevertheless continued without swelling agent but with a reduced injection rate and followed by fresh water post flush.

After two years, where no significant reduction of water production was observed, the well started to behave much better and maintained these good performances for more than ten years (Fig. 4). Today, water annual production is 1/3 of the value before treatment, and, concerning gas productivity, the well, which was one of the worst in the storage, became one of the best. The delay in well response to the treatment is not well understood yet. It may be due to make-up water back up production.[7]

## 2) Horizontal Wells: Treatments in Pelican Lake and South Winter Fields (Western Canada)

Four heavy-oil horizontal wells from Pelican Lake field, namely wells 11-15A, 11-15B, 14-10A and 14-10B, were treated by Process B (Table 2).[8] Although the same injection procedure was applied, *i.e.* bullheading the chemicals into the

**Table 2. Horizontal well treatments in Pelican Lake and South Winter.**

| *Characteristics* | *Pelican Lake* | *South Winter* |
|---|---|---|
| *Reservoir Parameters* | | |
| Horizontal length (m) | 500 | 800 |
| Lithology | Wabiskaw sand | Dina sand |
| Permeability range ($\mu m^2$) | > 1 | 3 – 5 |
| Aquifer | very weak | very strong |
| Oil viscosity (mPa·s) | 1000 | 3000 |
| Brine salinity (g/L TDS) | 10 | 52 |
| *Treatment* | | |
| RPM process | Process B (PAM + KOH) | Process B (PAM + Glyoxal) |
| Injected volume ($m^3$) | 60 – 110 | 400 |
| Injected viscosity at 9.5 $s^{-1}$ (mPa·s) | 50 | 15 |
| *Results* | | |
| Water cut (%) | 85-90 → 50-70 ( 2 years) | 95 → 80 (2 months) |

slotted liner drainhole, only well 11-15A gave a good response. After treatment, the water cut dropped immediately from 85 to 50% and remained low afterwards (Fig. 5). For this well both an increase in oil production and a decrease in water production were observed for two years following the treatment (Fig. 6).

For the three other wells, the response to the treatment was much weaker, although positive. A possible explanation for this difference in behavior, could be the less favorable placement of the polymer.

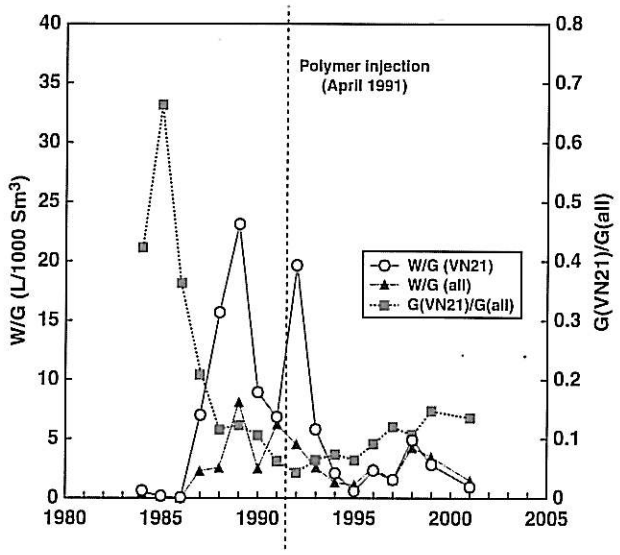



Fig. 4. Effect of polymer treatment on gas well VN-21 (Gaz-de-France, France).

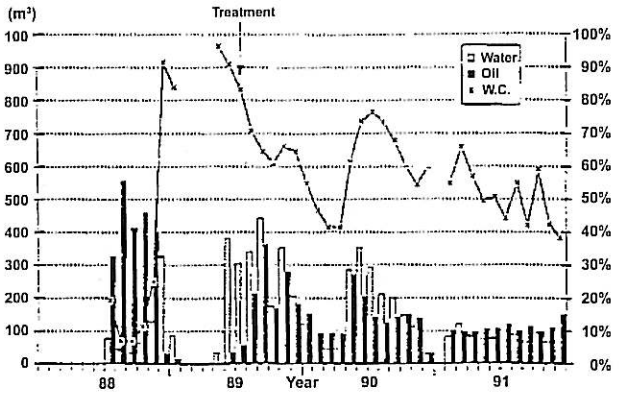



Fig. 5. Pelican Lake well 11-15A production history (CS resources, Canada).

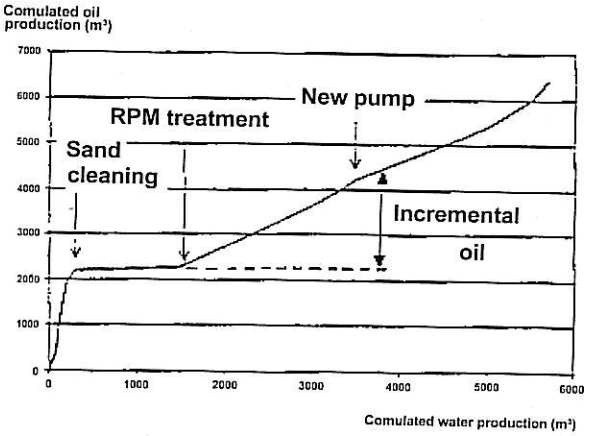



Fig 6. Pelican Lake well 11-15A cum. oil *vs.* cum. water curve (CS resources, Canada).

Indeed, horizontal well profiles (Fig. 7) show that the lowest points of the drainhole (corresponding to higher water saturation) are at the heel for well 11-15A and further away for the other wells. Probably, for these wells, an appreciable amount of polymer invaded oil

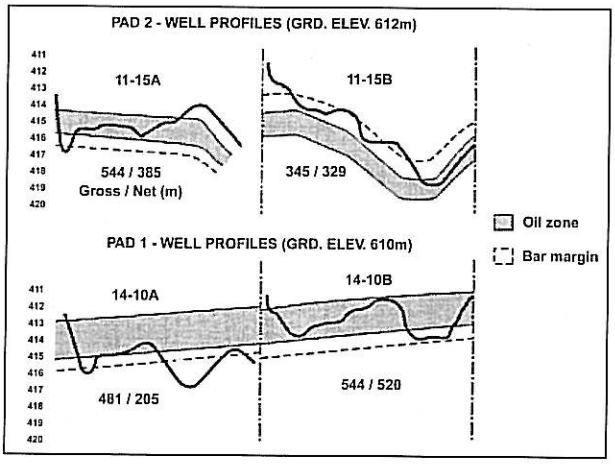



Fig 7. Pelican Lake well trajectories (CS resources, Canada).

productive zones before reaching water zones, thus making the treatment less efficient.

Another horizontal well, B 4-10 from the South Winter field, was treated by Process B. This well was producing heavy oil from a high-permeability sand reservoir lying above a very active bottom aquifer. Bottom water coning was responsible for the high water cut, rendering the production uneconomic. It was decided to perform the treatment in two steps, bullheading the first half of the injected polymer volume through a tubing placed at the heel of the horizontal slotted liner and the second half at the toe. Due to the high oil/water mobility ratio, it was estimated that the polymer would invade the water zones preferentially.

After treatment, the water cut decreased from 95 to 80% for 2 months and then slowly increased again to reach the economic productivity limit. It was concluded that polymer diversion to water zones was well achieved. However, the treatment effect did not last due to the presence of a strong bottom aquifer and a too weak gel formulation.

Table 2 summarizes the treatments of the horizontal wells in both fields.

### 3) Multilayer Water Flooded Wells: (A) Treatments in the Chagirtsk Field/Sandstone Reservoir (Russia)

A number of wells from the Chagirtsk field were treated by Process B. Candidate wells were selected on the basis of the existence of layering and permeability anisotropy. In this extensively water flooded field, Bobrick 2 (Bb 2) is the main oil producing interval. All wells are usually perforated over the total height of the sandstone reservoir. Nevertheless, some of the wells are also producing from the upper Tula 2b (Tl 2b) and Bobrick 1a (Bb 1a) intervals. Prior to polymer treatment, a water injectivity logging test was performed on each candidate well. For all wells except two, the injected water entered the Bb 2 reservoir. The exceptions were wells C 325 and C 1160, where brine injection affected respectively the top of reservoir Bb 1a and the total height of the reservoir Tl 2b (Table 3).

Process B was usually implemented in two sequences: first, a single polymer treatment aiming at diverting the gelant, then, the gelant itself, which is assumed to enter preferentially the more permeable water-bearing layers.

The size of each sequence is deduced from data such as reservoir thickness, injection rate, wellhead pressure during water injectivity test and production prior to the treatment.

Table 3 shows that for both wells C 325 and C 1160 the volume of the second sequence was much larger than for the other wells. This was done in order to reduce

**Table 3. Main characteristics of well treatments in Chagirtsk.**

| Well | Perforated interval (m) | | | | Water injectivity test | | | Treatment ($m^3$) | |
|---|---|---|---|---|---|---|---|---|---|
| | Layer | | | | | | | | |
| | Tl 2b | Bb 1a | Bb 2 | Total | Rate ($m^3$/day) | Pressure (kPa) | Intake interval | Polymer alone | Polymer + X-linker |
| C 2131 | - | - | 10 | 10 | 116 | 11 000 | Bottom Bb 2 | 50 | 42 |
| C 336 | - | - | 11 | 11 | 286 | 10 000 | Total Bb 2 | 50 | 33 |
| C 1143 | - | - | 9 | 9 | 208 | 8000 | Bottom Bb2 | 44 | 42 |
| C 1177 | 3 | 7 | 8 | 18 | 132 | 11 000 | Bottom Bb 2 | 48 | 36 |
| C 325 | 5.2 | 6.6 | 7.8 | 19.6 | 192 | 9000 | Top Bb 1a | 36 | 66 |
| C 1160 | 5 | - | 16 | 21 | 150 | 13 500 | Total Tl 2b | 25 | 67.5 |

water productivity from reservoirs Bb 1a or Tl 2b and favor production from reservoir Bb 2. Table 4 shows that this choice seemed to be erroneous for well C 325 and right for well C 1160. For well C 325 the water cut was found to increase after the treatment leading to an estimated loss of about 3,400 tons of oil over a 13-month period of time. For well C 1160, the water cut decreased drastically during the first 4 months after treatment and increased again to values close to 100%. Presumably for both wells it would have been preferable to force the treatment to enter the lower Bb 2 reservoir.

As can be seen in Table 4, the water cut in all the other wells was reduced, leading to appreciable amounts of incremental oil.

**Table 4. Main results of well treatments in Chagirtsk.**

| Well | Production data before treatment | | Production data 4 months after treatment | | Incremental oil (tons in [ x] months) |
|---|---|---|---|---|---|
| | Rate ($m^3$/day) | Water cut (%) | Rate ($m^3$/day) | Water cut (%) | |
| C 2131* | 120 | 90 | 150 | 80 | 2149 [4] |
| C 336 | 35 | 80 | 35 | 50 | 3054 [13] |
| C 1143 | 150 | 85 | 160 | 75 | 4988 [13] |
| C 1177 | 130 | 90 | 145 | 80 | 5464 [13] |
| C 325 | 160 | 90 | 190 | 100 | - 3399 [13] |
| C 1160** | 110 | 85 | 110 | 45 | 3534 [4] |

* Well C2131 was shut in after 4 months due to pump failure
** The water cut of well C1160 increased strongly to near 100 % after 4 months

## 4) Multilayer Waterflooded Wells: (B) Treatments in the Kudryachevo Field/ Limestone Reservoir (Russia)

Process B was also implemented on three wells in the Kudryachevo field producing from the Tournaisien formation (limestone reservoir). This formation is characterized by a superposition of three to seven oil producing layers more or less clearly differentiated. According to the operator the existence of large fractures in this reservoir is not proven. The formation has thus to be considered as essentially matricial with production characteristics quite similar for the three candidates.

A water injectivity logging test on these wells showed a reasonable injectivity, equally distributed over the entire height of the perforated intervals. Wellhead pressure during this test was nevertheless much lower for wells K 2 and K 9, indicating the presence of micro-fissures or high permeability streaks (Table 5). Consequently, the slug size of the polymer/cross-linker sequence for these wells was chosen to be larger than for well K 3. Actual wellhead pressure during treatments remained quite similar for all the wells (5,000 to 10,000 kPa).

**Table 5. Main characteristics of well treatments in Kudryachevo.**

| Well | Perforated interval (m) | Water injectivity test | | Treatment ($m^3$) | |
|---|---|---|---|---|---|
| | | Rate ($m^3$/day) | Pressure (kPa) | Polymer alone | Polymer + X-linker |
| K2 | 13 | 775 | 3000 | 25 | 59 |
| K3 | 24.5 | 680 | 8000 | 30 | 41 |
| K9 | 20 | 750 | 1000 | 20 | 67.9 |

Table 6 gives main treatment results. Both wells K 2 and K 9 maintained their overall productivity after treatment and had a strong reduction in water cut. On the contrary, well K 3 showed a loss in average production rate over 9 months resulting from an initial mechanical failure of the pumping equipment and an irreversible damage of formation productivity. Although the treatment of wells K 2 and K 9 produced the same amount of incremental oil, their post-treatment behavior was quite different (Figs. 8, 9). For both wells, the production rate took about 3 months to reach the level before treatment. Well K 9 showed an improvement in oil productivity during this period while the water cut of well K 2 remained high. After 3 months the opposite was observed: the water cut of well K 2 dropped sharply and remained low, while, for well K 9, it increased to pre-treatment level. The reason for this difference in behavior cannot be clearly explained.

**Table 6. Main results of well treatments in Kudryachevo.**

| Well | Production data before treatment | | Production data 6 months after treatment | | Incremental oil (tons in 9 months) |
|---|---|---|---|---|---|
| | Rate ($m^3$/day) | Water cut (%) | Rate ($m^3$/day) | Water cut (%) | |
| K2 | 110 | 90 | 110 | 50 | 6272 |
| K3 | 115 | 95 | 60 | 95 | not evaluated |
| K9 | 120 | 90 | 120 | 60 | 4772 |

## TREATMENT EVALUATION

For most operators, a successful treatment should induce both a significant reduction in water production

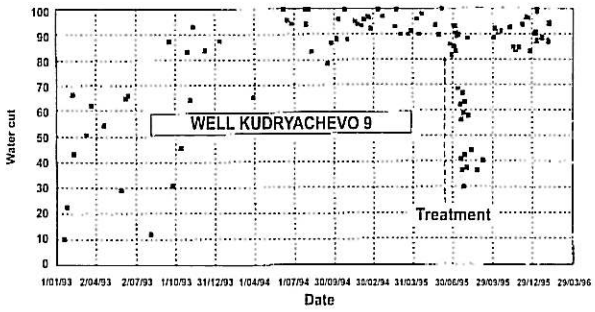



Fig 8. Water cut history of Kudryachevo well 2 (Russia).

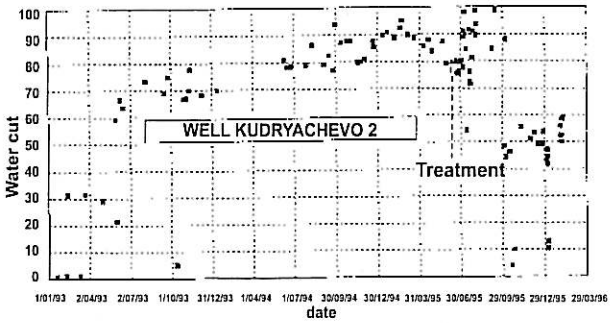



Fig 9. Water cut history of Kudryachevo well 9 (Russia).

and an increase in oil production. From the examples given above, it follows that the effect of a RPM treatment can last for several months up to several years.

A convenient tool to evaluate incremental oil production is given by plots of cumulative oil *vs.* cumulative water (Fig. 6). A successful water shutoff treatment induces a break in the plot, with a strong increase in the slope. Incremental oil can be estimated then by the difference between the actual cumulative oil curve and the extrapolated values from pre-treatment slope.[9] However, this plot does not indicate the production rate evolution, which has to be checked also to evaluate treatment success. In general, the treatment success can be measured by the pay out time, POT, and the cumulative returns vs. exceed treatment costs, PIR. In our best cases, (for example Well 11-15A in Pelican Lake), the pay-out was obtained in a couple of weeks and the return was more than ten times the treatment cost.

## CONCLUSIONS

IFP has designed several RPM water shutoff processes in order to treat various types of reservoir characteristics. They are based on adsorption of high-molecular-weight water-soluble polymers, which can be either swollen, or weakly gelled by cross-linkers. Their application domains in terms of temperature and salinity are quite complementary. IFP processes can be applied at various salinities and temperatures up to 120°C. Since the treatment can be bullheaded into the whole open interval, without need for costly workover, its economy is very attractive.

The processes have been used in quite different field situations such as (1) gas storage wells, (2)heavy-oil horizontal wells and (3) multilayer waterflooded wells both in sandstone and in limestone reservoirs. In favorable cases, the duration of a successful treatment can exceed several years.

## ACKNOWLEDGEMENTS

The authors wish to acknowledge the managements of Gaz-de-France, CS Resources and Permneft for their cooperation.

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