Petroleum Res. J. Vol. 17 (2005); P. 35–42, 11 Figs.

Development of a Bullhead RPM Water Control Treatment from Laboratory to Field

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تطوير معالجة التحكم في المياه باستخدام محورات النفاذية النسبية من المختبر الى الحقل

مايك سنقلتون وديك وير وكين سوربي وروبن شيلدز

مع تقادم وزيادة نضج الحقول النفطية في جميع أنحاء العالم هناك تركيز متزايد على الكميات الكبيرة من المياه المصاحبة لعمليات الإنتاج وكيفية إدارتها، من الناحية الاقتصادية والبيئية. وقد تكون محورات النفاذية النسبية وسيلة بسيطة وفعالة للتحكم في إنتاج المياه دون المخاطرة بإحداث إضرار بالمنطقة المنتجة للنفط. يلقى هذا الأمر أهمية خاصة بالنسبة للآبار الهامشية حيث لا يمكن للمشغل ان يبرر إنفاق جزء مهم من الميزانية على تشخيص طبيعة المشكلة تماما وذلك بسبب أن المعالجة بالسد أو عزل المنطقة غير ممكنة في هذه الحالة.

الطبيعة الإنتقائية للمعالجة بالمحورات النفاذية النسبية تسمح بإجراء أقل تشخيص ممكن ، ولكن الدرجة التي يمكن إنقاص إنتاج المياه عندها لن تكون بذلك القدر من الأهمية كمثيلتها في المعالجة بالسد. من ناحية اخرى أثبت دراسات المحاكاة، تحت ظروف معينة ، أن تطبيق معالجات النفاذية النسبية لرأس السحب في المنطقة المنتجة (5- 10 قدم) قد تؤدي ليس فقط الى إنقاص حجم المياه المنتجة ولكن أيضا الى زيادة في إنتاج النفط.

تصف هذه الورقة مجال معالجات محورات النفاذية النسبية والمنهجية التى تتبعها شركة بيكر بترولايت في إختيار وتصميم وتقييم التطبيقات الحقلية الجوهرية ، ويتضمن هذا تقييم مختبري لتأثير المعالجة بمحورات النفاذية النسبية على قطعة نموذجية من لب الممكن وتقييم هذا الناتج المختبري علي البئر موضع البحث باستخدام نمذجة تصميمية لمعالجة قريبة من لب البئر.

من جهة أخرى نحن نرى أن تقنية المعالجة بمحورات النفاذية النسبية تمثل أحد الخيارات في مجال إدارة المياه وليست عامة التطبيق في جميع الحالات فيما يخص السيطرة على المياه.

Abstract: *With oilfields around the world becoming older and more mature, there is an increasing focus on the large quantities of water that are being produced and how these should be managed; both from an economic and environmental perspective. Relative Permeability Modifiers (RPMs) may be a simple and effective method of controlling water production without risking damage to any oil-producing zone. This is of particular interest for marginal wells where the operator cannot justify spending a significant budget allocation on fully diagnosing the nature of the problem for a blocking treatment or zonal isolation is not possible.*

The selective nature of RPM type treatments allows for a minimal amount of diagnosis to be used, however the degree to which water production is reduced will not be as significant as that for a blocking treatment. Modelling studies have shown however that, under certain circumstances, Bullhead Application of RPM Treatments in the Near Wellbore region (5-10 ft)

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can lead, not only to a reduction in the volume of water produced but also an increase in oil production.

This paper describes the area of Relative Permeability Modifier treatments and the approach that Baker Petrolite takes in the selection, design and evaluation of potential field applications. This includes the laboratory evaluation of the impact of the RPM treatment on a typical piece of reservoir core and the assessment of this laboratory response on the well in question, using a near wellbore treatment design model.

We stress, however, that we view RPM technology as simply one option in the area of water management and is not universally in all cases for water control.

INTRODUCTION

Water Management Costs and Activities

Water management is becoming an increasingly important cost issue as oilfields around the world mature and produce increasing quantities of water. Many major oil companies are now producing 50% (or greater) water in their produced fluids world-wide. The financial impact on handling such large volumes of water is extremely high, with recent estimates on the cost of handling produced water ranging from $0.20 to $4.00 per barrel of oil produced depending on the nature of the reservoir, the production environment etc. (Bailey[1]).

The costs discussed above account for the majority of the 'Water Management' activities listed below:

(i) The treatment and disposal of produced water.

(ii) The mitigation of the problems associated with produced water, i.e. mineral scale deposition, corrosion, demulsification, hydrates, *etc*.

(iii) The reduction in water production through the application of chemical or mechanical water shut-off techniques, including downhole separation.

(iv) The prediction of oil and water displacement and production, through simulation and modelling.

(v) The handling and treating of produced water specifically for re-injection (PWRI = Produced Water Re-Injection).

(vi) Intervention to reduce produced water by global field changes to well injection/production strategies. This is more of a reservoir management approach.

(vii) Installation of "intelligent" wells, which will respond to their environment using various sensors and will adapt by shutting off water-producing completions. These systems are likely to be introduced some time in the future.

(viii) The treatment of water for secondary recovery (water flooding). Though not strictly a produced water handling cost, it is still a Water Management activity that requires resources.

Baker Petrolite is particularly active in mitigating the problems associated with produced water (scale, corrosion, demulsification, *etc.*) and has interests in treatment of water for injection during secondary recovery (including Produced Water Re-Injection) and disposal (items i – iii and vi). There are, however, areas where the industry perceives that improvements in current technology are required and one of these is Chemical Water Control, in particular the application of Relative Permeability Modifiers.

Chemical Water Control Treatments

The origins of water production problems in reservoirs may be generally classified as due to matrix production (arising from the heterogeneity of the formation) or due to fractures (this can include cracks in production casing or the failed cement jobs) (Elphick[2]). The water source may be injected or may be due to an active aquifer. For the purpose of this paper only water production from matrix systems will be discussed.

The problem of a single reservoir zone producing 100% water with all other, non-communicating zones producing oil, has been identified by a number of engineers in the industry as being essentially solved (~80% success rate). The water producing zone can be mechanically isolated and the relevant gel treatment injected to completely block off the zone (Sydansk[3] and Seright[4]). Although this is a relatively simple case, it still requires extremely good diagnosis of the position of the water zone and a considerable amount of mechanical intervention to isolate it. Failure to achieve either of these design tasks can lead to gel misplacement and damage to the surrounding oil producing zones.

Although the problem and treatment described above is relatively simple, the application of such technology can be cost-prohibitive. The large amount of diagnosis required in identifying the water producing zone (production logging tools *etc.*) and the engineering needed to isolate it (packers/coiled tubing *etc*), which greatly increase the chances of success, can be expensive. Since most wells that require such a treatment are in their later life, the budget allocation that they have for remedial treatments may not be sufficient to cover these costs. In addition to the cost implications there are also well configurations where complete isolation of the water production zone is not possible (*e.g.* where gravel packs or sand screens have been used to minimise sand production).

A preferable option to minimise these complications, is to use a chemical treatment, known as a Relative Permeability Modifier (RPM) that can be bullheaded into the near well formation (Nieves[5], Faber[6], Zaitoun[7] and Zaitoun [8]). These chemical treatments are currently available and are known to restrict the flow of water more significantly than oil. However, they have also been found to have had sporadic success when applied in the field (approximately 40 - 50% success rate for the simple case discussed above). It is generally acknowledged that most matrix water production problems are more complicated than that discussed above and can contain simultaneously, 100% oil producing zones, two-phase (oil/water) production zones, layers of 100% water production, cross flow between different geological strata and possibly production of bottom water (aquifer).

Several studies have been performed to try and understand the mechanisms by which these materials work (Liang[9] [10], Mennella [11] and Singleton[12]. Improving the probability of success of these RPM treatments is one of the major challenges of chemical water control. The objective of this paper is to discuss the strategy that has been developed by Baker Petrolite in the evaluation and design of such RPM treatments for field application.

WATER CONTROL TREATMENT DESIGN STRATEGY

In order to correctly design and apply a successful Water Control Treatment several areas have to be addressed. These include defining the treatment philosophy and criteria for success, having a full understanding of how the chemical treatment interacts with the reservoir core and fluids (including permeability reductions to oil and water) and how these permeability reductions influence oil and water flows in a field production environment. This latter aspect is addressed by the use of a near wellbore treatment design model, where in addition to evaluating the impact of the permeability reductions, the treatment volumes and placement parameters can be optimised. These steps are now discussed in turn with a field example to illustrate the process.

Treatment Philosophy

From the previous discussion, comparing blocking treatments with those using Relative Permeability Modifiers, it is apparent that complete shut-off of the water production is an extremely difficult and risky task in terms of the potential loss of oil production. The treatment design philosophy that has been developed is to consider RPM/Water Control Treatments in a similar manner to Scale Inhibitor Squeeze treatments that are routinely performed in the field. Instead of aiming to completely shut-off water production, the RPM treatment is designed to a lower risk option that will yield "modest" reductions in water production with a subsequent increase in daily oil production over a period of ~200 days (around 6 months). Simulation studies have indicated that, under certain circumstances a reduction in the volume of water produced from the well will automatically yield an increase in oil production by advancing already available oil and adding incremental oil through improved sweep efficiency. An example of the predicted response of a production well to a Water Control Treatment is shown in the plot below (Fig. 1).

RPM CHEMISTRY

The Relative Permeability Modifier chemistry is a two-component system, which will enter the near wellbore formation in its un-reacted liquid state. Over the shut-in period (nominally 16hrs), this gelant solution is converted into a weak gel, which will "lip" out of the bottle holding it. This is in contrast with

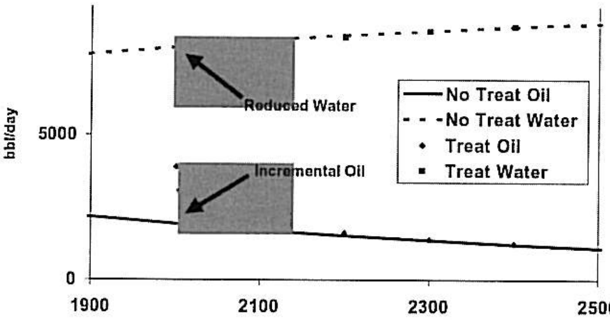

Fig. 1. Predicted treatment response for a production well.

the physical state of a blocking gel, which once gelled, will not flow from the bottle containing it. Examples of these two contrasting gel states are provided in the photographs below (Fig. 2).

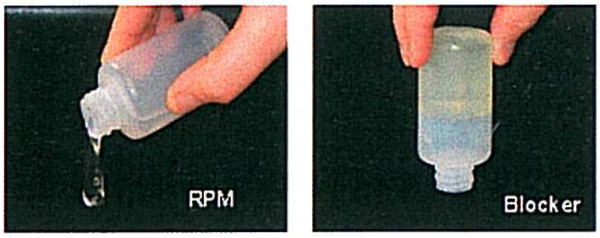

Fig. 2. Physical comparison of RPM Gel vs. a blocking gel.

Laboratory Evaluation

The main method of evaluating the impact of a Water Control Treatment in the laboratory is the use of coreflood experiments using oven housed coreflood rigs, shown schematically in Figure 3.

The experiments are performed under reservoir conditions, ideally using reservoir core and fluids, however when these are not available Clashach sandstone, iso-alkane oil and synthetic brines are used. The differential pressure across the core is recorded on the computer via the differential pressure transducer as Oil, Water and Treatment are pumped through it core during the various stages of the experiment:

(i) Water flow at 100% Water Saturation.
(ii) Pre-Treatment Oil Flow at Residual Water Saturation (S_{wi}).
(iii) Pre-Treatment Water Flow at Residual Oil Saturation (S_{or}).
(iv) Treatment Injection.
(v) Post Treatment Water Flow at Residual Oil Saturation (S_{or}).
(vi) Post Treatment Oil Flow at Residual Water Saturation (S_{wi}).

Measurement of the differential pressure across the core during steady state oil and water flow allows the permeabilities of both oil and water to be calculated for the various stages of the experiment, using Darcy's Law. The effectiveness of the treatment on modifying the relative permeabilities to oil and water are then quantified in terms of a Resistance Factor to oil or water flow (RF_w and RF_o respectively). These are defined as the ratio of the water (oil) permeabilities, k_w (k_o), before the polymer treatment to that following it.

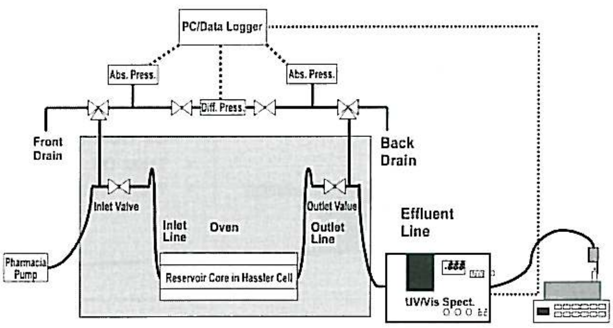

Fig. 3. Schematic of coreflood apparatus used to evaluate treatment performance.

i.e.

$$RF_w = \frac{k_w(at\ S_{or};\ pre-treatment)}{k_w(at\ S_{or};\ post-treatment)} \quad (1)$$

and

$$RF_o = \frac{k_o(at\ S_{wi};\ pre-treatment)}{k_o(at\ S_{wi};\ post-treatment)} \quad (2)$$

RPM Treatment Performance

During the development of the RPM treatment a series of coreflood experiments were performed to assess the effectiveness of the treatment in terms of Resistance Factors to Water and Oil on Clashach sandstone of various permeabilities. The Resistance Factors that were recorded for this series of experiments are summarised in the plots below (Figs. 4 and 5).

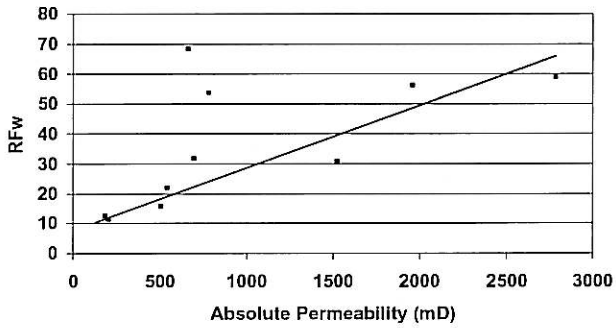

Fig. 4. Relationship between resistance factor to water and core absolute permeability.

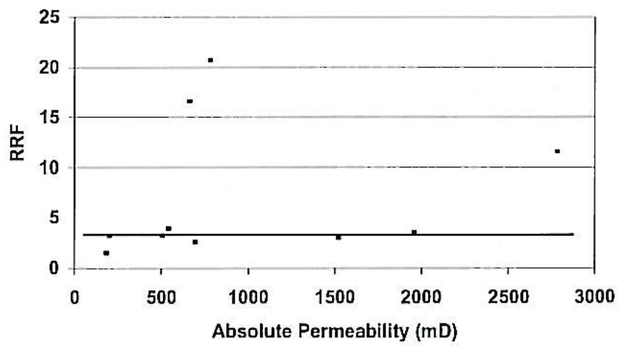

Fig. 5. Relationship between relative resistance factor and absolute permeability.

The Resistance Factor to water was found to increase as the absolute permeability of the core increased (Fig. 4). This was a surprising result and was in contrast to the results/trend that are quoted for a polymer only treatment. For polymer treatments, where a polymer layer thickness restricts water flow, its impact is diminished as the pore size (and permeability) increases. For gel treatments, a similar post treatment permeability was achieved for all cases and as a result the resistance factor that was achieved was greater for the cores with a larger initial permeability than those for a lower permeability.

Figure 5 summarises the impact of the treatment on oil permeability relative to the absolute permeability of the core. This is achieved by plotting the Relative Resistance Factor - RRF (defined as the ratio of RF_w/ RF_o) against Absolute Permeability. The general trend that was observed from these results was that the oil permeability reduction achieved was a factor of three lower than that achieved for water. There were a few outliers to this trend, however these were loaded in favour of RF_w.

Laboratory Evaluation of a Field Case

In order to design a field application of the RPM treatment it is necessary to assess the impact of the treatment under field conditions (Temperature, Permeability, Fluids *etc.*). For the field case that is to be discussed in this paper, no reservoir core or oil was available to perform the experiment. It was therefore necessary to use Clashach sandstone core (150mD) and synthetic oil (0.8cP) that matched that present in the field. The experimental method and apparatus used was that discussed above.

The resistance factors that were achieved for this application were found to be 13 for water (RF_w = 13) and 3 for oil (RF_o = 3). These reductions were then mathematically applied to the relative permeability curves that were supplied by the operator. The pre and post treatment permeability curves are plotted in Figure 6.

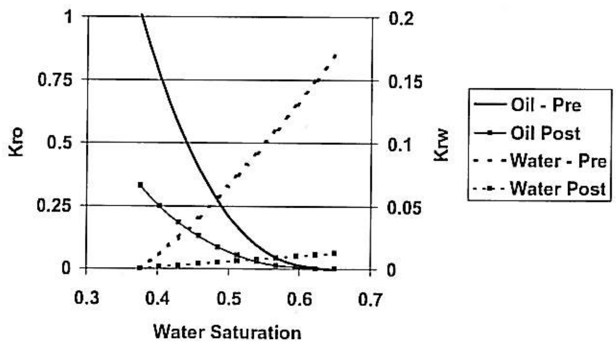

Fig. 6. Field case relative permeabilities: pre and post treatment (RF_w = 13 and RF_o = 3).

TREATMENT DESIGN – NEAR WELBORE MODELLING

Candidate well selection is a critical part of the Water Control Treatment process. Failure to identify the correct candidate well can lead to treatment failure and in certain circumstances a substantial loss of oil production. As a result of this, each potential treatment is evaluated prior to application.

This evaluation and the optimization of the treatment to be applied, is performed by a PC based Near Wellbore Model, similar to the SQUEEZE V design model that was developed by Heriot-Watt University for scale inhibitor squeeze treatments. The model has the ability to simulate the following phenomena:

(i) Oil and Water flow through the near wellbore formation.
(ii) Chemical injection and placement. Both of these are dependent on the properties of the chemical package and the formation rock, and also the treatment design (i.e. pre and post-flush size, pump rate etc).
(iii) The mechanisms by which the chemical is retained and how the chemical returns (adsorption/retention).
(iv) The effect of the retained chemical on the permeability of the formation rock to oil and water and how these changes affect the overall production rate.

This process enables the well technologist or production chemist to maximise the treatment's potential for success and establish its economic viability over a lifetime of 6 months.

Methodology

The methodology by which the evaluation and optimization takes place is as follows: The well details, including completion details, production rates, fluid properties, layer permeabilities and water saturation profile in the near wellbore region (estimated or from a reservoir model) are input into the data set. The producing well is then put onto production at the current production rate until the pre-treatment water cut has been established. At this point the treatment is injected into the near wellbore formation, where it penetrates the various producing layers based upon their permeabilities. In general, the treatment volume that is injected has been designed to ensure that the first five feet of the near well formation are penetrated, however this can be reduced depending on the response of the well. The oil and water relative permeability curves are then reduced by the pre-defined Resistance Factor (RF_o and RF_w respectively) based upon where the treatment has invaded the formation. The well is then returned to production and the resulting production profile is compared to what would have taken place if no action (treatment) had been taken.

The effectiveness of each well treatment is assessed by comparing oil and water production, over a period of 200 days following the treatment, to what would be achieved if no treatment were applied. The economic value of the treatment in terms of increased oil and reduced water production is then calculated based on the assumptions of the value of a barrel of oil ($20 per barrel) and the cost of handling a barrel of water ($0.25 per barrel). These values may vary depending on the current financial and operating conditions, however it is felt that the above values are suitable assumptions for this purpose.

N.B. It must be noted that no costing assumptions have been made in this assessment.

For example, if a well has an increased oil production of 1000 bbls, with water production reducing by the same amount the value of the well will be increased as below.

1000 barrels additional oil		
@ $20 per bbl	=	$20000
1000 barrels less water		
@ $0.25 per bbl	=	$2500
Well Value added over 200 days	=	$22500

Field Case Evaluation – Well "A"

The well to be discussed below is a candidate well, which is to be treated with the RPM treatment. It has three producing intervals with layer heights and permeabilities of 3ft, 14ft, 37ft and 20mD, 40mD and 80mD respectively. It has a daily production rate of 142bbl/day at a water cut of 84%. Figure 7 summarises its layer geometry.

A 60 bbl treatment volume is injected into the near wellbore region. This volume was initially calculated to achieve a uniform penetration of 5ft into all three layers. As can be seen in the Resistance Factor distribution plot below (Fig. 8), the heterogeneity of

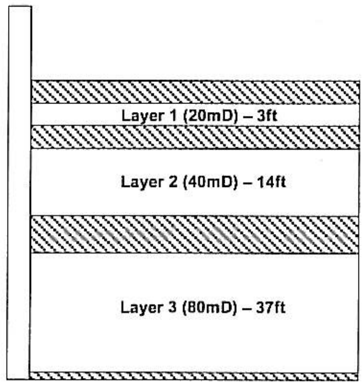

Fig. 7. Layer geometry of field case well "A".

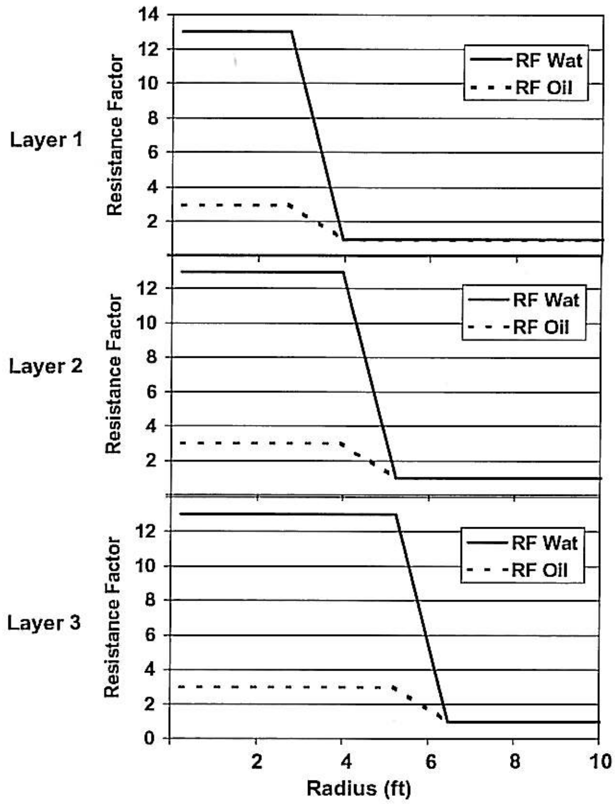

Fig. 8. Distribution of resistance factors from near wellbore model.

the near wellbore formation causes a variation of the treatment penetration based upon their respective permeabilities and layer heights (3ft, 4ft and ~5.5ft respectively). From the laboratory evaluation discussed previously resistance factors of 13 and 3 for oil and water respectively are applied to the formation, which has been exposed to the treatment based upon the treatment penetration discussed below. In addition to the distribution of resistance factors, the model is capable of monitoring the distribution of water saturations, chemicals (scale inhibitors or tracers) and treatment in the near wellbore, however due to limited space it has not been possible to present these here.

The evaluation of the well's response to this treatment is plotted in Figure 9 below. By comparing the treated and non-treated production volumes for oil and water, water production is seen to be reduced by ~900bbl with a corresponding increase in oil production of ~900bbl, over the 200 day lifetime of the treatment. This predicted outcome would yield a value of ~$20,000 based upon the assumptions made upon the value of oil and the cost of handling the produced water. This predicted outcome is only possible if the pre-treatment production rate is maintained following the treatment. Application of a Water Control Treatment by definition will restrict the ability of fluid to flow from the formation. In order to maintain the pre-treatment production rate it is therefore necessary to increase the differential pressure across the formation – i.e. increase the well's drawdown. In the case of Well "A" this equates to an increase of ~1000psi (69 bar).

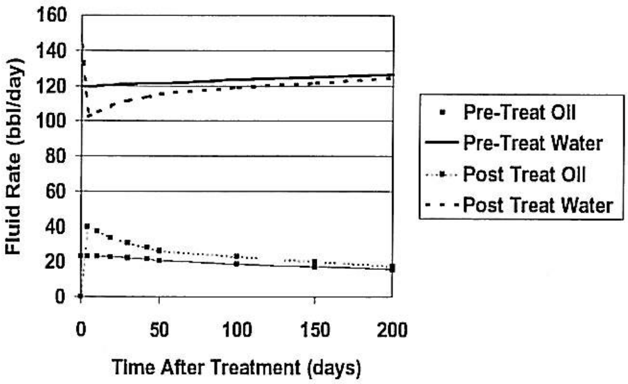

Fig. 9. Post treatment production response for well "A".

Field Case Evaluation – Well "B"

Well "B" is an illustration of the response of a poor candidate well. This well is a duplicate of that discussed above (Well "A"), however the heterogeneity observed there is not seen in this case with all three layers possessing the same permeability of 60mD.

The response of Well "B" is plotted in Figure 10. In contrast to the heterogeneous formation, Well "B" responds poorly. The treatment does reduce water production by ~110bbl however, to achieve this oil production also reduced by 163bbl. This is due to the inability of the well to maintain its pre-treatment production rate. The maximum draw down is applied to the well, however this is still not sufficient to maintain production.

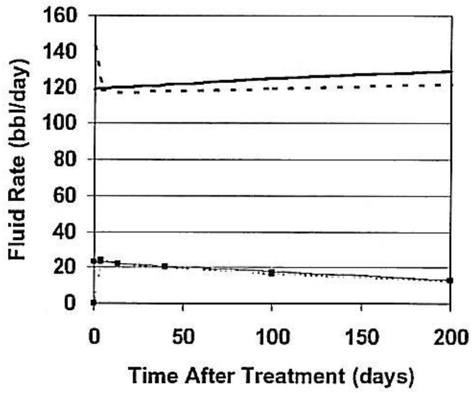

Fig. 10. Post treatment production response for well "B".

Theoretical High Volume Production Case Evaluation – Well "C"

This case was evaluated to illustrate the potential of applying RPM treatments to high volume production wells. The formation in question is a 3-layer system with each layer being 50ft deep. The top and bottom layers have a permeability of 200mD with the middle layer possessing a permeability of 1000mD. The production rate of the well is 10,000bbl of fluid per day with a water cut of 80%.

The same treatment as that discussed above was applied to this well to achieve a penetration depth of 5ft (500bbl). The resistance factors that were set up on gelation were also the same as those used for Wells "A" and "B" – $RF_w = 13$ and $RF_o = 3$. By maintaining the production rate at 10,000bbl of fluid per day the treatment is predicted to result in 58,000bbl less water and an additional 58,000bbl of

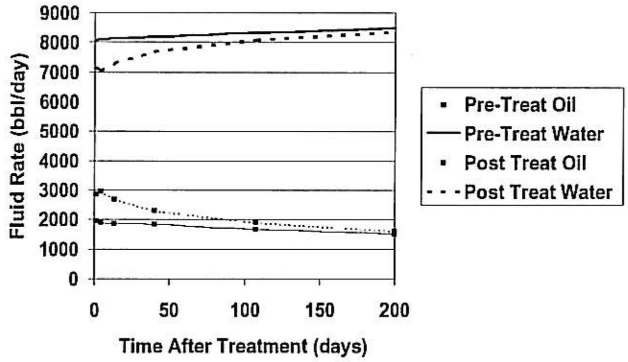

Fig. 11. Post treatment production response for well "C".

oil, which corresponds to $1.2 million of added value to the well. The response is summarised in Figure 11.

SUMMARY

Baker Petrolite, working closely with Heriot-Watt

University, has developed an approach for the design and evaluation of a RPM treatment package that is a combination of experimental core flooding tests, near well modelling and chemistry. The combined understanding of how reservoir and chemical properties influence the success or failure of a treatment and the ability to model several treatment scenarios provides a novel approach which will help to improve the success rate of RPM treatments and provide significant value to the customer.

This approach is currently in the field validation phase and Baker Petrolite are currently pursuing several field trial opportunities which will be reported on in due course.

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