Emulsion Problems in Producing Wells in a Xanthan Polymer Flood Project after Polymer Break-Through

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Abstract

A commercial scale polymer flood project has been performed in a part of a North German oil field. The polymer flood with xanthan was started in January 1990 after water flooding. The polymer concentration was 600 ppm and 58 000 kg of active xanthan were injected. In one well, which is the nearest to the injection well at a distance of 160 m, polymer break-through occurred in the middle of 1992. This well was used as an observation well in the project and was producing at a water cut of 100 % for a period of about 2 years.

Jointly with polymer breakthrough also additional oil was recovered. Oil cut was about 0.5 - 1% in the beginning and polymer concentration was 20 - 50 ppm. In the beginning of 1993 polymer concentration increased and was about 200 - 300 ppm at the end of 1993. In the same time the oil cut rose to 2 - 3 % and is still increasing.

The oil was produced in an emulsion with the polymer solution, that could not easily be separated. This caused at first problems in the determination of oil cut. Laboratory investigations were performed to analyse the coalescing behaviour of the oil droplets in the polymer containing water phase. The produced polymer was examined with respect to viscosity yield and surface activity. The viscosity yield was the same as of the injected solution. A reduction of interfacial tension between xanthan solutions and the oil was found.

A method to separate oil and water was developed to be applied in the surface facilities in the oil field. This is important for the future production from the field, when polymer break-through and the oil bank will occur in the 2 main producers in the future.

1 Introduction

In December 1989 a polymer pilot project was started in the Vorhop-Knesebeck oil field. The polymer used was a xanthan in the form of broth, which had a concentration of about 3.5 % of active polymer.

The project was performed in the upper layer of the Dogger-ß sandstone of the block "H3a" of the Vorhop-Knesebeck oil field. This part of the reservoir is separated from all the other parts of the oil field by faults and comprises 4 wells. The total pore volume is approximately 430 000 m^3. It was intended to flood a slug of polymer of approximately 40 % of the pore volume with xanthan at a concentration of 500 - 600 ppm, which gives a viscosity of the polymer solution of 4 mPas under reservoir conditions, which is the same as the oil viscosity.

The polymer solution was injected into one well, which was used before for water injection, at a rate of 136 m^3/d. The injection time was 36 months. The amount of polymer was 58 000 kg of active material.

The performance of the project was modelled by numerical reservoir simulation. A response to polymer flooding was observed in all wells. The one well, which is located the nearest to the injection well, was producing at a 100 % water cut for a period of about 1 year. Simultaneously with the increase in oil cut from zero to about 3 % polymer break-through occurred. The wet oil, that was produced, was strongly emulsified. The emulsions were very stable and could not easily be broken by use of regular oil field demulsifiers.

Therefore it is essential for the further production from the polymer project to find out the mechanisms how these stable emulsions are formed and how they are stabilised. Before this is discussed in the following a short description of the project is given.

2 Reservoir description

The polymer project was performed in block "H3a upper layer" , which comprises the wells VK8, VK45, VK48, and VKH3a. It was developed in 1959 with well VK8. This well produced until 1986 about 67 000 m^3 stock tank oil. Since the 8th of May 1982 well VK45 is producing from this unit and since 22nd of December 1982 well VK48. The structure map of the pilot area is shown Fig. 1.

Due to production in well VK8 the pressure decreased in this unit within 4 years from 13 MPa to the bubble point pressure of 1.5 MPa after a production of 14 000 m^3. After that the production mechanism was solution gas drive and the reservoir pressure stayed constant at the bubble point. This proves, that the unit is an under saturated, confined reservoir.

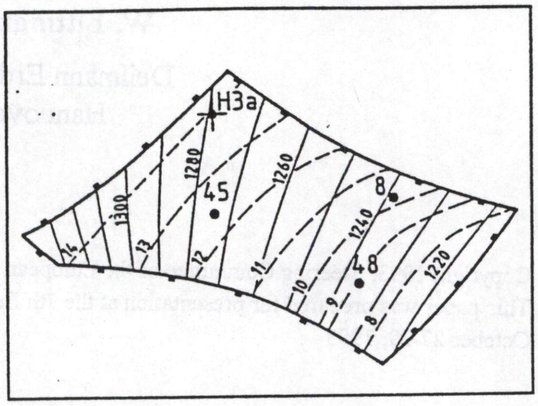

Fig. 1: Structure map of block "H3a" (polymer project area)

Since April 1984 the most up dip well VK48 was produced with a steadily decreasing production rate and since August 1984 GOR was increasing.

From October 1984 until March 1985 production was maintained by pressure relief in the casing. After this had been stopped, casing pressure was increasing and the fluid level was decreasing, so that production was no longer possible since March 1985.

To restart production well H3 was drilled in October 1986 for water injection. This well did not reach the structure at the desired position, but was landing on the other side of a fault in the neighbour block. So this well was deviated to well H3a which met the reservoir at the location as shown in Fig. 1.

Water injection into well VKH3a was started in February 1987. The reservoir pressure increased very quickly, so that production could be started in July 1987 from well VK48 and VK45 again and production from well VK8 could be increased.

The reservoir parameters relevant for the polymer flood project are summarised in Table 1.

Table 1: Reservoir parameters polymer project Vorhop Knesebeck

Depth	1250	m
Area	145 000	m^2
Thickness	8 - 14	m
Porosity	27	%
Pore volume	430 000	m^3
init. water sat.	14	%
OOIP	370 000	Res. m^3
Form. vol. fact.	1.04	
Form. temp.	56	°C
Oil viscosity	3.5	mPa s
Oil density	860	kg/m^3
Salinity	210	kg/m^3
Permeability	1000	mD

In Fig. 2 the log sequence of the upper layer in well VK48 is given together with the results of the core analysis. This figure shows that the upper layer may be subdevided into two layers. Permeability varies from about 1000 - 5000 mD in the upper part to about 500 mD in the lower part.

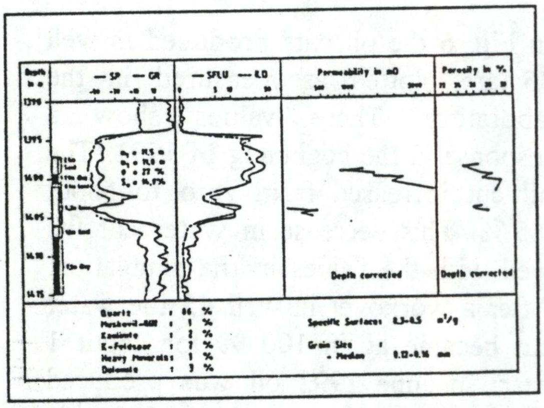

Fig. 2: Log and core data from well VK48

The assumption, that the upper layer of the reservoir may be divided into 2 layers, which are separated by a sealing shale layer, could be proven by permeability measurements using a mini-permeameter.

3 Project performance

3.1 Injection performance

The injection performance can be seen in Fig. 3 and 4. Fig. 3 shows the increase in well head pressure of the injection well H3a during the first days after start of injection. The pressure of 20 bars during water injection was taken as zero, so that this figure only shows the pressure increase due to the higher viscosity. The figure shows measured and calculated values.

It can be seen that the pressure increased very quickly within 35 hours by about 40 bars and reached a stable value after about three days.

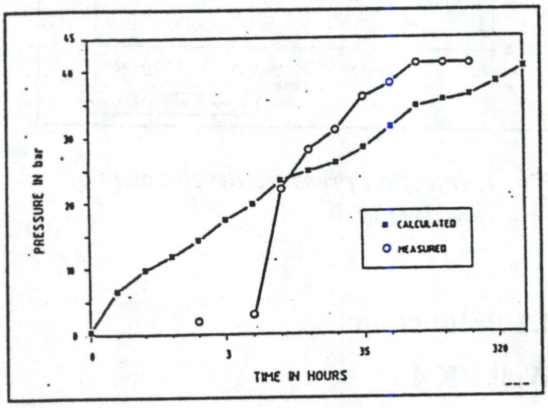

Fig. 3: Calculated and measured increase in well head injection pressure

This pressure increase was calculated by assuming a water permeability of 180 mD and a viscosity of 10 mPas. The permeability corresponds to the permeability to water at residual oil saturation, the viscosity to a temperature of about 20 °C. The temperature around the injection well was cooled down by the injection water, which had a surface temperature of about 15 °C. Fig. 3 shows that the calculated values fit rather good with the measured data.

The long term development of the injection pressure is shown in Fig. 4. Together with the well head pressure the reservoir pressure is shown as measured in well VK 45. From this plot it can easily be seen, that after the injection pressure had reached the stable value as described before no further increase occurred. Variations in injection pressure follow variations in reservoir pressure (represented by the flowing pressure of well VK45). During the whole project period the injection pressure remained nearly constant at around 70 bar (7 MPa).

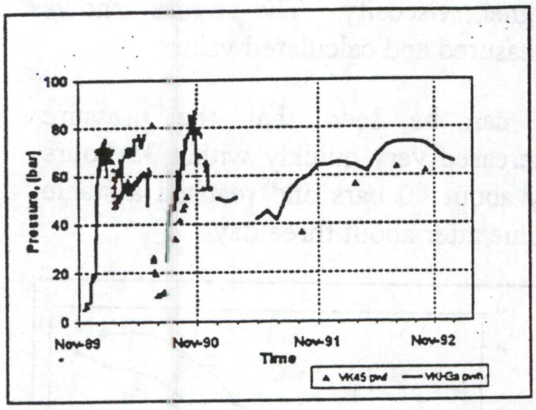

Fig. 4: Injection pressure development of well H3a.

3.2 Production

Well VK 45

In Fig. 5 the simulated water cut and the values from the field are plotted. The field values are monthly averages. Well 45 was producing at a 100 % water cut since the beginning of 1990. This behaviour could not be matched by the simulation. The highest water cut in the simulation was about 98 %. A response to polymer flooding in the simulation may be observed in the middle of 1991 with a reduction in water cut as compared to the pure water flood case of about 1.5 %.

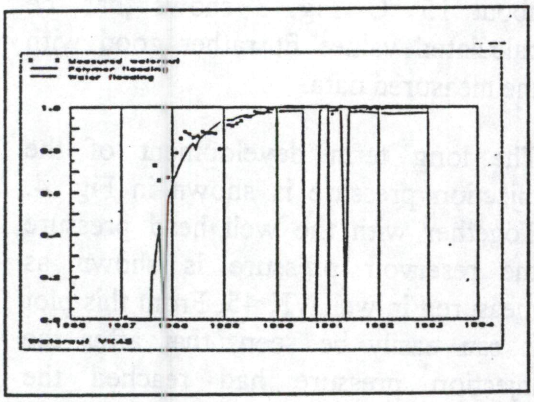

Fig. 5: Water cut of well 45. Simulation and measured field data.

In the data measured in the field (Fig. 5) no significant response may be seen. The accuracy of these data is not very high, as the water cut is measured by a very simple volumetric method in a field lab and further these data are averaged by a statistical computer program, so that there are almost only values of 100 %.

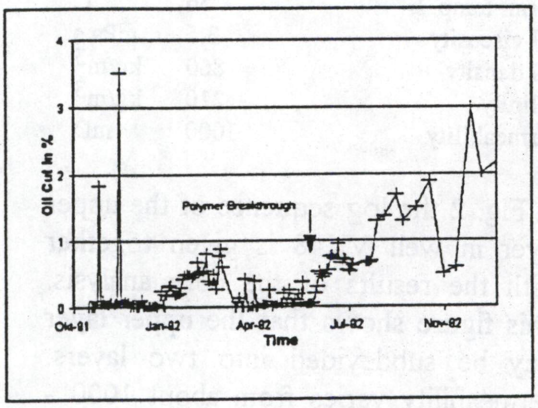

Fig. 6: Oil cut in well 45 as measured in the laboratory.

In Fig. 6 the oil cuts produced in well 45 are plotted as measured in the laboratory. These values show a response in the beginning of 1991. The oil cut increased from zero to about 0.5 %. This decrease in water cut fits well with the values in the simulation. After a workover in well 45 the water cut became again 100 % for about 1 year. In June 1992 oil was produced again. This oil was produced in stable emulsions, which could not be separated easily. This is also the reason why nearly 100 % water cut was found in the field lab.

Until the end of 1992 the oil cut increased to about 2.5 % and is still increasing.

Polymer breakthrough was in the beginning of 1991 and stayed at a level of about 20 ppm for about one and a half year. At the same time, when oil cut increased the polymer concentration in well 45 also increased. In July 1992 values of about 150 ppm were measured. From viscosity measurement a value of about 200 ppm was determined in December 1992. The simulation was performed with an adsorption of 5, 10 and 20 µg/g (Fig. 7). The best fit is obtained with an adsorption of 20 µg/g, what is relatively small as compared to laboratory data from literature.

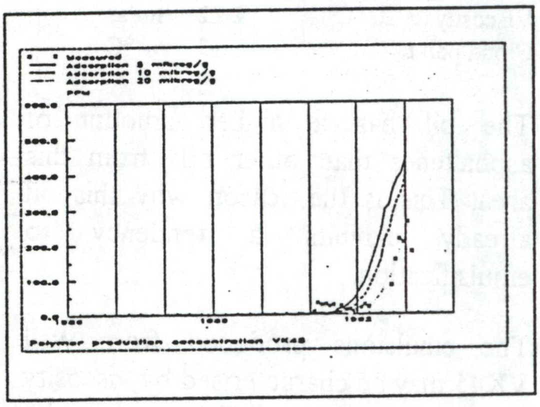

Fig. 7: Polymer concentration in production well 45, measured and simulated

Well VK 8

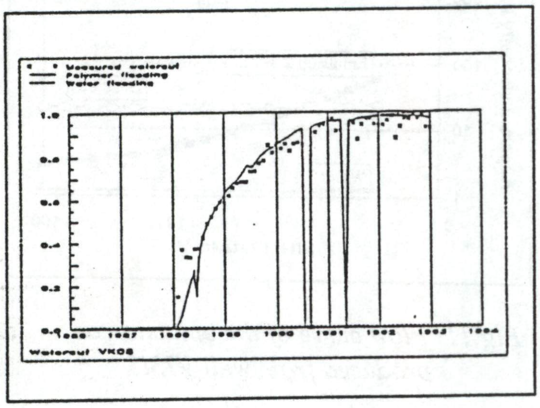

Fig. 8: Water cut of well 8. Simulation and measured field data.

In well 8 the measured and simulated data for water cut still match very well. A response to polymer flooding should occur at the end of 1992 according to the simulation. In fact a decrease in water cut was observed. Some samples from this well even had water cuts of about 85 %. But it is still too early to verify this trend.

Polymer breakthrough in well 8 should, according to the simulation, occur in the beginning of 1993. Samples from this well, taken in 1992, had only traces of xanthan and formaldehyde.

Well VK 48

According to the simulation the water cut in well 48 should be 60 %, whereas 63 % were measured in the field. The field data still fit the water flood case and not the polymer case (Fig. 9). But here also it is still too early to judge on the performance of the project.

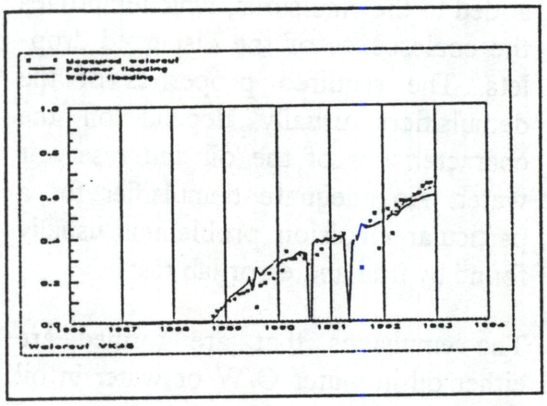

Fig. 9: Water cut of well 48. Simulation and measured field data.

4 Emulsion problems

Problems during oil production from the polymer pilot area were first identified by an increase of the salt content in the oil from the whole field. It was found that the problem was caused by well VK8, which produced from the polymer pilot area. Samples taken from this well and well VK45 showed, that the emulsions produced could not be separated as easily as those from all the other wells. This also caused problems in the determination of water cut by well checker measurements. As the emulsions did not separate quick enough the oil cuts measured in the field were always lower than those measured in the laboratory.

There was nothing found in the literature, neither in field reports nor in laboratory flood experiments, that such stable emulsions may occur during production from a polymer flood.

The prerequisites that emulsions may be formed during production of crude oil are that oil and water are produced simultaneously, that there is enough energy input during the flow in order to mix the 2 phases and that the interfacial tension between the 2 phases is low enough.

For demulsification purposes in the oil field usually a surface active agent is added to the emulsions, which improves the coalescence of the dispersed droplets. The required properties of the demulsifiers usually depend on the characteristics of the oil and reservoir water. An adequate demulsifier for a particular emulsion problem is usually found by trial and error lab tests.

The emulsions that are formed are either oil in water O/W or water in oil W/O emulsions.

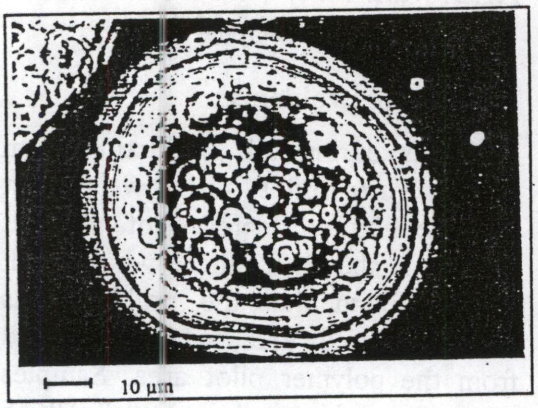

Fig. 10: Micrograph of the emulsion

In the case of the emulsions from well VK45 it was found, that the emulsions are oil in water, but that in the oil droplets again water was present and that then again oil was emulsified in this water. This is shown in Fig. 10. The average oil in water droplet size is below 10 µm for about 80 % of the droplets.

4.1 Characterisation of the emulsions

The composition of the oil is given in Table 2.

Table 2: Composition of the Vorhop-Knesebeck dead crude oil

Dispersant	98.60	%
Raisins	0.19	%
Asphaltenes	1.21	%
Density @ 20 °C	0.865	g/L
Viscosity @ 20 °C	24.2	mPas
Cloud point	-3	°C

The oil has a higher amount of asphaltenes than other oils from this area. This is the reason why this oil already exhibits a tendency to emulsification.

The emulsions produced from well VK45 may be characterised by viscosity and the separation stability measured by electrical conductivity.

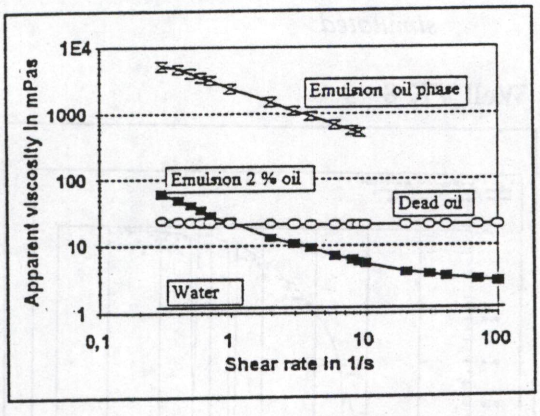

Fig 11: Flow curve of the emulsion as produced from well VK45

The flow curve of the emulsion exhibits a strong non-Newtonian behaviour and the viscosity is higher than the viscosity of the two single phases.

In Fig. 12 the separation behaviour of two different emulsions is shown. The separation rate was determined by measuring the electric conductivity at the bottom and at the top of the emulsions as described by SCHAMBIL.

The difference in conductivity is plotted versus time.

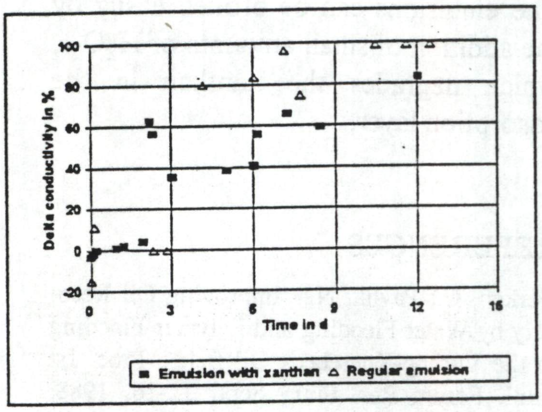

Fig 12: Conductivity of emulsions as a function of time

It is obvious that the emulsion containing xanthan is much more stable than an emulsion, which was produced from the same oil and water but without xanthan.

4.2 Surface tension

The very small droplets in the emulsion as shown in Fig. 11 and the stability of the emulsions indicate that interfacial tension may be an important factor to explain the observed behaviour.

Spreading pressure was measured as follows: a small droplet of the produced oil from different wells was added to synthetic injection brine. The spontaneous spreading or decrease in surface tension is shown in Fig. 13. The oil produced from well VK45 is much more active than the oil produced from a well before polymer breakthrough (VK8) and a well outside of the project area (VK51).

It is surprising that the relatively high surface tension of 35 mN/m, which was measured, already leads to the very stable emulsions. Such emulsions are usually obtained below values of 10 mN/m in laboratory experiments.

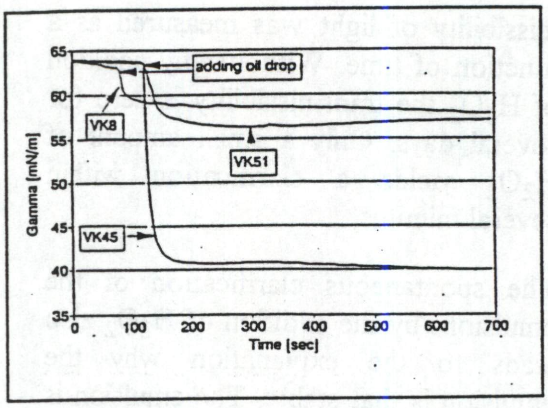

Fig. 13: Surface tension of different produced oils

4.3 Solution of the problem

To handle the problem of the stable emulsions produced from the polymer project different possible solutions were investigated.

Heating the emulsions would improve demulsification, but temperatures of about 60 °C would be necessary. Heating the total production from the pilot area would need significant additional investment and cost.

Some regular demulsifiers helped a little bit to increase the separation of oil, but the settling times needed were still too long.

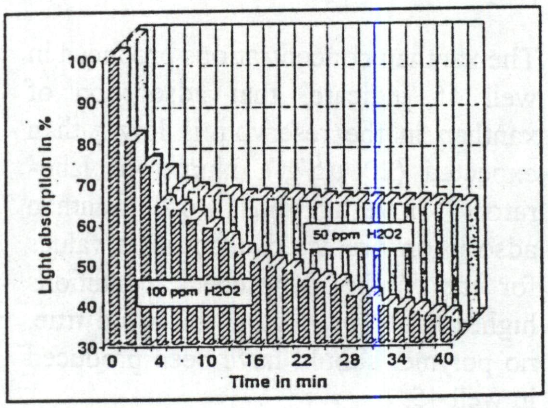

Fig 14.: Clarification of the emulsion by H_2O_2, shown by the transmissibility for light.

The problem could simply be solved by adding H_2O_2 to the emulsion as is shown in Fig. 14. Here the transmissibility of light was measured as a function of time. Without any addition of H_2O_2 the transmissibility is zero for several days. Only a small amount of H_2O_2 yields a clarification within several minutes.

The spontaneous clarification of the emulsions by the addition of H_2O_2 also leads to the explanation why the emulsion is that stable. The emulsion is stabilised by a layer of xanthan, which is adsorbed at the surface of the oil droplets. As soon as the xanthan is destroyed the emulsion problem disappears.

5 Conclusions

Xanthan injection was possible at the planned rates. No problems occurred. The pressure increase after start of the polymer project corresponded to the viscosity of the polymer solution in the reservoir.

In technical terms the project may be regarded as successful.

In well 45 water cut decreased from 100 % to about 97 % up to now and seems to be still decreasing. This is more, than the established theory about polymer flooding allows.

The xanthan concentrations produced in well 45 indicate, that adsorption of xanthan in the reservoir is lower than expected (20 µg/g.). Numerous laboratory investigations on xanthan adsorption predicted adsorption values for the Vorhop-Knesebeck conditions higher than 70 µg/g. If this were true, no polymer should have been produced in well 45.

Severe emulsion problems and foaming of the oil occurred during production

The emulsions were identified to be formed by a decrease in interfacial tension and stabilised by the adsorption of xanthan in the interface between water and oil.

The emulsions can be broken easily by the addition of small amounts of H_2O_2, which degrades the xanthan in the adsorption layer.

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