Polymer Flooding: Appraisal of Four Different Field Projects in Germany

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Abstract

Preussag accomplished four polymer flood projects during the last 10 years in their oil fields in Germany. In three projects (Eddesse-Nord, Vorhop-Knesebeck and Scheerhorn) xanthan broths were used from different producers. The project in the Adorf field was carried out with polyacrylamide.

The projects were performed under different reservoir conditions with respect to temperature (20 - 70 °C) salinity (20 -200 000 ppm) and oil viscosity (3.5 - 30 mPas).

The projects and their performance are described in detail, regarding the different reservoir conditions and the applied chemical systems. Results on polymer injectability from the field tests are given as well as on polymer stability and adsorption. These field results are compared with laboratory data from the screening and planning phases of the projects.

The incremental oil recovery observed is compared with results from numerical reservoir simulation. At least 2 projects can be regarded as technical successful in terms of incremental oil recovery. The reasons for the partial failure of the other two projects are discussed.

Zusammenfassung

Die Preussag Energie GmbH führte in den letzten 10 Jahren vier Polymerflutprojekte in ihren deutschen Ölfeldern durch. In drei Feldern (Eddesse-Nord, Vorhop-Knesebeck und Scheerhorn) wurden xanthan-haltige Lösungen als Flutungsmittel eingesetzt; im Projekt im Feld Adorf fand Polyacrylamid Anwendung.

Die Flutungsmaßnahmen wurden unter verschiedenen Lagerstättenbedingungen, insbesondere bei unterschiedlichen Temperaturen (20 – 70°C), Salinitäten (20 – 200.000 ppm) und Ölviskositäten (3,5 – 30 mPas) durchgeführt.

In diesem Beitrag wird im Detail auf die unterschiedlichen Reservoirbedingungen und die eingesetzten Chemikaliensysteme eingegangen.

Die Ergebnisse der Feldtests hinsichtlich der Injizierbarkeit, der Polymer-Stabilität und der Adsorption werden mit Labordaten und prognostizierten Daten der Projektplanungsphase verglichen.

Die zu beobachtende Zunahme des Entölungsgrades durch Polymerflutmaßnahmen wird mit den Ergebnissen der numerischen Lagerstättensimulation verglichen. Zwei der vier Projekte können als technisch erfolgreich im Sinne eines höheren Entölungsgrades gewertet werden, die Gründe für das partielle Mißlingen der beiden anderen Projekte werden diskutiert.

1. Introduction

The situation in the oil fields operated by Preussag was characterized by increasing water cuts, which had already reached an average value of about 80 % and in some cases up to 97 %, which is close to the economic limit. This is why Enhanced Oil Recovery is of major concern for these oil fields.

Besides steam flooding, which was applied in several fields with heavy oils, surfactant flooding and polymer flooding were expected to be the most suitable EOR methods for many of these oil fields. As polymer flooding was regarded as the only chemical method, that is technical and also economical feasible, a xanthan polymer pilot project was started in 1984 in the small oil field Eddesse-Nord.

This reservoir is shallow with depths between 150 to 350 m, which was favourable for drilling and workover, but a

constraint for injection pressure, especially during polymer injection. Also temperature is very low with 21 °C, which may lead to high adsorption of chemicals and high levels of bacterial activity. The relatively high clay content of about 10 % was also not very favourable.

At about the same time another polymer flood was started in the Adorf field using polyacrylamide. The reservoir is at a depth of 1 350 m, temperature is 68 °C. The initial salinity of the reservoir brine was 250 g/L. For this reason fresh water was injected as a pre-flush in order to bring down the salinity in the reservoir to a level, where polyacrylamide could be used.

Though the Adorf project was already a large-scale project, based on a proven technology, it was also meant as pilot for the rest of the field and the large oil field Scheerhorn.

In both pilot projects no problems occurred in the mixing and injection of the polymer solutions. The injectability of the polymers was monitored in the laboratory, where every batch that was used had to be approved. In these terms both projects could be regarded as technical successful, but it was found, that the use of polyacrylamide was not suitable under the conditions in the Adorf and Scheerhorn field. The main reason was not only, that the result of the Adorf project was rather disappointing in terms of incremental oil recovery, but more the problem to handle the large amount of fresh water necessary for flooding using PAA and to dispose the produced reservoir brine.

Therefore the other two projects were carried out using xanthan. The Scheerhorn field is about 1 000 m deep, the reservoir temperature is 49 °C and the salinity of the reservoir water is 77 g/l. The viscosity of the Scheerhorn oil under reservoir conditions was 30 mPas and the permeability of the sandstone about 2 000 mD.

The sandstone in the Vorhop-Knesebeck field is at a depth of 1 250 m, the salinity of the reservoir water is 210 g/L. The oil viscosity of 3.5 mPas is relatively low for a polymer flood. The main reason, why this field was chosen, was the sealed fault block and that the project should be a pilot for the North sea fields of Statoil, which was a partner in this project. A xanthan developed and produced by Statoil was used in this project.

2. Description of the reservoirs

In the following a short description of the reservoirs is given. A more detailed overview of the Eddesse-Nord and Vorhop-Knesebeck project can be found elsewhere [1,2,3].

2.1 Eddesse-Nord

The small block chosen for the pilot project is shown in Figure 1. This block is separated from the rest of the field by two sealing faults. Nine wells were drilled in this block in total, so that the structure was known quite well. Five of these nine wells were still open and could be used for the polymer project.

The reservoir is divided into several different layers from which layer M was chosen for the pilot project. The reservoir data are summarized in Table 4 together with those of the other projects at the end of the paper.
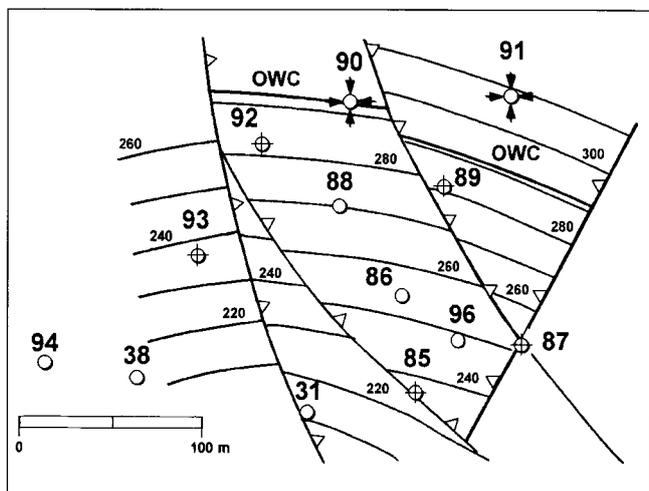
Fig. 1: Structural map of the Eddesse-Nord project area.

Abb. 1: Strukturkarte des Eddesse-Nord Feldes.

All the wells drilled originally in this block were producing from different layers. Therefore in primary and secondary operations oil was produced only from well 90, which was because of the down dip position of this well not the optimum. Only during a short period water was injected into well 91 to maintain the reservoir pressure. Due to the weak aquifer during primary production the pressure then fell below the bubble point and a secondary gas cap developed in the up dip part of the structure. Though well 90 is located near the oil water contact it could be produced at water cuts of 50 - 70 % at low rates for a long period. Cumulative production in 1984 was 7085 m³ tank oil or 35 % of the original oil in place.

Well 96 was drilled in the up dip part of the reservoir before the polymer flood was started. The well was entirely cored in the reservoir zones in order to get fresh and representative core material for laboratory investigations.

2.2 Adorf

The project was performed in a small longly stretched block, having an oil water contact. The block was totally separated from the rest of the field. Five wells were completed in the Bentheim Sandstone, three producers, one injector for polymer (10) and one back-pressure well (H2a) to prevent the flow of polymer into the aquifer. The reservoir depth is 1350 m, the temperature 68 °C. The original reservoir brine had a salinity of 250 g/L. A structure map of the pilot area is shown in Figure 2.
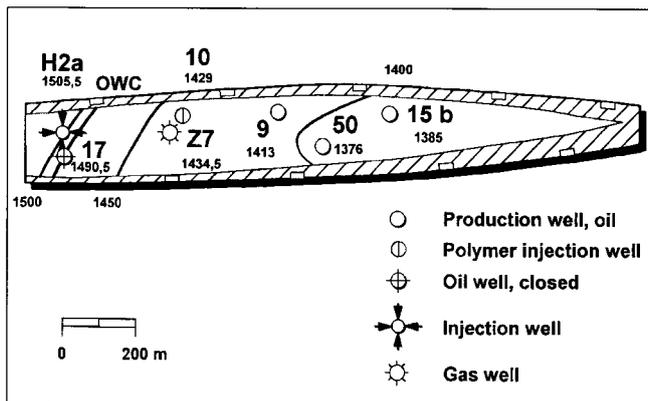
Fig. 2: Adorf pilot area.

Abb. 2: Projektgebiet Adorf.

2.3 Vorhop-Knesebeck

The project area in block „H3a upper layer" comprises the wells VK8, VK45, VK48, and VKH3a and was developed in 1959 with well VK8. Since the 8th of May 1982 well VK45 is producing from this unit and since 22nd of December 1982 well VK48.

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 that the production mechanism was solution gas drive and the reservoir pressure stayed constant at the bubble point. This shows that the unit is a confined reservoir with secondary gas cap.

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 with pressure relief in the casing. Production was no longer possible since March 1985 due to low flowing pressure.

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 found the reservoir at the location as shown in Figure 3.

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

Block „H3a upper layer" is confined by sealing faults, but there is a small communication with the lower layer of the block in the North and also, with the block in the East. As long as there is no big pressure difference between these blocks the fluid flow across the faults is supposed very small.

2.4 Scheerhorn

The oil field Scheerhorn is located in north-west Germany near the Dutch border. Oil is produced from four different zones, where the Bentheim-Sandstone (Valanginian) is the main producing layer. About 120 wells were drilled in the field. For a pilot project a small area in the north, near the transgression was chosen, having the advantage, that the thickness of the reservoir is small (5 m) as compared to the main area of the field (30 m). The pilot area is shown in Figure 4.
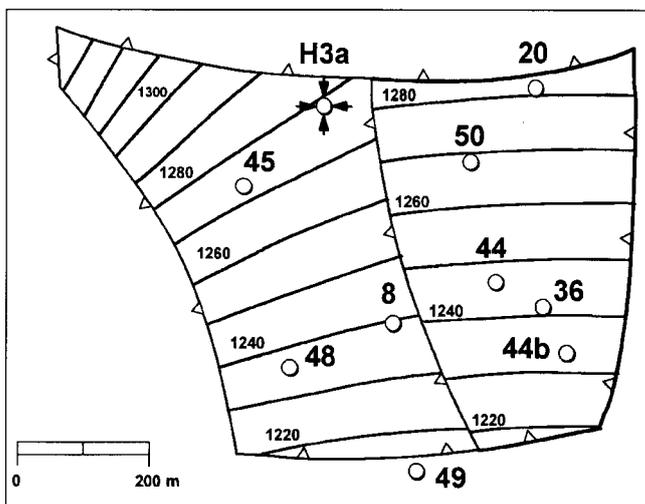
Fig. 3: Structure map of the block H3a Vorhop-Knesebeck polymer flood project.

Abb. 3: Strukturkarte des Blockes H3a Vorhop-Knesebeck.
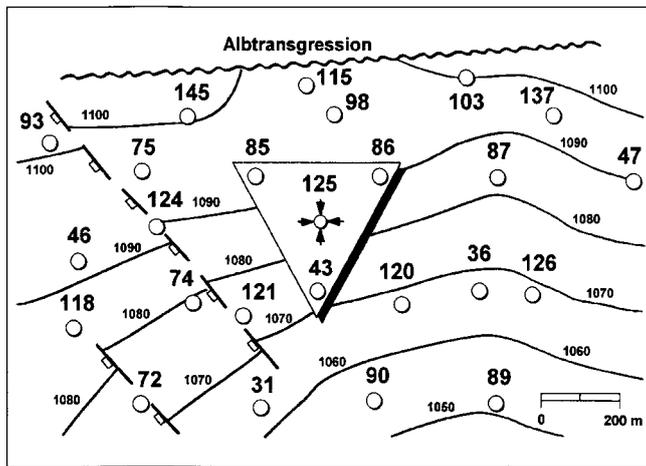
Fig. 4: Pilot area - Scheerhorn.

Abb. 4: Projektgebiet Scheerhorn.

The lower layer of the Bentheim-sandstone was chosen for the pilot. The reservoir depth is about 1080 m and the temperature 49 °C. The salinity in the different parts of the reservoir varies between 50 and 200 g/L, as different injection waters were used, from other oil fields as well as fresh water. The salinity development could be used like a tracer to monitor the communication between different wells.

The oil viscosity was 30 mPas under reservoir conditions, the permeability of the sandstone about 2 000 mD. Due to the high oil viscosity, the recovery of the oil field was only about 20 % of the OOIP at a water cut of 98 %. These are in principal favourable conditions for polymer flooding, as the oil saturation is still high and the mobility ratio may be improved significantly.

3. Polymer injection

Before the start of all the polymer projects a thorough screening was performed to find the most suitable polymer with respect to viscosity yield, injectability and cost. Another point was to ensure polymer stability in the reservoir and to minimise adsorption.

3.1 Eddesse-Nord

Before polymer injection was started a water preflush of 10 300 m³ was injected into well 91 in order to repressurize the reservoir and thus reduce the secondary gas cap and to gain more data by the water flood performance for the planning of the polymer flood. Formaldehyde was injected together with the water as a tracer and as a biocide for the following polymer slug.

A xanthan polymer solution containing 800 - 1000 ppm of active xanthan was injected into wells 90 and 91 at a rate of 10 - 12 m³/d in each well. Polymer injection started in November 1985 and ended in May 1988. The injection well head pressure was 1.5 - 2.0 MPa in well 90 and 1.0 MPa in well 91. No injectivity problems occurred. Details about polymer mixing, injection and quality control are described elsewhere [4,5,6].

The xanthan used for the project was produced in a 40 m³ fermentor on a pilot scale by BAYER. The 2 % broth from the fermentor was transported to the field and directly diluted in the injection water to the desired concentration.

The fermentation process for xanthan was improved in order to obtain a product for enhanced oil recovery. This led to a product with a lower viscosity yield as e.g. xanthans used in other applications but a much better injectability. This was

mainly due to the lower pyruvate content. The pyruvate group at the end of one side chain of the molecule is mainly, besides the acetate group, responsible for the anionic character of the makro-molecule.

3.2 Adorf

The polymer that was used was a partially hydrolysed polyacrylamide commercially produced and delivered as an emulsion. The active concentration of the emulsion was 33 %.

As for this project polyacrylamide was used, which is very salt sensitive [6], it was necessary to reduce the initial salinity. The reservoir therefore was flooded with fresh water. This water had a hardness corresponding to 16 mg CaO/L (16 °dH). In such a water a polymer solution with a concentration of 800 ppm (active) had a viscosity of 20 mPas at a shear rate of 7 s⁻¹.

3.3 Vorhop-Knesebeck

The polymer was produced at the Statoil Biocenter in Stavanger. The xanthan broth came from the fermentor at a concentration of about 3 % active material. As the investment for further concentration of the polymer broth is very high the polymer was shipped at this concentration to Germany.

The polymer was shipped in 23 m³ tank containers from Stavanger to Hamburg. These containers were then transported to the field, where the polymer was drawn directly from the containers and mixed with the injection water. The injection water was the separated water from the oil production. Before the water was mixed with polymer hydrochloric acid, formaldehyde and citric acid were added.

3.4 Scheerhorn

In this project a commercial high pyruvate xanthan was used. This and the higher concentration were the main differences to the xanthan used in the other two projects. Due to the higher pyruvic content, the polymer solutions had a higher viscosity yield. Our interpretation for the higher viscosity yield was not a higher molecular weight, but the formation of aggregates of the polymer chains because of the higher charges at the molecule according to the higher pyruvic content. This happened especially in the presence of 2-valent ions as Ca^{2+}. The aggregation of polymer molecules not only led to a higher viscosity yield, but also to a worse injectability, which was still tolerable, but for some batches caused problems.

The mixing and injection scheme was similar to that of the other xanthan projects.

4. Production performance

4.1 Eddesse-Nord

Production in well 96 was started in March 1985. After producing 1200 m³ (Vn) of gas the well could produce at a rate of 3 - 4 m³/d with little water. As this production rate was too low (only 25 % of the injection rate) and a further acceleration was not possible, well 88 was also put into production in May 1986 and well 86 in March 1987.

In Figure 5 the water cut developments of well 96 are shown together with the results of a numerical reservoir simulation.

The reservoir simulation was performed with a black oil simulator and for the polymer prediction a polymer option was used.

Though well 96 is the most distant from the injectors, a clear response to the polymer flooding could be observed very early on. In the beginning the measured data matched very well with the data predicted for water flooding. A decrease in water cut
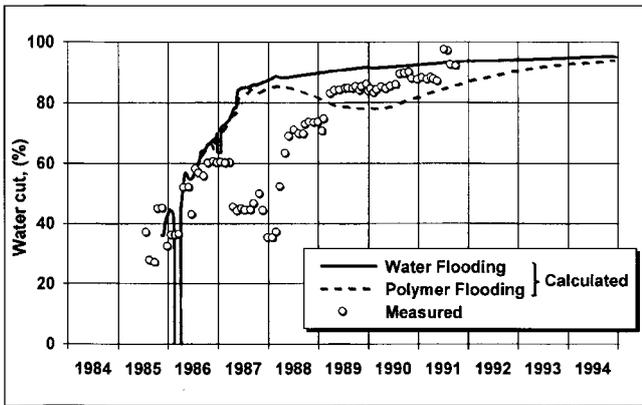
Fig. 5: Response of well 96 to polymer injection - Eddesse-Nord.

Abb. 5: Reaktion auf die Polymerinjektion in der Bohrung 96 - in Eddesse-Nord.

Fig. 7: Response to polymer flooding in well 9 - Adorf.

Abb. 7: Reaktion auf das Polymerfluten in Bohrung 9 - Adorf.

to 30 - 40 % could be observed in 1987, when the water cut predicted for water flooding should be around 90 %.

A similar behaviour could be observed for well 86. This well was recompleted into another production zone at the end of 1988.

The simulation further showed, that about 50 % of the injected polymer was lost into the aquifer and therefore only a slug of about 35 % of hydrocarbon filled pore volume was active in the project for displacing the oil. Hence the observed effect in incremental oil recovery is remarkable. Up to the end of 1991 10 850 m³ oil had already been produced, which is more than that what was predicted to be the ultimate recovery for water flooding.

The field results are compared with the predictions for water and polymer flooding. The simulation runs were performed until 1996 using the actual production rates and for further predictions the last actual production rates in the field. As can be seen from Figure 6 cumulative production in the polymer flood is already higher than what may be extrapolated for water flooding. The actual field performance of the polymer flood is also better than the polymer prediction by numerical reservoir simulation. The incremental production by polymer flooding as compared to water injection is between 1000 and 1500 m³, which is 5 - 7 % of the original oil in place [3].

4.2 Adorf

In Figure 7 the response to polymer flooding in well 9 is shown.

The Figure shows the decrease in salinity and the polymer production. The polymer concentration in the produced water comes up to 1200 ppm (referred to emulsion) or 400 ppm active, which equals 50 % of the injected concentration. Considering dispersion and the salinity development, this means that the adsorption of the polymer is relatively low.

A decrease in water cut also was observed, but it was much lower than predicted by simulation.

The technical performance of the project was very good, no problems occurred, neither in polymer mixing nor in injection. Adsorption of the polymer was low, and an analysis of the produced polymer had shown, that the degree of hydrolysis had increased from 30 % to about 50 %, but the polymer was not degraded at all with respect to molecular weight.

The main reason for the poor response can be seen in the fact, that the polymer solution did not have the expected viscosity under reservoir conditions.

In Figure 8 flow curves of polyacrylamide solutions in different mixing waters are shown. Flow curve 1 corresponds to the mixing water used in Adorf. It is obvious that such a solution is very sensitive to only small changes in hardness.

Fig 6: Project performance - Eddesse-Nord. Oil cut vs. cumulative oil production (total block).

Abb. 6: Ölanteil vs. kummulative Ölproduktion (Gesamtblock) - Eddesse-Nord.
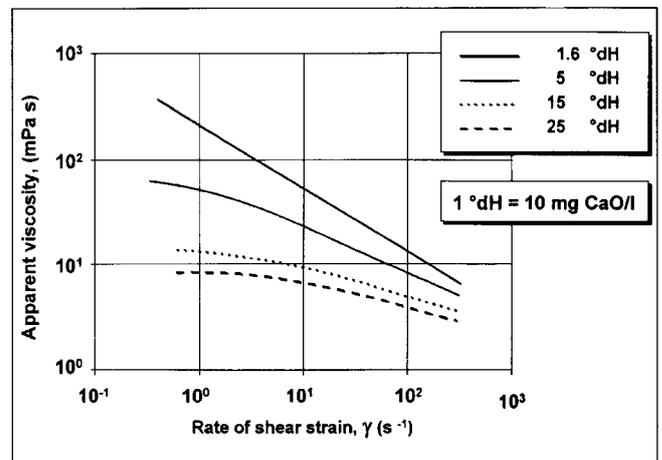
Fig. 8. Flow curves of a solution of 1000 ppm polyacrylamide at different hardnesses of mixing water: 1) 1.6 °dH; 2) 5 °dH; 3) 15 °dH; 4) 25 °dH. (1 °dH = 10 mg CaO/l) [6].

Abb. 8: Fließkurven einer Lösung mit 1000 ppm Polyacrylamide bei unterschiedlichen Wasserhärten.

Calculations and laboratory test performed later showed, that a fresh water being in contact with the minerals in the reservoir should at least have a hardness of 10. This means, according to Figure 8, that the viscosity of the polymer solution would only be about 20 % of that one injected at a hardness of 1.6 °dH.

This was also found by producing back the polymer solution from the injection well. Table 1 shows the volume produced and the corresponding hardness and viscosity of the polymer solution.

cum. produced m^3	hardness °dH	viscosity at 7 $^{S-1}$ mPas
0	1.6	20
22	6.1	4.0
500	8.4	4.7
1315	11.2	4.1
1702	11.0	4.0

Tab. 1: Back-production from well 10-Adorf.

Tab. 1: Rückgewinnung der Polymerlösung aus Bohrung 10 - Adorf.

These results show, that even when the reservoir brine was displaced effectively, the mineralogy of the reservoir would very quickly bring the hardness to a value of about 10 and thus reduce the viscosity of the polymer solution significantly. A viscosity of about 4 of the polymer solution would explain the lower incremental recovery.

4.3 Vorhop-Knesebeck

In Figure 9 the simulated water cut and the values from the field are plotted for well 45. This well is the nearest to the injection well and therefore had a very early response. 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. 10: Oil cut in well 45 as measured in the Preussag laboratory.

Abb. 10: Ölgehalt in Bohrung 45, gemessen im Preussag-Labor.

In the data measured in the field 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 %.

In Figure 10 the oil cuts produced in well 45 are plotted as measured in the Preussag main 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. 11). The best fit is obtained with an adsorption of

Fig. 9: Water cut of well 45. Simulation and measured field data - Vorhop-Knesebeck.

Abb. 9: Verwässerungsgrad der Bohrung 45. Simulation und gemessene Felddaten - Vorhop-Knesebeck.
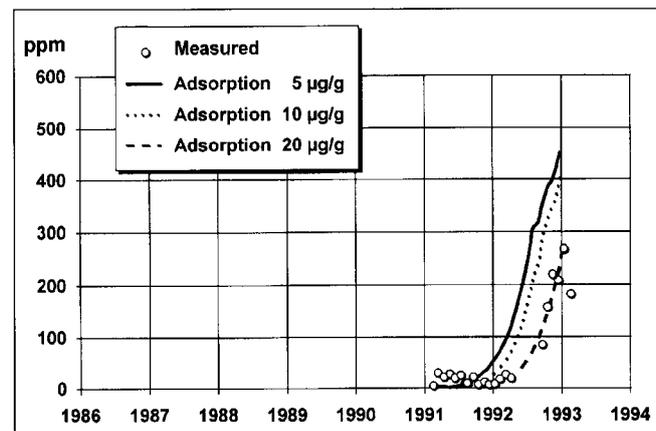
Fig. 11: Polymer concentration in production well 45, measured and simulated.

Abb. 11: Polymer-Konzentration in Produktionsbohrung 45; gemessen und simuliert.

20 μg/g, what is relatively small as compared to laboratory data from literature [6].

The concentration of xanthan may also be determined by viscosity measurement of the produced water, if the concentration is sufficiently high. In Table 9 values measured at samples from wells 8 and 45 are listed. The concentrations are determined by using a calibration curve.

Date	Viscosity	Xanthan concentration
	mPas@20°C	ppm
injected	6.7	400
24.11.92	2.98	160
01.12.92	2.96	160
11.12.92	3.30	200
18.12.92	3.40	200

Tab. 2: Viscosities of produced water from well 45 - Vorhop-Knesebeck.

Tab. 2: Viskosität des produzierten Lagerstättenwassers aus Bohrung 45 - Vorhop-Knesebeck.

The total performance of the project in terms of incremental oil recovery was not as good as expected. The main reason was that the description of the reservoir had to be changed during the project. This resulted in a higher oil recovery during water flood, so that the amount of oil, that was produced incrementally during the project could not totally be credited to the polymer flooding. The incremental oil recovery, that can be calculated so far is about 3 % of the OOIP. In total the project can be regarded as technical successful especially to the fact, that polymer adsorption of about 20 μg/g is much lower than expected from laboratory measurement (at least 70 μg/g).

4.4 Scheerhorn

In Figure 12 the response of well 85 is shown. This well shows a clear response to polymer injection, but it was lower than expected. From simulation runs an incremental oil recovery of 15 % was expected for the pilot area, but only 3 % was actually reached.
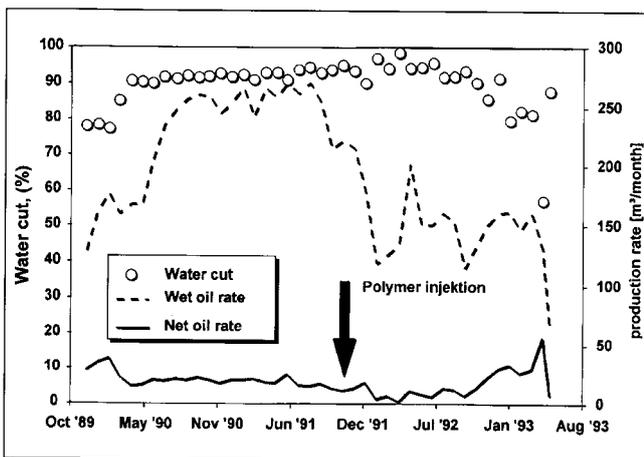
Fig. 12: Response of well 85 to polymer injection - Scheerhorn.

Abb. 12: Reaktion auf die Polymerinjektion in Bohrung 85 - Scheerhorn.

There were two main reasons found for this result. The first is the polymer itself. It was already mentioned, that the xanthan used in this project was substantially different from that one used in the other 2 projects. Due to economical reasons a product with a higher viscosity yield was used. This product did not have the same stability as the others.

This was found in the lab, but also in the field. From the injection well a sample was taken at the well head and afterwards the well was flowing back. About 30 m³ of xanthan solution could be produced from the injection well. In Table 3 the viscosities of these samples are given. A decrease in viscosity could be observed already after a short time, when the polymer had entered the reservoir.

Sample	Viscosity in mPas (50 °C, 3 s^{-1})
Solution at well head	27.2
Solution produced from injection well (after 30 m³)	23.1
Solution from production well 86	8.0

Tab. 3: Viscosities of different polymer samples - Scheerhorn.

Tab. 3: Viskosität verschiedener Proben von Polymerlösungen - Scheerhorn.

The polymer concentration is the same for all samples (800 ppm).

Analysing the produced water from well 86 showed, that the polymer solution had still its full concentration of 800 ppm a short time after polymer break-through. This means, that adsorption in this case is negligible. But the viscosity of the produced xanthan solution was only 8 mPas. This is only one third of the initial viscosity. This would be approximately the same value that could have been achieved with the xanthans used in the other projects. In other words the advantage of the higher viscosity yield of the high pyruvate product was sustained only for a short time.

Another reason for the low incremental oil recovery was found in the reservoir and in its oil. All calculations were made for an oil having a viscosity of 30 mPas at reservoir conditions. This was only true for a short period at the beginning of production. In many parts of the field pressure was reduced to below the bubble point pressure. The production of large amounts of gas and thus the reduction of solved gas in the oil led to an increase in oil viscosity.

Very early in the life of the field water injection had to be started in order to increase reservoir pressure. As the injection water was colder than the reservoir and large amounts of water were injected the reservoir was cooled significantly. It is estimated, that the reservoir was cooled down by about 3 - 5 °C. This again led to an increase in viscosity o the oil. The oil viscosity at present is therefore not 30 mPas but at least 60 to 100.

5. Conclusions

In Table 4 the different reservoir parameters and the results of the projects are shown.

Polymer injection into the reservoirs was no problem at all. Proper mixing of the polymers could be achieved.

The retention of the polymer in the field was significantly lower than measured in the laboratory and published in different papers. This was valid for xanthan and polyacrylamide.

		Eddesse-Nord	Adorf	Vorhop-Knesebeck	Scheerhorn
Formation		Wealden (Sandstone)	Valanginian (Sandstone)	Dogger-ß (Sandstone)	Valanginian (Sandstone)
Depth	m	290	1350	1250	1050
Temperature	°C	22	68	56	49
init. reservoir pressure	bar	24	133	130	116
Porosity	%	22	25	27	26
Permeability	mD	600	2000 - 5000	1000	2500
Thickness	m	5	18	14	5 - 12
Oil viscosity (@reservoir conditions)	mPas	7	12.1	3.5	30.8
Dead oil viscosity	mPas	15.6	immovable	19	35 000
init. Salinity of brine	g/L	100	250	210	77
Salinity of injection water	g/L	50	0.112	210	77
Polymer		Xanthan (Bayer)	partially hydrolysed Polyacrylamide	Xanthan (Statoil)	Xanthan (commercial)
Polymer concentration	ppm	1 000	2 400 (emulsion) 800 (active)	400-500	800
Viscosity of polymer solution ($\approx$ 3 s-1) (reservoir conditions)	mPas	7	20	4	30
Total injected polymer	kg	9 450	639 000	59 000	370 000
Pore volume	m^3	27 500	1 10^6	540 000	83 000
OOIP	m^3	21 000	850 000	450 000	60 000
Incremental oil recovery	m^3	1 200	5 900	13 400	2 000
Incremental oil recovery	%OOIP	6	1	3	3.3
Retention/adsorption	µg/g	30 - 40		20	

Tab. 4: Reservoir parameters and performance of the polymer projects.

Tab. 4: Lagerstättenparameter und Ergebnisse der Polymerflutprojekte.

During all the projects the knowledge about the reservoir increased, the reservoir models had to be changed.

In the Vorhop-Knesebeck field oil recovery by water flooding was higher than anticipated at the start of the project. Therefore the oil recovery possible by polymer flooding was lower than expected at the start of the project. This was the main reason, why the project was stopped earlier than planned.

Degradation of the polymers was only small, as observed in the Eddesse-Nord, Vorhop-Knesebeck and Adorf projects. The observed „degradation" in Scheerhorn was not due to bacterial or chemical processes, but to the fact that the polymer was artificially brought to a higher apparent viscosity. The polymer came back to its natural state in the reservoir.

No change in chemical composition of the xanthan was observed for the three years of residence in the reservoir in Eddesse-Nord, where the produced polymer was intensively analysed.

The main reason for the low incremental oil recovery in the Adorf and Scheerhorn projects was, that due to economical constraints, the polymer did not have the viscosity in the reservoir it should have.

In Eddesse-Nord a xanthan degrading species of bacteria, well adapted to the conditions in the oil water separator in the field, could be isolated. However it could not degrade the xanthan significantly during the project period in the reservoir. This is due to the biocide used, the low pH-value and the high salinity in the reservoir.

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