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Experience with Polymer Flooding in High Salinity and Low Viscosity Oil Reservoirs

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Abstract

Basic mechanisms of polymer flooding are discussed and laboratory methods for polymer screening are presented. For the polysacharide xanthan the requirements for mixing in the oil field and injection are given.

Two polymer flood projects using xanthan have been performed. One of these projects has been terminated successfully, the other is injecting for half a year.

It is concluded that polymer flooding using xanthan is feasible in high salinity reservoirs with temperatures up to 60 °C and more, that no injectivity problems occur, polymer adsorption is low and long term stability of the polymer is not a problem. The incremental oil recovery even in reservoirs having relatively low oil viscosities (3 - 10 mPa·s) is in the range of 5 - 10 % OOIP, so that the process will also be economic.

1. Introduction

The situation in West Germany's oil fields is characterized by increasing water cuts. The mean water cut is 75 % and in some oil fields up to 97 %, which is very close to the economic limit. So Enhanced Oil Recovery is of major concern in petroleum related research in West Germany.
Besides steam flooding which is being applied in several fields with heavy oils CO_2-flooding, surfactant flooding and polymer flooding were subject of research in the oil companies as well as at universities and the petroleum institutes. Many of this research was supported by the German government. For the oil fields Preussag is operating it has turned out that only polymer flooding is technical and economical feasible. With polymer flooding Preussag's reserves in oil fields with oil viscosities between 15 and 50 mPa·s under reservoir conditions could be doubled.

Reservoirs with oil viscosities under reservoir conditions between 3 and 10 mPa·s are thought to be more suitable for surfactant flooding than for polymer flooding. Nevertheless we started polymer flooding in these types of reservoirs due to two reasons which are first, that polymer flooding is an essential part of a surfactant flood and so before a surfactant flood can be started the know how for polymer flooding has to be developed and second that we think that also under conditions where water flooding already leads to a good recovery also with polymer incremental oil can be produced economically.

2. Theory of Polymer Flooding

Polymer flooding improves the sweep efficiency in a petroleum reservoir and thus leads to an incremental oil recovery. The improvement in sweep efficiency is contributed by an improvement in vertical sweep efficiency, which means that due to the non-Newtonian flow behavior of a polymer solution a more uniform injection profile may be achieved. Furthermore the areal sweep efficiency is improved due to the more favourable mobility ratio between the displaced oil and the displacing water phase. The microscopic sweep efficiency is also improved by the better mobility ratio (LITTMANN 1988) as can be shown using the fractional flow concept.

Polymer flooding is usually implemented where the recovery by water flooding is only poor, which is the case in reservoirs with high viscosity oils where steam flooding is not yet applicable or in very heterogeneous reservoirs where water early breaks through in high permeable zones.

Though it is the common meaning that by polymer flooding only the same amount of oil can be produced as in a long water flood there are indications that this is not true, as e.g. the incremental oil recovery by polymer flooding in a field project in France could only be described in numerical reservoir simulation by decreasing the residual oil saturation (PUTZ 1988).

There is no doubt that polymer flooding accelerates oil production significantly, as will be shown later. This alone may be a reason to consider polymer flooding e.g. for the North Sea where time is an important economic factor (THOMASSEN 1987).

3. Polymer Requirements

Most of the oil reservoirs in West Germany have high salinity reservoir waters. As these waters are also produced with the oil and have to be reinjected and therefore have to be used as mixing waters it is obvious that for polymer flooding only salt water stable polymers can be used. Polymer flooding using polyacrylamide in fresh water is only applicable in few reservoirs where a preconditioning of the reservoir with fresh water is possible (MAITIN 1985). A pilot project using polyacrylamide in one oil field where Preussag participates failed, because the necessary preconditioning failed in that very heterogeneous reservoir and so the viscosity of the polymer solution under reservoir conditions was not high enough.

These are the main reasons why xanthan was choosen for polymer flooding. Xanthan is an extracellular polysaccharide produced by the bacterium *xanthomonas campestris*. The structure of xanthan is shown in Fig. 1 (MOORHOUSE 1977) The cellulose backbone has two different side chains made up of three monosaccharides. These side chains give the molecule its strength against mechanical degradation. The side chains bear electrical charged groups which are glucoronic acid, acetate, and at the last sugar a pyruvate group. Mainly the pyruvate group is statistically distributed. The content of these groups in the molecule and here mainly the pyruvate determines the solubility and solution properties of this polymer. A low pyruvate content decreases solubility, whereas a high pyruvate content increases the tendency to form aggregates (KLEINITZ 1989). These electrical charges at the molecule also influence its adsorption behaviour and long term stability (LUND 1990).

3.1 Injectability of polymer solutions

The injectability of a polymer solution through a well bore into a reservoir is an important prerequisite for polymer flooding. To achieve this the mixing water in the field has to fulfill certain requirements as well as the polymer itself and the condition of the injection well.

3.1.1 Water quality and water treatment for polymer flooding

The water quality necessary for a polymer flood project depends on the characteristics of the reservoir rock. Based on the theory of Barkman and Davidson (BARKMAN 1972) a continously working detection system was developed to determine water quality in an oil field. Here not the residual oil concentration or the content of dispersed solids is determined, but the permeability of a filter cake that builds up during the filtration through a filter membrane of constant pore size (DIETZEL 1989). The water quality ratio is measured in ppm/mD. For the Eddesse-Nord project the specification was 7 - 20 ppm/mD (0.8 μm filter) and 15 - 30 ppm/mD (0.8 μm) for Vorhop-Knesebeck respectively.

The water treatment in the Eddesse-Nord project was done by adjusting the pH at 5.2 at a residual oxygen concentration of 10 - 20 ppb. To reduce dispersed unsoluble fine particles a walnut shell filter (Hydromation) was used which was backflushed every 24 hours. Citric acid was added to sequester Fe^{3+}-ions. Formaldehyde was added as a biocide.

The pipe system for water is in most of our oil fields made of GRP or polyethylene or coated carbon steel pipes to exclude corrosion.

The basic principles in water treatment are: constant flow conditions and a minimum of chemicals to be added.

3.1.2 Injectability testing

To test the injectability of a polymer solution it is injected into a sand pack. The pressure drop over the sand pack is recorded during the injectability test where about 200 pore volumes are injected in 15 -18 h.

The sand pack is made up of a broken quartz sand with a grain size of 63 - 90 μm. The length of the sand pack is 4 cm the diameter 1.9 cm. With these sand packs porosities of 50 - 55 % and permeabilities of 2000 - 3000 md are obtained.

The ideal polymer solution is that where the pressure does not increase during the test. The specification for polymer solutions to be used in the field tests was that the pressure increase Δp between 1h and 15h of injection was below 20 % for the Eddesse pilot and 30 % for Vorhop-Knesebeck. The residual resistance factor should be below 2 for Eddesse-Nord and below 3 for Vorhop-Knesebeck.

3.1.3 Preparation of injection wells

The injectivity of an injection well in polymer flooding is more critical than in water flooding, as the injection pressure of the polymer solution is much higher than in water flooding due to the higher viscosity of the polymer solution. Because of the non-Newtonian flow behavior of the polymer solution the viscosity is lower around the injection well where high shear rates are present than in the reservoir. But this is often compensated by the effect that the reservoir is cooled down due to the injection of cold liquid which leads to an increase of the viscosity of the polymer solution.

In case of the Eddesse-Nord polymer pilot pressure fall off tests showed a skin and bad injectivity of one well. A casing inspection log (multi-finger-caliper) showed that only few of the perforations were still open. After a re-perforation of the well with a 5" high density TCP-gun a good injectivity was obtained and no problems were encountered during the whole project. Fig. 2 shows the

CIL before and after re-perforation of the well.

The same experience was gained in the Vorhop-Knesebeck project.

Furtheron small fracture-jobs may be utilized to improve the injectivity as well as underreaming and gravel packing.

3.2 Polymer mixing in the field

The principle of polymer mixing in the field is shown in Fig. 3. The xanthan broth is stored in a 40 m^3 stainless steel tank (Eddesse-Nord) or in a 23 m^3 tank container (Vorhop-Knesebeck) which was also used for shipping.

Before the polymer is mixed to the water formaldehyde is added at a concentration of 1000 - 2000 ppm, citric acid at a concentration of 50 - 80 ppm to sequester the iron (30 ppm Eddesse-Nord, 50 ppm Vorhop-Knesebeck), and the pH-value of the water is adjusted to 5.2 using hydrochloric acid.

The xanthan broth is metered to the water by means of a rotating piston pump. Before the polymer is mixed with the water in a small mixing chamber it is sheared by passing through a 20 μm filter. The polymer solution passes a static mixer and is afterwards sheared in a in a dynamic mixer (ultra turrax). This polymer solution is then flowing to the injection wells.

4. Results of Field Projects

4.1 Eddesse-Nord

4.1.1 Reservoir description

The Eddesse-Nord oilfield is located in northwest Germany. It was discovered in 1950 at the northern flank of a salt dome. Oil production comes from three separated main parts of the reservoir. Pay zones are Valangenian and Wealden sandstones and Liassic and Rhaetian sandstones. The initial oil in place was $1.68 \cdot 10^6$ t. Cumulative oil production is 775 000 t, the average water cut is 90 %.

A polymer pilot flood was started in this field in November 1984 (LITTMANN 1987).

For this pilot one layer in the reservoir was chosen (layer M) which was seperated from the other oil bearing zones by impermeable clay layers. A type log and a structure map of top layer M are given in Fig. 4 and 5.

The layer M may be devided into layers of different properties. The upper layer has an average thickness of 2m an average porosity of 26 % and an average permeability of 1700 mD. The values for the lower layer are h = 3m, ø = 22 % and k = 900 mD. Pressure fall off tests in the injection wells and the results of the numerical reservoir simulation gave evidence that these permeabilities were too high and that values of 1000 mD in the upper layer and 500 mD absolute permeability were more realistic. This also takes into account that the reservoir sand was not clean, but shaly and silty with significant amounts of clay mineral as kaolinite.

The hydrocarbon saturated pore volume was 27 500 m^3 and the initial oil in place 21 200 m^3 under reservoir conditions. The reservoir temperature was 22 °C and the oil viscosity under reservoir conditons 7 mPa·s.

In primary and secondary operations oil was produced only in well 90, which was due to the downdip position of this well not optimal. Only during a short period water was injected in well 91. During primary production the reservoir pressure fell below the bubble point and a secondary gas cap developed in the updip 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. Cumulative production in 1984 was 7085 m^3 tank oil.

For the polymer flood project well 96 was drilled in the updip part of the reservoir. The well was cored in the entire pay zone to get fresh and representative core material for laboratory investigations.

4.1.2 Polymer injection

Before polymer injection was started a water preflush of 10 300 m^3 was injected into well 91 to repressurize the reservoir and thus reduce the secondary gas cap and to get data of the water flood performance of the selected flood concept.

A Xanthan polymer solution of 800 - 1000 ppm of active xanthan was injected into wells 90 and 91 at a rate of 10 - 12 m^3 /d in each well. The viscosity of the polymer solution was 12 - 16 mPa·s at a shear rate of 7 s^{-1}. The injection well head pressure was 15 - 20 bar in well 90 and about 10 bar in well 91. During the whole injection period (Nov. 85 - May 88) no injectivity problems occured.

The xanthan used came directly from the fermenter with all the dead bacteria in it. The only preparation was that it was preserved with formaldehyde against bacterial growth. Every produced xanthan batch was tested in our laboratory as well as in the lab of the producer (Bayer AG Wuppertal) for injectability into a sand pack and for filterability through a 3 µm filter. The specification for the polymer to be used in the project was to pass the filterability test with a pressure increase below 20 %. The specification for the filtration test was that the ratio of the filtration rates after 100 ml 900 ml were filtered was below 10.

Fig. 6 shows a correlation between the sand pack tests performed in the two labs including the specification range. This graph shows a very good correlation between the tests and that only one batch had to be rejected. Fig. 7 shows that there was no correlation between the filtration test and the injectability test into a sand pack. The filtration test was therefore not used as a criterion for the polymer quality.

4.1.3 Production

Production in well 96 was started in March 1985. After producing 1200 m^3 (V_n) of gas the well could be produced at a rate of 0.5 m^3/d at zero water cut. The production rate could soon be increased to 3 - 4 m^3/d. As this production rate was relatively low (25 % of the injection rate) and a further acceleration was not possible the additional well 88 was put in production from sand M in May 1986 followed by well 86 in March 1987.

Fig. 8 - 10 show the water cut development of these three wells together with the results of numerical reservoir simulations for water flooding and polymer flooding.

Though well 96 is the most distant from the injectors a clear response to polymer flooding could be observed very early. In the beginning the measured data match very well with the data predicted for water flooding and polymer flooding. A decrease in water cut down to 30 - 40 % could be observed in 1987 when the water cut predicted for water flooding should be around 90 %.

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

The water cut development of well 88 is shown in Fig. 9. This well is located at only a distance of 60 m from the injection well 90 and so a breakthrough of the chemicals injected could be observed very early. For this well the agreement between the prediction of the water cut development determined in numerical reservoir simulation with the values measured in the field is also very good. This gives evidence that the values used as input in the simulation for adsorption and dispersion are reliable.

At this point it is important to know that the xanthan was mixed and injected in a water of a salinity of 50 g/l, whereas the original salinity in this part if the field was 120 g/l. Along with the polymer formaldehyde was injected at a mean concentration of 2000 ppm. Salinity development, polymer adsorption and adsorption or loss of the formaldehyde were also calculated in a simulation model. Fig. 11 shows the calculated and measured values for salt formaldehyde and xanthan as produced in well 88. A good agreement between simulation and field data has been achieved assuming a polymer adsorption of 30 μg/g of reservoir rock and 15 μg/g for the formaldehyde.

After polymer breakthrough in well 88 sample were taken from the well and analyzed for the quality of the produced polymer. Fig. 12 shows flow curves of the produced polymer solution as it came from the well and after filtration. These flow curves are compared with one of a fresh polymer solution of the same concentration. From this comparison it may be derived that the polymer produced was not degraded. Determination of the molecular weight using size exclusion chromatography (SEC) and low angle laser light scattering (LALLS) showed that the molecular weight was $9.3 \cdot 10^6$ g/mole for the fresh xanthan and $9.5 \cdot 10^6$ g/mole for the produced xanthan after a residence time of about 3 years in the reservoir. The poly dispersity index (PDI) was 1.39 for the fresh sample and 1.22 for the produced sample. From the PDI and the flow curve it may be concluded that the polymer quality even improved slightly due to some filtration in the reservoir. During the whole production phase no bacterial activity or H_2S in the gas or water phase was detected.

The simulation further showed that 50 % of the injected polymer was lost in the aquifer, so that only a slug of 20 % of the hydrocarbon filled pore volume was active in the polymer flood to displace oil. So the effect on incremental oil recovery is remarkable. By the end of 1989 already 10 500 m^3 oil could be produced which is the amount of oil that was predicted as ultimate recovery for water flooding. As the wells 88 and 96 are still producing it is no doubt that the goal if 12 000 m^3 cumulative oil recovery will be reached in about 1994 as predicted.

So it can be concluded that in the project an incremental oil recovery of about 6 % OOIP is possible and that oil production is accelerated significantly.

4.2 Vorhop-Knesebeck

4.2.1 Reservoir description

The Vorhop-Knesebeck oil field is located in North-West Germany. For a polymer pilot project in this field a closed block was choosen. The structure map of this block is shown in Fig. 13. The net pay thickness of the upper layer where the polymer flood is being performed is 8 - 14 m, the porosity is 27 % and the average absolute permeability is 1000 mD. The total pore volume is 430 000 m^3. The salinity of the formation water is 210 g/l TDS, the reservoir temperature 56 °C and the oil viscosity under reservoir conditions is 4 mPa·s.

Four wells have been drilled in this block, two updip (8 and 48) and two downdip wells, where 45 is a producer and H3a was drilled as a water injection well.

The primary production phase was short and only 85 000 t could be produced, as due to the fact that the block is closed the bubble point pressure was reached soon.

Water injection in well H3a was started in December 1986 so that the reservoir pressure increased again.

A numerical reservoir simulation study was performed (GERKEN 1988) to compare water flooding and polymer flooding. The incremental oil that could be recovered by polymer flooding was calculated to be about 8 % OOIP.

4.2.2 Polymer injection

The polymer flood project was devided into two phases, where in phase I polymer is injected only in well H3a until polymer breaks through in well 45. This phase is estimated to last about 22 month. The injection rate is 120 m^3/d. After phase I is finished a decision can be made to continue the project or not.

Phase II will be started after a clear respose on polymer injection has been detected in well 45 , i.e. a decrease in water cut and polymer breakthrough. In phase II polymer will be injected into well H3a and 45 at an injection rate of 80 m^3/d into each well.

The polymer is a xanthan broth of an active content of about 3.5 %. The pyruvate content is about 2 - 3 %, so that this product is very similar to that one used in the Eddesse-Nord pilot. The product is produced in a pilot fermentation plant in Stavanger (Norway) by STATOIL. The polymer is shipped in 23 m^3 stainless steel tank containers. These containers are also used for storage in the field. The polymer is directly mixed with the field water in a mixing plant as described above.

Also in this project no injection problems were encountered up to now. In Fig. 14 the development of the well head injection pressure is shown and compared with calculated values. Temperature effects and and "shear thinning" of the polymer solution were considered in this calculation. The calculation was made assuming a radial symmetry around the injection well, what is not quite true. Nevertheless a good agreement between calculated and measured values was achieved. The essential results are that this agreement was obtained using a permeability to water of 180 mD and of course that the injection pressure stabilized after a short time.

4.2.3 Production

The oil is produced from wells 8 and 48, well 8 at a rate of 40 m^3/d and well 48 at a rate of 120 m^3/d. The different production rates are applied to move the polymer slug as uniform as possible through the reservoir and to avoid a direct flow from well H3a to well 8. Well 45 is produced at a rate of about 3 m^3/d. This well is used as a control well during phase I, water cut in this well was already 100 % at the beginning of the polymer injection.

In Fig. 15 - 17 the water cut development of the three production wells is shown together with values calculated in numerical reservoir simulation. A good agreement was achieved between reservoir simulation and measured values for wells 45 and 8. For well 48 still some matching is necessary what is being done.

5. Conclusions

From the pilot project Eddesse-Nord, and the preparation and so far gained experience from polymer injection in the Vorhop-Knesebeck field it may be concluded that polymer solutions that fulfil the specifications as tested in the lab no problems will occur during injection in the oil field, if the quality of the injection water is good and the injection wells are prepared well. Adsorption and long term stability of xanthan is found to be no problem. Also in cases where oil recovery by water flooding is already high incremental oil may be recovered by polymer flooding.

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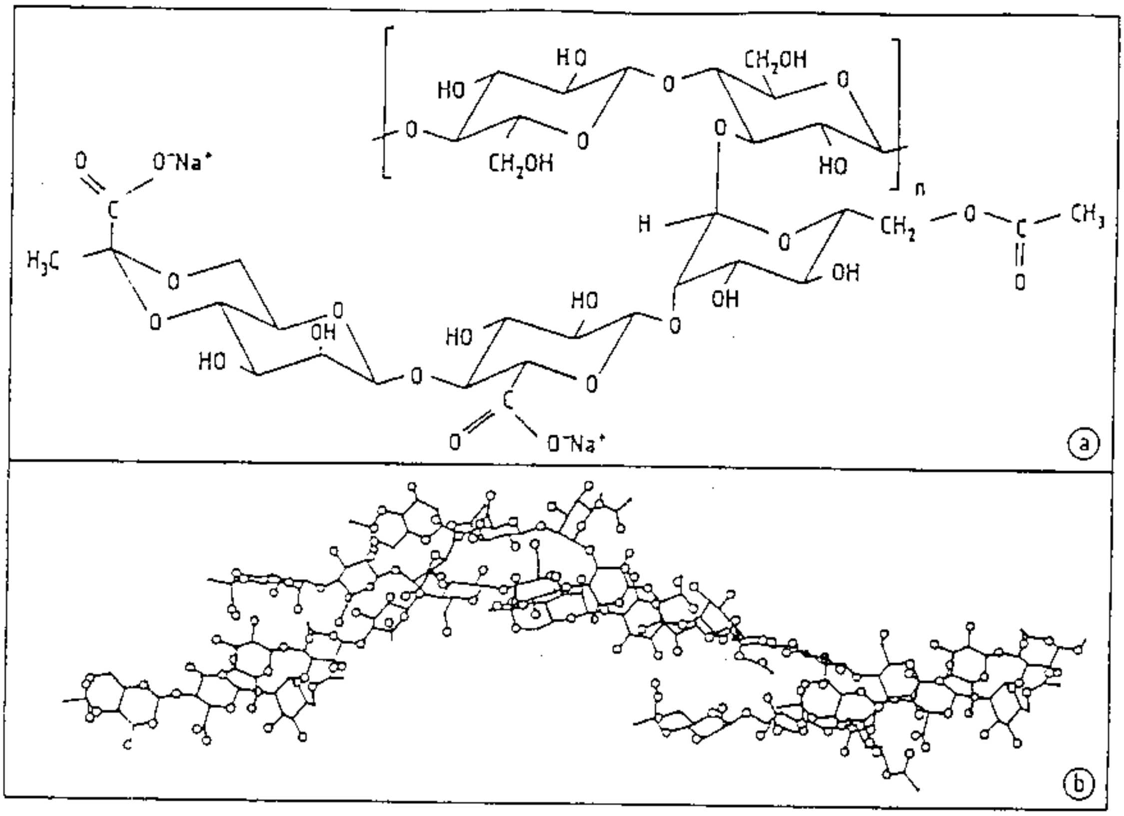


Fig. 1: *Structure of the xanthan molecule. a) chemical structure b) steric structure*

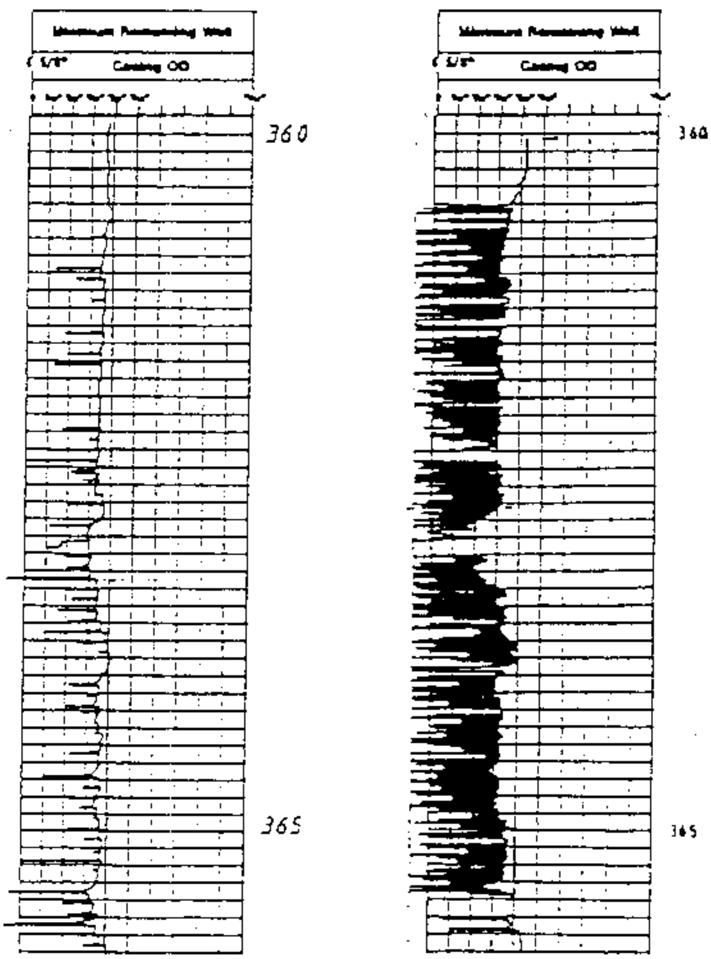


Fig. 2: *Polymer project Eddesse-Nord. Casing Inspection Log in well 97 before and after reperforation*

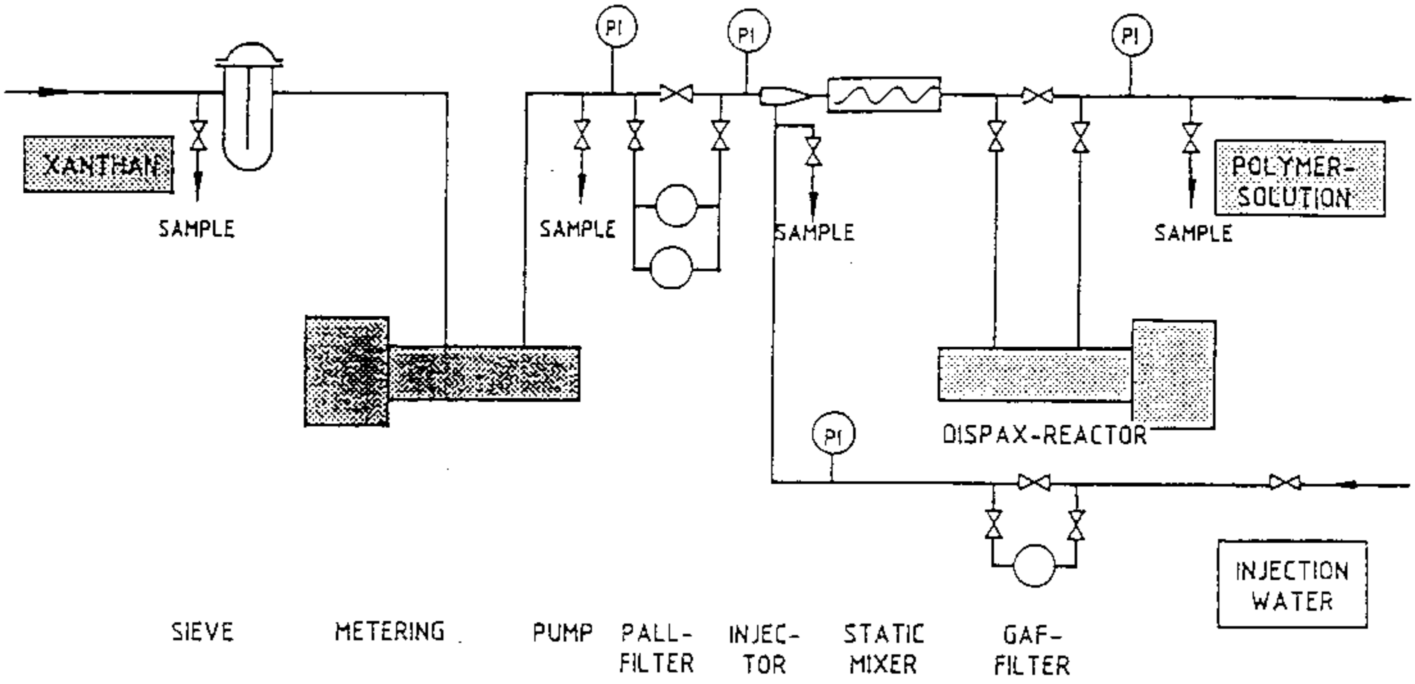
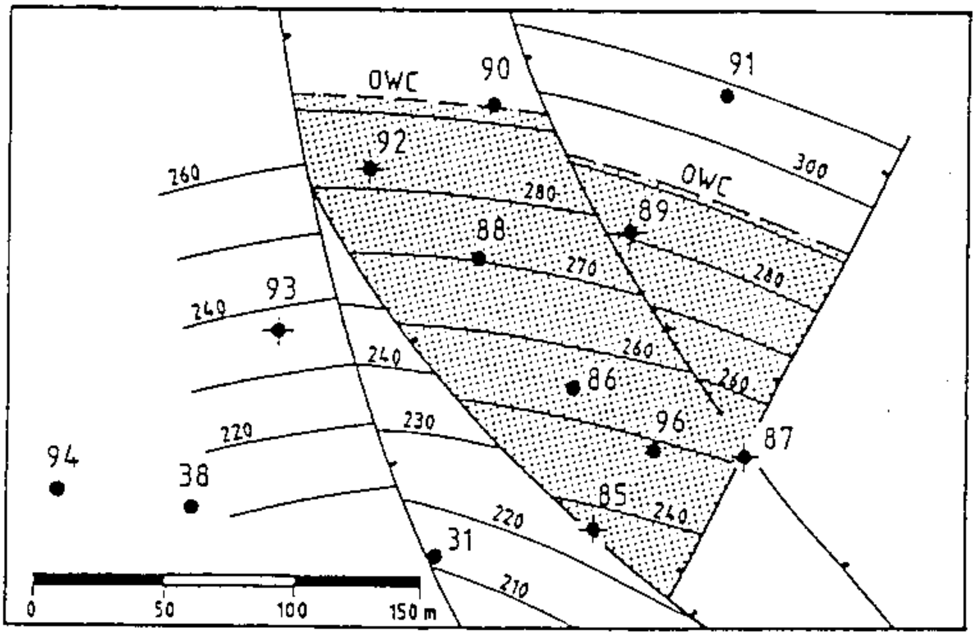


Fig. 3: *Principle of mixing plant for xanthan broth*



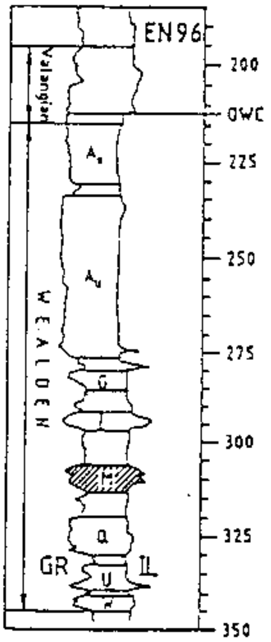


Fig. 4: *Polymer project Eddesse-Nord. Structure map top M-sand*

Fig. 5: *Polymer project Eddes*
Nord. Type log of we
96

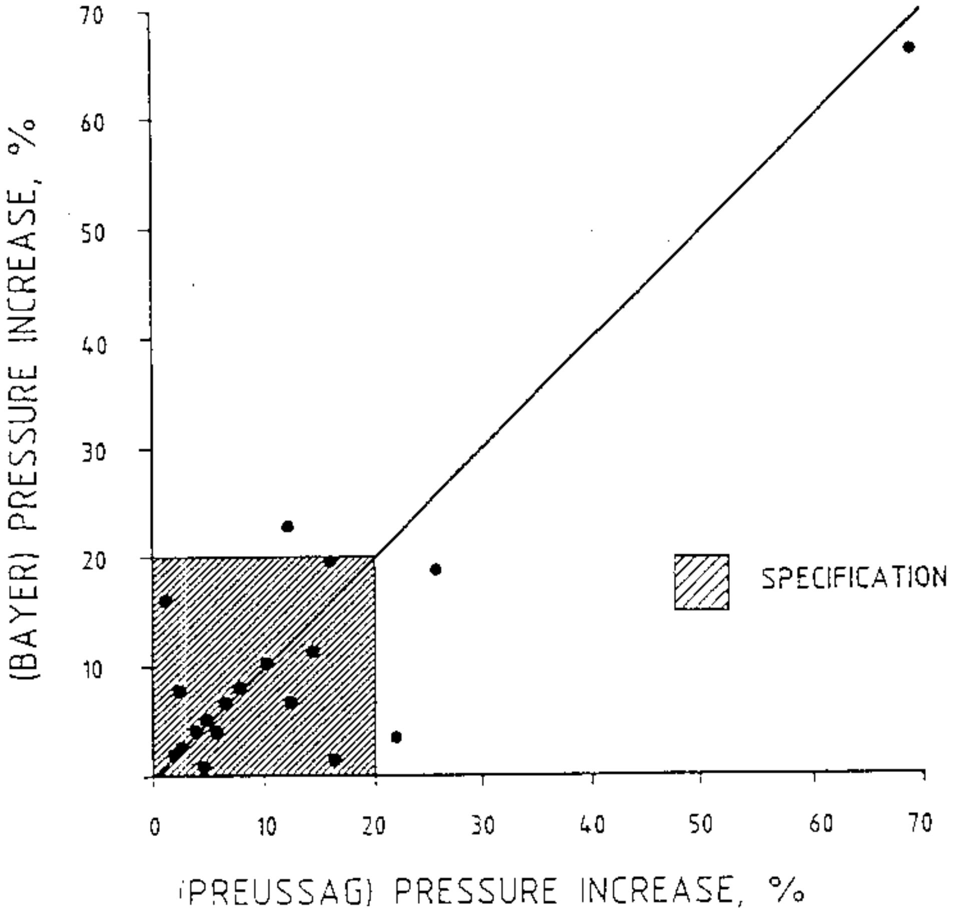


Fig. 6: *Polymer project Eddesse-Nord. Correlation of sand pack injectability tests on different xanthan samples performed in two different laboratories*

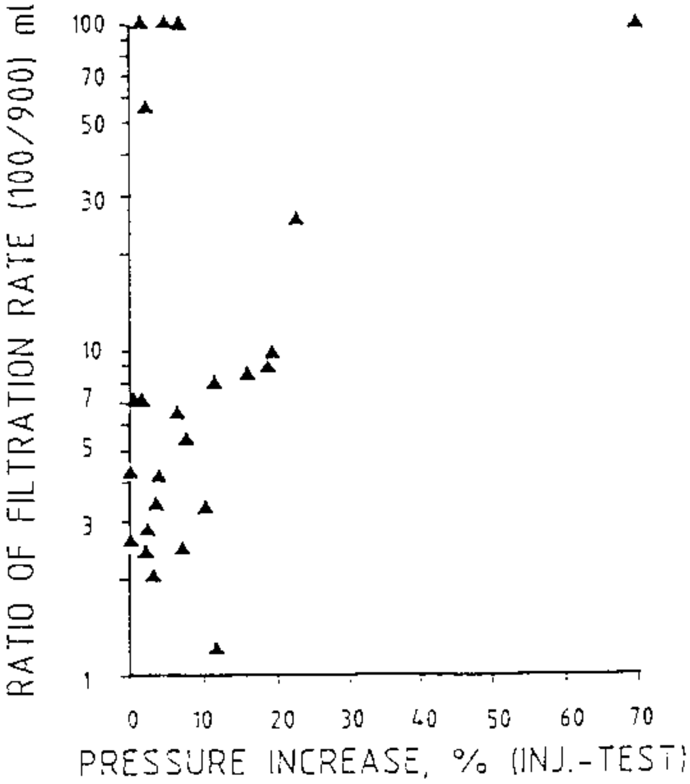


Fig. 7: *Polymer project Eddesse-Nord. Correlation of sand pack injectability tests and filtration tests*

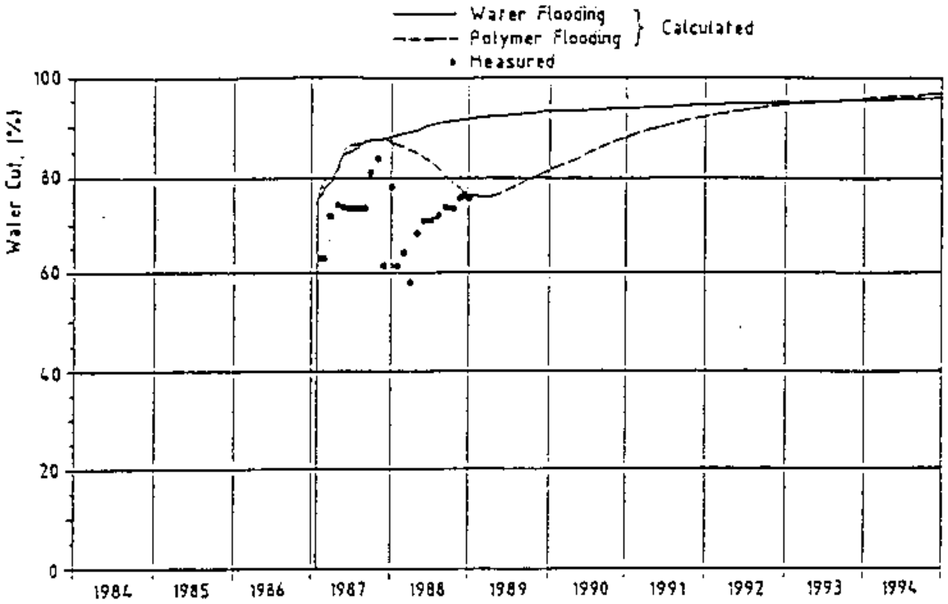


Fig. 8: *Polymer project Eddesse-Nord. Water cut of well 86*

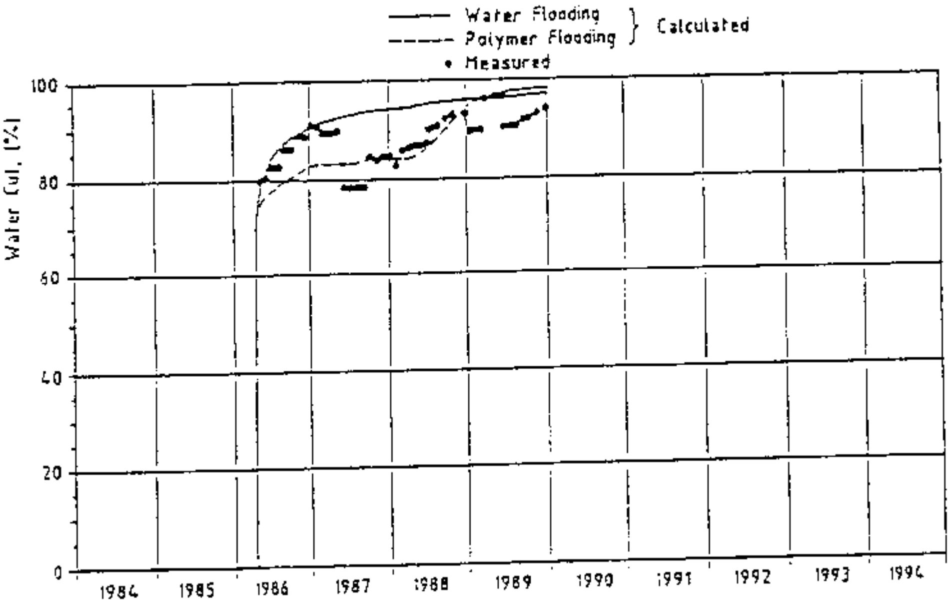


Fig. 9: *Polymer project Eddesse-Nord. Water cut of well 88*

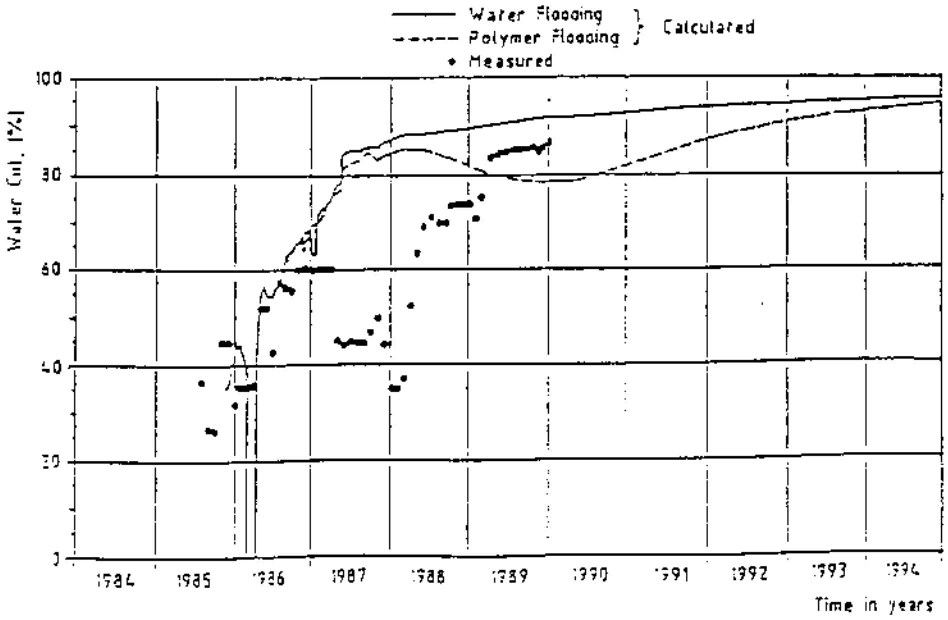
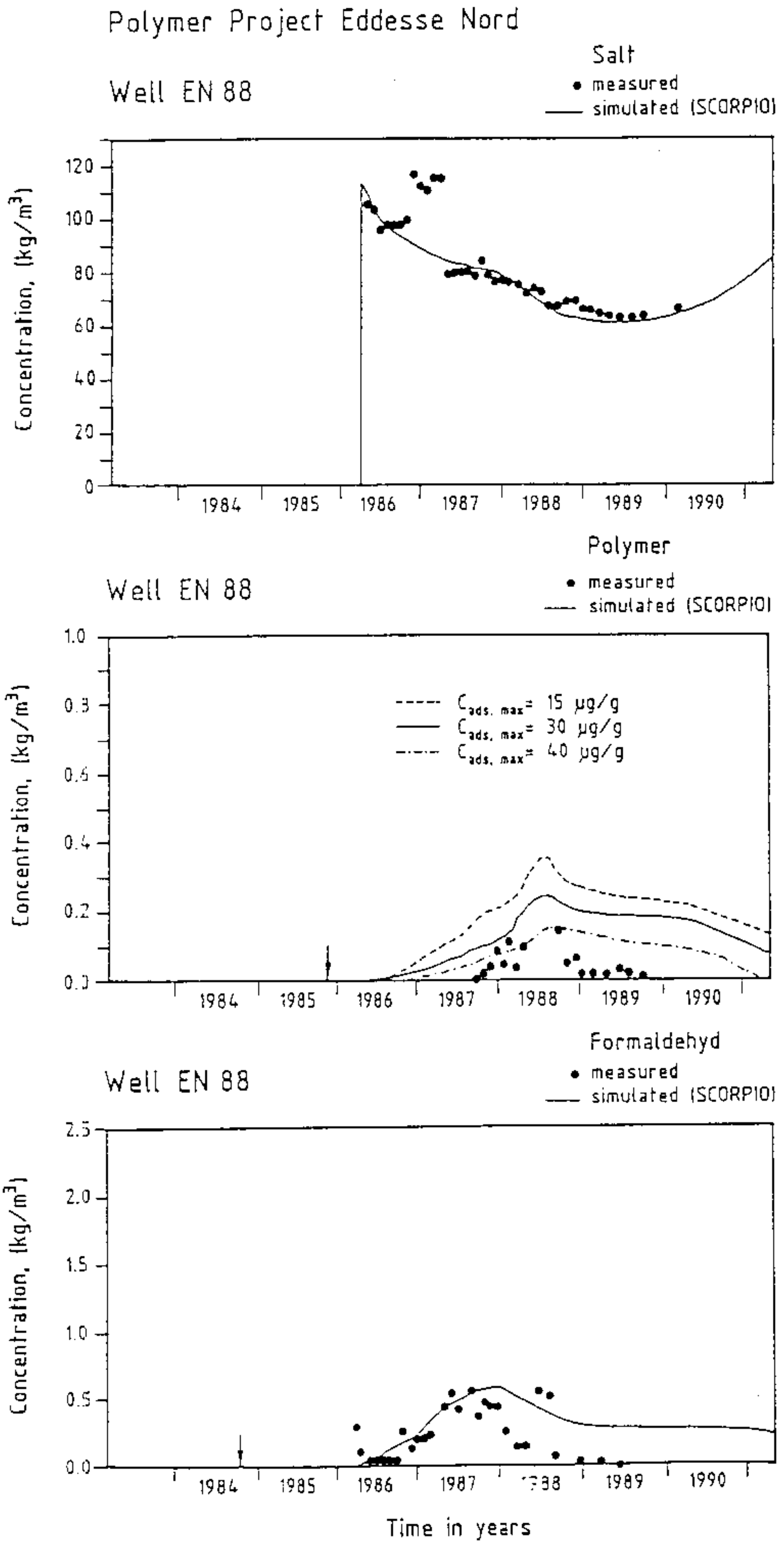
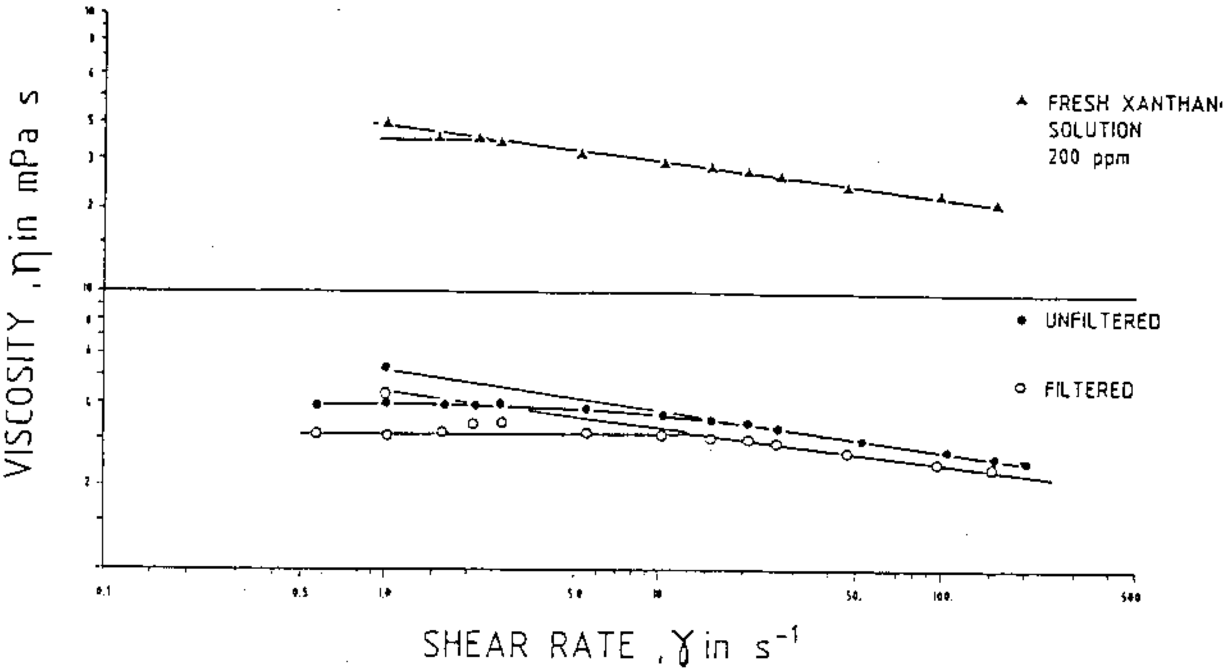


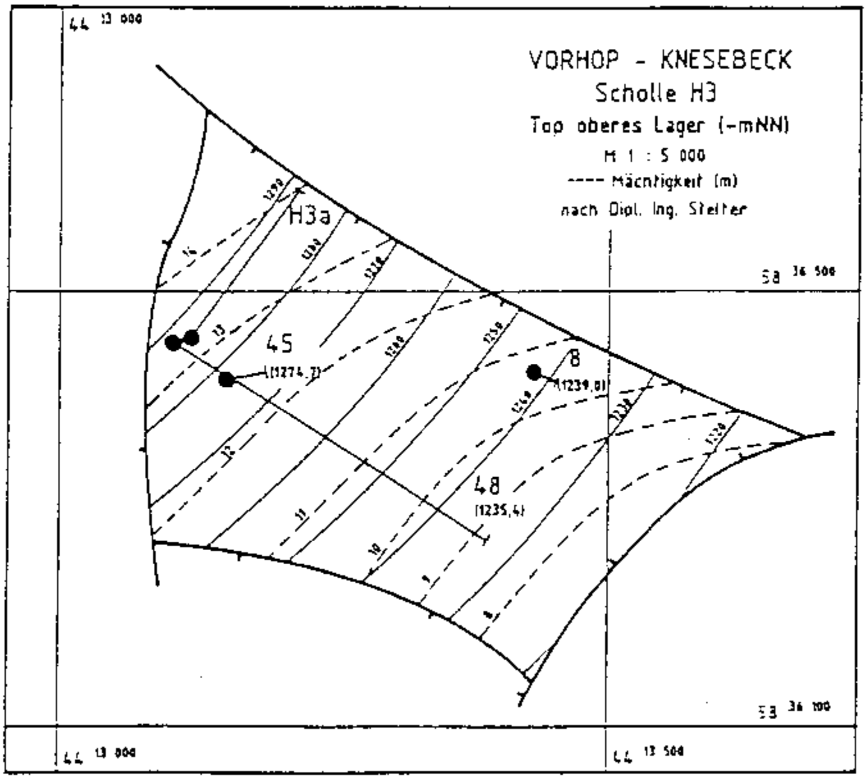
Fig. 10: *Polymer project Eddesse-Nord. Water cut of well 96*



<u>Fig. 11:</u> *Polymer project Eddesse-Nord. Measured and calculated concentrations of salt, formaldehyde and xanthan*



<u>Fig. 12:</u> *Polymer project Eddesse-Nord. Flow curves of produced xanthan from well 88 compared with a fresh polymer solution of same concentration*



<u>Fig. 13:</u> *Polymer project Vorhop-Knesebeck. Structure map of pilot area*

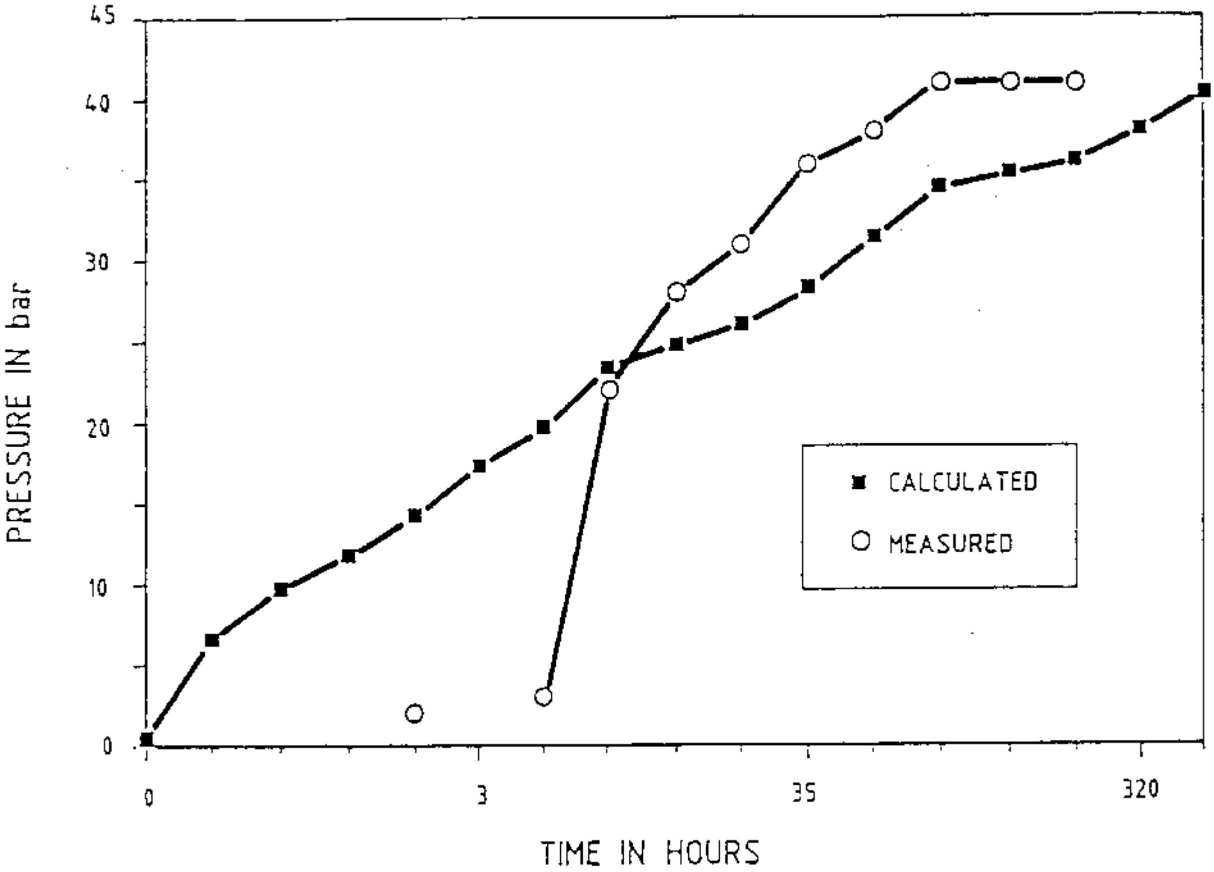


Fig. 14: *Polymer project Vorhop-Knesebeck. Measured and calculated injection well head pressure of well H3a during polymer injection*

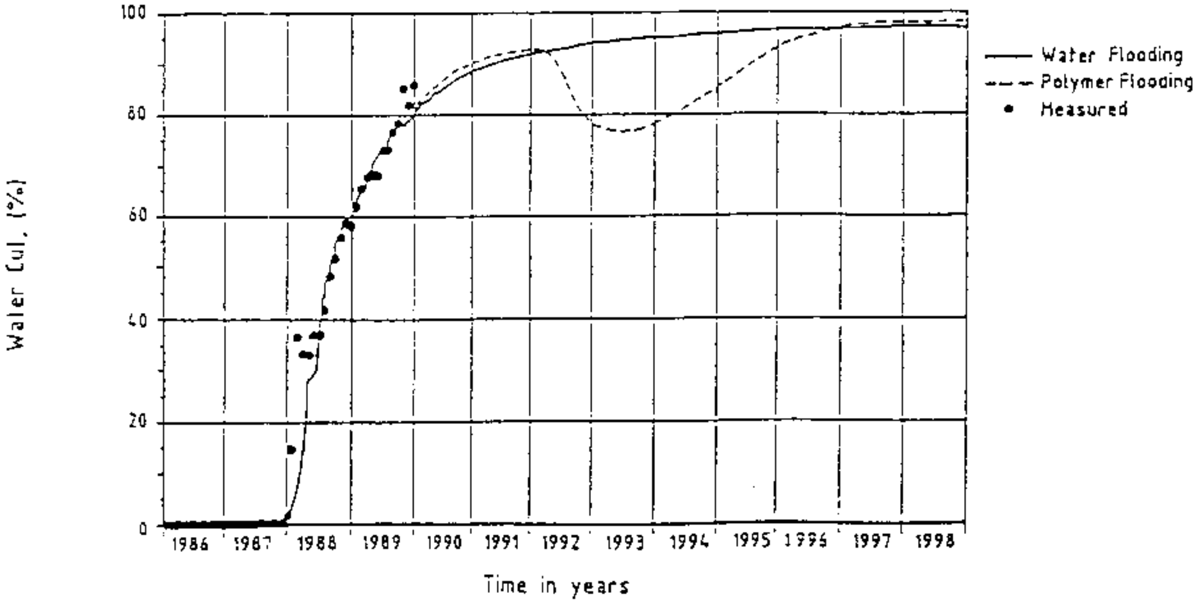


Fig. 15: *Polymer project Vorhop-Knesebeck. Measured and calculated water cut of well 8 for water and polymer flooding*

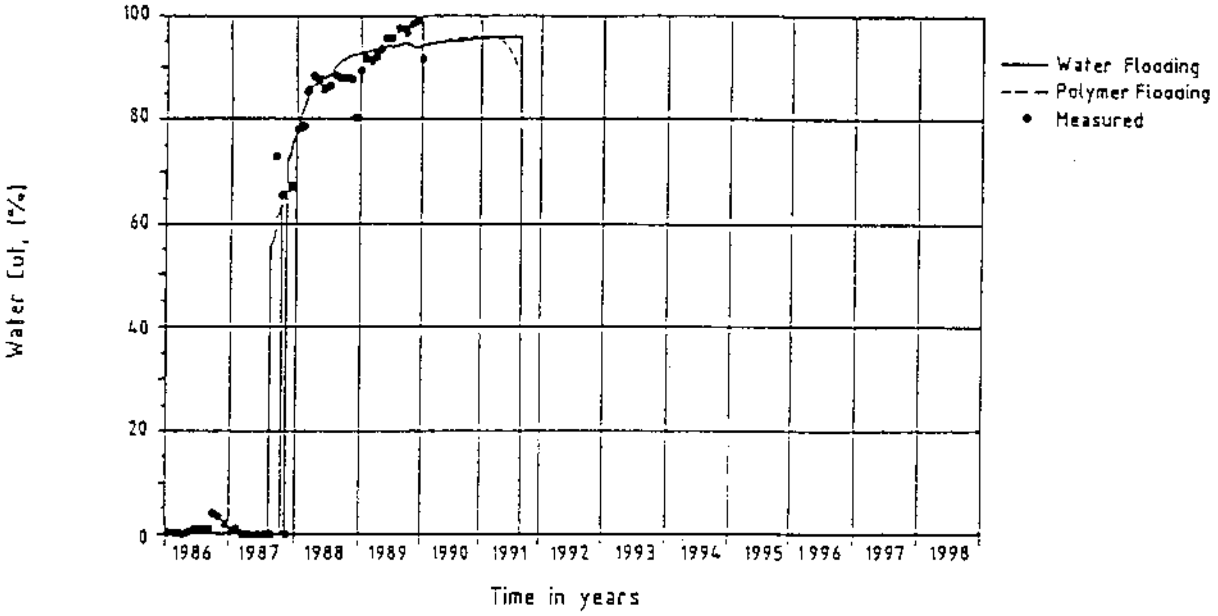


Fig. 16: *Polymer project Vorhop-Knesebeck. Measured and calculated water cut of well 45 for water and polymer flooding*

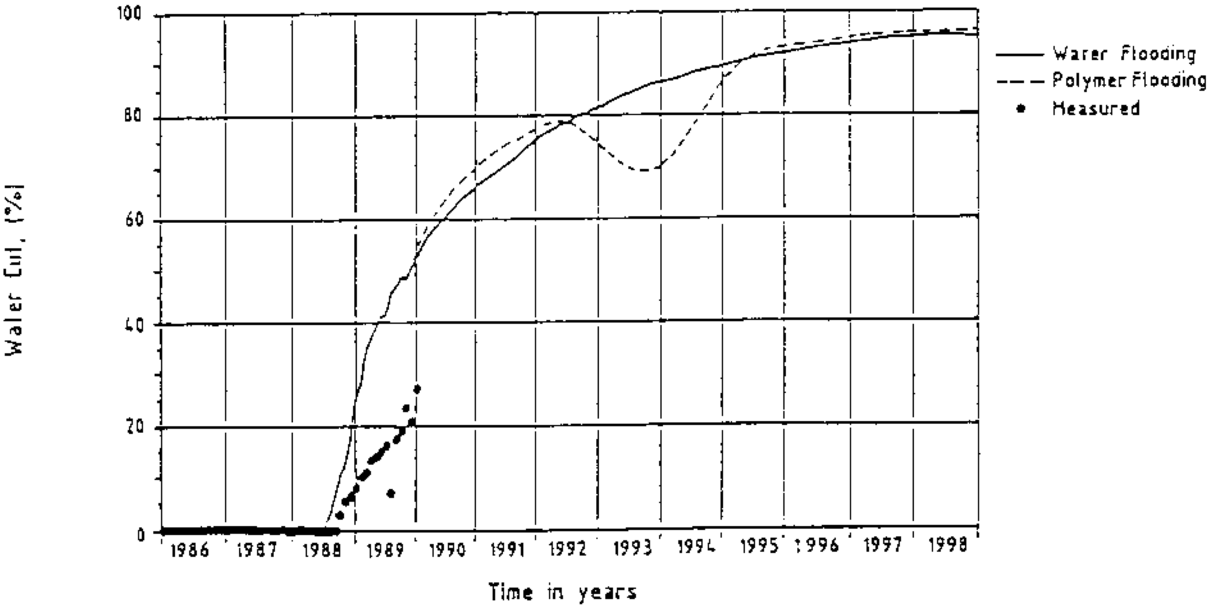


Fig. 17: *Polymer project Vorhop-Knesebeck. Measured and calculated water cut of well 48 for water and polymer flooding*