PREFACE

In the course of 1996 close to 40 fields will be producing on the Norwegian continental shelf. In addition, several new fields are under development. Some of the larger fields are in the mature phase of their lifecycle, and production is on the decline. Improved Oil Recovery (IOR), therefore, is of major importance to oil companies and authorities alike. Maximizing the benefit from natural resources is important, while at the same time IOR represents a tremendous business opportunity.

Research and Development (R&D) represents an important instrument in orchestrating improved recovery from the reservoirs on the continental shelf. The yearly expenditures on petroleum related R&D in Norway is approximately two billion NOK. The oil companies are financing 80%, the authorities and the rest of the industry each support 10% of total costs. Not all of this is targeted at IOR, but IOR related activities represent an important and strategic part of total R&D. The RUTH program has been a significant commitment from both authorities and oil companies in this regard, and the financial support from the oil companies even exceeded ambitious expectations.

RUTH is much more than a collection of R&D projects performed under a common program umbrella. The RUTH program has been executed as a close collaborative effort between the parties involved: The Research Council of Norway, The Norwegian Petroleum Directorate, participating oil companies, and research institutions both in Norway and abroad.

The RUTH program has received considerable recognition both in Norway and internationally. The program has been an inspiration for increased emphasis on IOR, and has contributed to the utilization of new methods for improved recovery on the Norwegian continental shelf. Thus, new methods such as Foam, Gel, and WAG have been introduced. Pilot field tests have been carried out on several Norwegian fields, and results from the RUTH program have also been implemented on fields outside of Norway.

This book represents the completion of the program. It has been written for the purpose of making the result of the program easily accessible for the users. It has been decided to make the book available to the general public, not restricting distribution only to the RUTH participants. We hope it will be useful to a wide audience and therefore, act as a promoter for good reservoir management.

As already mentioned, the RUTH program has been a collaborative effort. The research institutions, subprogram leaders, participating oil companies, authorities, technical advisory committees, technical auditors, and editorial committee are acknowledged. On behalf of the RUTH Board we like to express our appreciation for the rewarding co-operation with all participants and the excellent achievements of the program. Special thanks goes to the program management. The contribution of Leif Hinderaker as Program Manager and Marta Eliassen as Program Secretary was essential for the success of the RUTH program.

Rolf H. Utseth

Statoil

Chairman of the RUTH Board

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THE RUTH PROGRAM

Leif Hinderaker, Norwegian Petroleum Directorate

Introduction

This book presents the main results of the Norwegian R & D program **R**eservoir **U**tilization through advanced **T**echnological **H**elp (**RUTH**). The program lasted 4 years (1992 - 1995). The cooperative IOR effort was conducted by the Research Council of Norway, the Norwegian Petroleum Directorate, Norwegian research organizations and 18 oil companies. The total cost of the program was 106 million NOK. The Research Council of Norway funded 55 million NOK, and 51 million NOK was funded by the participating oil companies.

RUTH was initiated by Norwegian authorities, as a follow-up program after the state funded SPOR research program (1985 - 1991), and was organized by the Research Council of Norway. The research focused on six methods and was organized into six subprograms:

- Gas Flooding
- Combined Gas/Water Injection (WAG)
- Foam
- Polymer Gels
- Surfactants
- Microbial Method

A total of 32 projects were performed under these subprograms. In the subsequent chapters, each of the six subprograms are reviewed, and the main results of the projects are presented in the form of technical papers.

The executing research institutes with the main responsibility were:

- IKU Petroleum Research
- RF - Rogaland Research

The Norwegian Petroleum Directorate (NPD) was in charge of the management and administration of the program.

The oil companies sponsoring and participating in the program were:

- Amerada Hess Norge A/S
- Amoco Norway Oil Company
- BP Norway UA
- Conoco Norway Inc.
- Elf Petroleum Norge a s
- Enterprise Oil Norge Ltd
- Idemitsu Petroleum Norge a.s
- Mobil Exploration Norway lnc.
- Neste Petroleum AS
- Norsk Agip A/S
- Norsk Hydro a.s
- A/S Norske Shell
- Pelican
- Phillips Petroleum Company Norway
- Saga Petroleum a.s.
- Statoil - Den norske stats oljeselskap a.s
- Svenska Petroleum Exploration A/S
- Total Norge A.S

Objectives

RUTH aimed at following up any research from the SPOR program, which were not covered by other programs, and was to include new subjects strategically important for optimal petroleum recovery. The main objectives were stated as:

- Contribute to increase oil recovery from sandstone and chalk reservoirs on the Norwegian Continent shelf by 300 million Sm^3, within technically, environmentally and financially responsible limits.
- Meet the authorities' specific and long-term requirements for research on advanced oil recovery and maintain an independent research competence that the authorities can consult with in connection to their responsibility for the management of the Norwegian continental shelf.
- Help Norwegian research groups to further develop an internationally recognized expertise that can be of use to the oil companies, so that service and systems may be sold for an extra value of

20 MNOK/year in 1996.

Additional objectives were to concentrate on applied research related to advanced recovery methods and to help qualify advanced technology by means of field tests. The methods should have the potential of being implemented in Norwegian fields before the turn of the century.

When these objectives were formulated and the content of the program was defined, the ongoing research in other programs was taken into account. The Joint Chalk Research program had been ongoing since 1982, dedicated to improving hydrocarbon production from Norwegian and Danish chalk fields. PROFIT (1990 - 1994) had been established, also as an follow-up program after SPOR, concentrating on "Reservoir Characterization" and "Near Well Flow". Basic petroleum research on characterization and flow properties of basins and reservoirs was covered by the PROPETRO program from 1991. This was the background for the concentration on applied research on advanced methods in RUTH.

Objectives were defined for the individual subprograms consistent with the main objectives for the program. This is discussed in the subsequent chapters.

Organization

The Research Council of Norway appointed a Program Board with the overall responsibility for the execution of the program. The Program Manager at NPD reported to the Board and was responsible for research contracts, meeting arrangements, and the overall coordination and day by day running of the program.

A workgroup, with representatives from oil companies and NPD, defined at the initial stage important problems and research tasks. The tasks comprised six methods and the program was organized into six subprograms.

Several Norwegian research organizations were invited to bid for the individual subprograms. This process ended up with IKU Research (IKU) and RF - Rogaland Research (RF) as the two main contractors. IKU was responsible for "Gas Flooding" and "Combined Gas/Water Injection". RF was responsible for "Polymer-Gels", "Surfactants" and "Microbial Methods", and IKU and RF in partnership were responsible for "Foam". A subprogram leader either from IKU or RF, was approved for each of the subprograms.

Each of the participating oil companies supported one or more of the six subprograms with an annual fee. The oil company participation was organized through contracts with NPD which was also responsible for the accounting of the funds paid by the companies.

Three technical advisory committees, with members from the participating oil companies and from NPD, followed and guided the projects in cooperation with the Program Manager. Internationally recognized experts from universities in USA and UK acted as Technical Auditors and gave advises based on a yearly appraisal of the technical profile and work performed.

Persons involved in the RUTH organization, as described above, are listed at the end of the book. A list of the oil company participation per subprogram is also included.

Execution

The establishment of the organization described above was essential in the initial phase, and this organization was kept throughout the program period. IKU and RF had the main contracts and several other research organizations were involved as subcontractors. The following Norwegian organizations were in charge of project execution and had project leaders:

- IKU Petroleum Research
- RF - Rogaland Research
- Geomatic
- Norwegian University of Science and Technology - NTNU
- Reservoir Laboratories - ResLab
- SINTEF

International cooperation was a part of the program and was established with research organizations in France, UK, Russia and USA.

The research activities started up for all subprograms in 1992, based on funding from the Research Council of Norway. The oil companies were then invited to participate and thereby extend the scope of work. The total budget for each subprogram was thus determined by the number of oil companies supporting it.

Budgets and activity-plans for individual projects were approved by the Board for each consecutive year of the program. Project leaders reported to the six subprogram leaders, who played an instrumental role in the coordination of plans, activities, reporting and meeting presentations.

The subprogram leaders reported to the program manager and to the technical advisory committees. These committees and their chairmen played a central role in the evaluation of proposed activity plans. They were following the progress of the projects through four committee meetings a year and received quarterly progress reports and yearly or milestone technical reports.

It was decided during the program period that the committee following "Gas Flooding" and "Combined Gas/Water Injection" was too big for detailed technical discussion. Three workgroups were formed under this committee with the purpose of giving sufficient detailed feed-back to the researchers.

Workshops with international participation were arranged for all subprograms. These acted as very valuable fora to exchange results and discuss problems between researchers and experts from the oil companies. Research results were also presented to a wider audience at annual seminars at NPD.

An important aspect of the program was the cooperation on the evaluation of potential and implemented field pilot projects. This activity included three methods: Foam, Gel and WAG. Implemented field tests included Foam and WAG. Pilot Task Force Groups were established for two of the subprograms and represented very constructive fora, where operators presented their pilot plans and could discuss their ideas with researchers and experts from other companies. Furthermore, researchers were, for periods, integrated into the organization of the field operator. In addition to being a benefit for the oil companies, this also added valuable field experience to the researchers' expertise. As a part of this cooperation, the operators were to release more detailed results from the pilots. This implied more openness and availability of the pilot results and helped build an experience base from the pilot-projects.

Results

Important results have been obtained within all six subprograms. These are summarized briefly in the subsequent subprogram reviews. The majority of the projects reached the predefined objectives, but for some of the projects, objectives were adjusted during the project period. The main achievements and results are presented in this book. However, during the program period, about 70 papers have been accepted for presentation at international conferences or for technical journals. This reflects the professional standard of the contributing researchers. Detailed technical reports are also publicly available now, at the end of the program. Reports and papers are listed at the end of the book.

Considering the RUTH objectives, it is relevant to ask if the program has contributed to increase Norwegian oil reserves by 300 million Sm^3. For the 23 oil fields in production or approved for development in December 1991, the average expected recovery factor has increased from 34% to 41% during the program period. This improvement in expected recovery factor adds about 400 million Sm^3 oil to the reserves. In addition, the reserves have also increased because of increased estimated total initial oil in place for the same fields.

This positive development is obviously caused by many different factors. RUTH has, without doubt, contributed actively to initiate and evaluate pilots in order to qualify new and advanced methods. During the program period, pilot activity on WAG, Foam and Gel were established on the Norwegian continental shelf and further pilots and field applications are planned. The possibilities to use gas for IOR-purposes, as gas flooding or combined with water injection, are now being evaluated for many Norwegian fields and firm plans exist for some fields. Future Norwegian reserve additions due to gas injection could therefore be significant.

Use of Surfactants was from the start of RUTH a theme with a high risk, but also with a high technical potential. Even though excellent research was performed, surfactant flooding remains uneconomical at current oil prices. Compared to the other methods evaluated, Microbial Methods is technically more immature. Offshore fields trials was not considered during the program period, but the method has a potential of being a cost effective IOR method in the future.

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THE COMBINED GAS-WATER INJECTION SUBPROGRAM

Idar Akervoll, IKU Petroleum Research

Introduction

Combined-Gas-Water (CGW) injection strategies in this context comprise Water-Alternate-Gas (WAG) injection, gas injection following water injection in fractured chalk and sandstone reservoirs, and simultaneous or combined injection for pressure maintenance or gas storage purposes. The subprogram also addressed recovery of attic and cellar oil by CGW injection strategies.

Injection of seawater has been a part of the development strategy for most of the North Sea oil reservoirs. The volume of oil left behind after water flooding comprises both bypassed oil in unswept reservoir zones and capillary trapped oil in swept zones. The bypassed oil is associated with poor sweep efficiency, whereas the capillary trapped oil is associated with poor microscopic displacement efficiency. Parts of this remaining oil represent a target for WAG injection.

Poor sweep efficiency is, in particular, associated with gas flooding due to early breakthrough of injected gas as a result of rapid gas segregation to the top of the reservoir, or the fact that gas may shoot through high permeable layers in the reservoir, and high gas mobility. A CGW injection scheme may be designed to improve the gas sweep efficiency and thereby improve the recovery of oil from the field.

WAG and CGW injection schemes have received interest in recent years as methods to accelerate and improve oil recovery (IOR) in the Norwegian sector. This subprogram has been involved in two field WAG injection pilots that are being executed in sandstone reservoirs on the Norwegian shelf.

This review presents subprogram main goals, subprogram make-up, main project results, WAG pilots, and future outlook.

Main Goals

The subprogram main goals were:

1. Develop technology within CGW injection to secure long-term optimal utilization of petroleum resources. More specific:
    a. Development of laboratory and numerical tools to forecast improved oil recovery from sandstone and fractured chalk reservoirs and contribute to establish a technical foundation required to plan a gas/water injection pilot in a Norwegian field contingent upon cooperation with a selected license group.
    b. Scaling of static and dynamic reservoir parameters from laboratory to field dimensions - reservoir parameters related to Combined Gas-Water injection in both sandstone formations and fractured chalk reservoirs.
2. Develop marketable services and tools to assist the oil industry improve oil recovery by CGW injection in fractured chalk and sandstone fields.
3. Acquire marketable services and research work within the subject area in 1996 quantified to be above the sales in 1991. One third of the incremental sales should be export.

Projects

The philosophy behind the design of this subprogram can be illustrated by Stone's analytical model for segregation of gas and water during injection of the two fluids in a simplified (homogeneous and horizontal) slab reservoir model.[1] He introduced a model with a zone of mixed flow of gas and water, segregated gas swept and water swept zones and a dimensionless group related to WAG processes, the viscous/gravity ratio, VGR defined as:

$$VGR = \frac{q_t}{\Delta p \cdot k_v \cdot g \cdot a\left(k_{rw}/\mu_w + k_{rg}/\mu_g\right)}$$

where

q_t =volumetric flow rate

Δp = density difference

k_v =vertical permeability

g = gravitational acceleration

a = horizontal area flooded by one injection well

k_r = relative permeability

μ = viscosity

subscripts: w = water, g = gas.

It can derived from this that an increment of VGR will increase the size of the mixed flow zone, and thereby increase the sweep and recovery efficiency of the WAG injection process. In a real reservoir, heterogeneities will be important for the total sweep efficiency obtained by CGW injection.

The topics of the subprogram are the following:

The Efficiency of CGW Injection Processes

This project relates field scale reservoir parameters to the efficiency of CGW injection processes. These parameters are volumetric injection rate, which are linked to operational constraints offshore, reservoir geometry, heterogeneities and well spacing, and reflects q_t a and k_v in the VGR group above.

The project contributes to reach the goals 1b and 3 and deals with simulation of CGW injection in parts of a fluvially deposited reservoir with heterogeneities and geometry within a single conducting channel. Heterogeneities in terms of variable permeability were generated by stochastic simulation. These permeabilities were, furthermore, modified to study the effect of different heterogeneity profiles in terms of average permeability versus depth, and of heterogeneity contrasts in terms of the spread of permeability around this average value.[2]

The work showed that heterogeneity contrasts extend the gas-water mixed flow zone and improve the WAG efficiency.

Gas Mobility during Three-Phase Flow in CGW Injection Processes

This project is a study of the effect of three-phase relative permeabilities (gas, water and oil) on the efficiency of CGW injection processes. Determination and modeling of the influence of saturation history, fluid interfacial tension and spreading power is included. The content of this project includes

$(k_{rw}/\mu_w + k_{rg}/\mu_g)$ in the above VGR group and contributes to goal 1 a and 2.

The results were obtained mainly by capillary pressure and relative permeability measurements. Key factors are wettability and hysteresis (saturation history).[3]

WAG Injection in Composite Layered Core and Diffusion in Fractured Structures

This project includes the effect of communicating sandstone layers on WAG injection processes, and diffusion contribution to the total transport in reservoir structures. It contributes to goals la and 2. The project comprises design and construction of a composite layered flow model with permeability contrast; miscible gas floods by use of model fluids; miscible WAG injection subsequent to waterflooding at reservoir conditions in a layered long core; immiscible gas injection under CT surveillance; design, simulation, and physical performance of an immiscible WAG experiment under CT surveillance.

Multicontact miscible WAG injection in the layered long core at reservoir conditions by use of North Sea reservoir oil and separator gas, raised the recovery factor by 36% of STOIP beyond that of water flooding. The experiments were simulated using a compositional reservoir simulator that included molecular diffusion.[4]

It was found that three dimensionless parameters determine the importance of diffusion for miscible displacement in a fractured reservoir; a velocity parameter, a field scale diffusion parameter, and a dimensionless distance.

Physical Gas/Water Segregation Model

The project includes construction of a 2D physical flow model, experiments on gravity segregation of gas and water in CGW and WAG injection, and incorporates p, k_v, and other most relevant variables in the VGR group above. The model is filled with glass beads. Two sets of injection fluids have been used; gas/water and a model system having low interfacial tension (IFT) in order to scale the experiments. Based on relative permeability data measured for both fluid systems in a one dimensional pack of the same glass beads, flow zones for mixed and segregated flow were predicted by the Stone-Jenkins segregation model, and by numerical simulations. For the low IFT model system, the measured and predicted flow zones are in good agreement, both for coinjection and alternating injection.

Relative permeability data measured in standard one dimensional core flooding experiments, involving cocurrent flow of the phases, are also representative for describing gravity segregation of gas and water phases, which is a process that has elements of countercurrent flow.

Field WAG pilots on Snorre and Brage

This topic includes WAG injection pilots underway at two producing North Sea oil fields.

The Snorre WAG Pilot was initiated by Saga Petroleum a.s at the Snorre Field early in 1994. The reservoir is a fluvial deposition and contains strongly under-saturated oil.[5] A miscible WAG process is expected with extensive exchange of components between the injected gas and the reservoir oil.

The Brage WAG Pilot was initiated by Norsk Hydro, late 1994, at the Brage Field in a Jurassic sandstone accumulation. Stochastic reservoir modelling tools were used to obtain a second opinion to the deterministic geological model of reservoir in the WAG pilot area. An immiscible WAG process is expected from the separator gas injection.

Tertiary Gas Injection Following Imbibition in a Long-Core Chalk Sample

This project is a study to measure the recovery efficiency of gas injection after spontaneous water imbibition in chalk core samples. Gas was injected at pressures substantially above the bubblepoint pressure of the reservoir oil. The pressure was increased by water injection. The topic includes simulation of the laboratory experiments.

Lean gas injection after spontaneous water imbibition and increase of pressure in a stack of chalk cores (outcrop and Ekofisk cores) has been investigated. The measurements concentrated on the effect of gravity drainage, diffusion with swelling of fluids in the core, saturation redistribution, lowered gas-oil interfacial tension (IFT), reduced oil- gas density difference, and conditions for capillary contact in a stack of chalk samples.[6]

No or little free oil was produced into the surrounding of the stack of cores, mainly water was produced, when gas was injected after spontaneous water imbibition. Lean gas injection and pressure increase at intermediate water saturations result in the same conclusions. Spontaneous water imbibition with initial gas in the cores, resulted in the same residual oil saturation as without residual gas. Spontaneous water imbibition and vaporization were the main production mechanisms.

Dual-Porosity, Dual-Permeability Formulation for Fractured Reservoir Simulation

The project comprise a review of key mechanisms in fractured reservoir flow modeling, mathematical formulation of flow in fractured reservoirs, and application of models on fractured systems.

A new concept, referred to as the multiple grid concept, has been developed. The method is based on finer gridding of the matrix blocks where the local flow phenomena are calculated by two scales of calculations.

Evaluation of Tertiary Flooding of Fractured Chalk Fields using Numerical Simulation Models

This project is a study of the potential for further improvement of oil recovery in a generic model representing a typical naturally fractured chalk reservoir in the Ekofisk area. A generic dualporosity model was constructed for this purpose.

Tertiary flooding of chalk fields requires a significant back-production period of injected fluid. An aggressive well drilling and stimulation program is required to accelerate the production.

WAG Workshops

Three international WAG workshops have been arranged, each with 30-40 participants. Speakers from the participating oil companies have shared their field experience on WAG operations, research and planning of WAG pilots, and results from the subprogram have been discussed.

Results

The main results of the subprogram are:

1. The efficiency of a CGW injection process is related to reservoir heterogeneities and to the size of the mixed gas-water flow zone in the reservoir. Within a conducting fluvial flow channel in a sandstone reservoir, the mixed flow zone was larger than what was derived from Stone's segregation model due to capillary effects and due to heterogeneity contrast.
2. It has been demonstrated in laboratory experiments, that it is necessary to evaluate the saturation histories that will take place during CGW injection processes. The formulations used in modeling these processes must reflect the physics of the process in question and be tuned to properly scaled experimental data.
3. The Snorre WAG injection pilot responded with an immediate acceleration in oil production. Early gas breakthrough was experienced in one production well high up on the structure, but major gas breakthrough has not been observed in other producers.
4. The Brage WAG Pilot fluid saturations and distribution in the WAG pilot area in the reservoir are in the oil-water capillary transition zone. Three mobile phases are expected to be present in pilot area. Segregation of gas and water dominate the immiscible WAG process. About 5% improvement in oil recovery is estimated by WAG injection compared to water injection.
5. Physical experiments and analyses of CGW injection around a stack of fractured chalk cores showed that spontaneous water imbibition and vaporization of intermediates were the main production mechanisms during recovery of oil from the cores.
6. Numerical simulations using dual porosity, dual permeability models showed that recovery of oil is improved if capillary continuity exists between the matrix blocks. The simulations indicate that reinfiltration of oil (block-to-block process) may play an important role.
7. It is indicated by simulation on a generic fractured chalk field model that oil recovery, technically speaking, may be enhanced by tertiary injection. The tertiary flooding efficiency strongly depends on the applied three-phase oil relative permeability correlation.

Future Outlook

The future outlook is promising for WAG and CGW injection methods to improve oil recovery from fields on the Norwegian shelf. The ongoing field WAG pilots have demonstrated that WAG injection in the pilot areas are both technically and economically successful. The pilots have qualified the WAG injection scheme for extended field scale application.

The estimated IOR potential is about 150 million Sm^3 oil by WAG and CGW injection in the Norwegian sector from fields in production and fields to be developed.

In a collaborative study between NPD and operators in the sector, 15 reservoir units are considered to have favorable properties for WAG and CGW injection. The incremental recovery is 3% to 7% of STOIP on average from individual fields.

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THE GAS FLOODING SUBPROGRAM

Odd Steve Hustad, IKU Petroleum Research

Introduction

Gas injection has successfully been implemented in Norwegian reservoirs having high permeable, dipping, sandstone formations.[1] Gas flooding in such reservoirs result in high recovery factors and in many instances the technology is proven. However, it remains a challenge to prove its economical benefit for low permeability sandstone and chalk reservoirs in times of low oil prices.

Typical for gas flooding is that its microscopic sweep leads to lower residual oil saturation as compared to water flooding.[2] The low oil saturations are mainly due to the interplay between capillary and gravity forces, and phase behavior.

Although residual oil saturation is low in regions swept by gas, the sweep efficiency is often of concern in highly heterogeneous and faulted reservoirs. This implies that certain reservoir factors, like reservoir geometry, rock structure and rock characteristics are important when deciding upon gas injection processes.

Processes where gas drains the oil are preferred, compared to viscous dominated processes due to the gas' mobility and gravity ratios to liquids. Gas in low permeable rock requires more time to sufficiently drain oil, compared to good quality rock. Gas migration into other poorer quality reservoir regions also has a time factor associated to it. This time factor may be crucial for certain reservoirs when trying to meet the required economical constraints. The migration times of gas into various rock qualities will therefore have an impact on the oil recovery factor that is achievable. The hydrocarbon volumes, phase behavior and rock quality distributions will therefore be important parameters for gas flooding predictions.

Goals

The objective of the subprogram was to improve today's technology by reducing the uncertainties of oil recovery predictions. By identifying critical parameters and phenomena for gas flooding, technological improvements may be made. The gas flooding subprogram had therefore the following three goals to support the RUTH program's general goals.

1. The gas flooding subprogram aims to continue the SPOR program activities by improving the understanding of the mechanisms that lead to reduced oil saturation in the reservoir during gas flooding processes and thereby increasing the oil recovery. The use and development of simulation tools and physical measurements should lead to better field predictions and improved oil recovery.
2. The gas flooding subprogram aims to identify major field related criteria that will lead to significant increase in oil recovery, identify the energy input, and the emissions of gases hazardous to the environment.
3. Through improved analysis techniques (laboratory and numerical) and publication of results, obtain increased future interest for research and technological consultant services.

Projects

Four projects have been executed within the Gas Flooding subprogram.

Energy and Environmental Aspects Related to Gas Flooding Processes

The objective was to evaluate the energy requirements and the net energy gain from gas injection processes, the discharge of pollutants to the environment, and apply these factors to specific Norwegian reservoirs.

A model for estimating the energy requirements for gas flooding in water flooded reservoirs using hydrocarbon gas, nitrogen and carbon dioxide (CO_2) as injection gases has been developed.

Energy scenarios for specific fields show less energy requirement compared to the average requirement for water injection. Tertiary gas injection will give a large positive energy balance. For hydrocarbon gas injection, this balance is dependent on the recovery factor of the injected gas.

On the basis of these various energy scenarios, the environmental load due to emissions of gases into the atmosphere proved insignificant, with the exception of nitrogen, compared to the total Norwegian emissions of the same gases. Massive nitrogen injection can, however, double the Norwegian emissions.

Injection of CO_2 can potentially give large net reduction of CO_2 (169 million ton/year) if the CO_2 comes from industrial sources (coal power).

The Scaling of Petrophysical Parameters during Gas Flooding Processes

A general method for scaling three dimensional three-phase compositional simulation based on a fine scale simulation scenario has been developed within this project. The developed algorithm matches on coarse scale grid block compositions using a least square error method. Simulated scenarios show that the scaled relative permeabilities (pseudo-functions) are dependent on many factors. Factors like gravity and capillary forces, phase behavior, dimension, position and grid block sizes (numerical dispersion) all have a significant impact on the resulting pseudo functions obtained by the developed scaling procedure.

This methodology provides improved capabilities in establishing effective reservoir parameters for field scale simulation, thereby fulfilling the first goal. However, the future interest to apply this method will judge if the third goal will be fulfilled.

Fluid Flow in Fractured Chalk Reservoirs

This project dealt with chalk reservoirs and was divided into three parts. Part A was a laboratory study with the objective to measure the recovery efficiency of gas-oil capillary/gravity drainage in a long-core chalk sample at reservoir conditions when gas injection substantially increases the reservoir pressure. In Part B, the aim was to evaluate the effect of gas flooding in fractured reservoirs through a series of detail simulations using a dual porosity reservoir simulator. In Part C, an evaluation of Part A's gas flooding experiments was performed by simulation.

Results from the laboratory core flooding experiments show that lean gas injection provides significant oil recovery potential in fractured chalk reservoirs. The matrix block height, the developed interfacial tensions and fracture gas composition are the main controlling parameters for oil recovery. The production mechanisms are a combination of gravity/capillary drainage and redistribution, together with vaporization of the oil.

Practical simulations of the experiments, although difficult to perform, show that the experiments were mainly dominated by phase behavior effects, like diffusion, swelling and vaporization.

The dual porosity simulations of miscible and immiscible gas injection in fractured chalk reservoirs have shown that improved oil recovery can be obtained beyond that of water flooding by; pure gas injection, tertiary water injection after gas injection, and tertiary gas injection after water flooding.

The simulation with the constructed dual porosity generic model, typical for North Sea fractured chalk fields, showed that fluid and rock characteristics are important to evaluate. The results were sensitive to the choice of three-phase oil relative permeability model used in the simulations.

Mechanisms Affecting Residual Oil Saturations

This project also had three parts. Part A's objective was to describe experimentally how different wetting and spreading characteristics influence the oil recovery by gravity drainage during gas injection in highly permeable sandstones. In Part B, the aim was to investigate how relative permeability and capillary pressure can be applied in simulations to model vertical tertiary gas flooding experiments. In Part C, the objective was to apply the knowledge obtained from Parts A and B to gas injection simulations for a particular field.

This project has contributed to the subprogram's goals. The six core flooding experiments performed show that residual oil saturation is very low, irrespective of the wetting nature of the rock for spreading oils. The drainage rates of these oils are dependent, however, on the rock's wetting characteristic.

A new three-phase formulation for relative permeability and capillary pressure was developed to improve the modeling capability of gravity drainage experiments. The formulation has also been implemented in a commercial simulator, Eclipse 300.[3]

The commercial simulator has been applied to simulate gas flooding processes of an actual field using the new three-phase formulation. The results show that the various wetting characteristics have an impact on the relative permeability to water (gas-water system) and thereby influencing the drainage efficiency of oil.

Results

The main subprogram achievements are:

1. Gas injection will give a positive energy balance. The environmental impact due to emission of gases to the atmosphere proved insignificant, with the exception of nitrogen, compared to the total Norwegian emissions.
2. A general method for upscaling of three dimensional three-phase compositional simulation has been developed for the determination of effective petrophysical parameters.
3. Phase behavior through vaporization and redistribution of phases are major mechanisms during gravity/capillary drainage of oil by gas in fractured chalk reservoirs.
4. Simulations with a dual porosity simulator show that gas injection in fractured chalk reservoirs improves oil recovery.
5. Residual oil saturation is very low for spreading oils in highly permeable sandstones irrespective of the wetting characteristics.
6. A three-phase formulation for relative permeability and capillary pressure was developed for improved modeling capability of gravity drainage gas injection processes.

Future Outlook

Gas flooding has proven its ability to be a successful process to increase oil recovery. The implementation of the process is still hampered by various issues related to reservoir uncertainty and economical constraints.

Since gas injection will give increased oil recovery, it is important to understand the extent to which this increase in recovery will compensate for the economical loss from not selling the gas. The result from such analysis will be case dependent and dependent on future gas prices.

The problem of scales will still remain as a technological challenge for reservoir engineers. Predictive field scale simulation of gas injection is strongly related to the problem of reservoir description. The challenge also lies within the prediction of fluid distributions and fluid flow through complex reservoir geometry. The ability to predict gas saturation distribution in heterogeneous reservoirs still remain unresolved and should be further pursued.

At the end of any hydrocarbon gas injection project, the reservoir can still produce more oil. The injected gas that remains in the reservoir may be produced by either water injection or depressurization, bringing with it condensate attained from the residual oil.

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THE FOAM SUBPROGRAM

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Introduction

The high mobility of gas in a reservoir can result in poor sweep efficiency, production at high gas/oil ratio (GOR), and reduced oil recovery. Injected gas may give poor areas sweep due to fingering and poor vertical sweep by gravity override or flow in high-permeable streaks. Viewed from a production well, high GOR production can be caused by gas coning, cusping, or channelling.

Foam can be used to control the flow behavior of gas by retarding and diverting it, and can be applied in injectors or producers. Inside rock pores, foam consists of liquid films that make the gas phase discontinuous. The unique structure enables foam to selectively reduce gas mobility by orders of magnitude. Worldwide, foam is a proven technology for steam injection; with other gases it remains at the development stage.

Objectives

The main objective was initially stated as "To lay a sound foundation for doing a foam pilot in a Norwegian field", with associated subgoals being to:

- Identify the field and process to be used
- Define how to select a suitable product
- Predict foam behavior in the field

The producer treatment with foam done by Norsk Hydro in 1994 at Oseberg B-27, and the active support this pilot received from the subprogram on all three sub-goals defined in fact caused the main goal to be reached a year ahead of plan.

For its last year, the Foam subprogram was therefore reorganized (see later) with the objective of extending the original target to several pilots by designing efficient foam processes for other field applications.

Scope

The Foam subprogram has addressed most key aspects of foam application to North Sea reservoirs, ranging from studies of film stability and pore-level flow mechanisms to evaluating the field application potential and directly supporting pilot-test efforts of the sponsor operating companies. Based on the defined sub-goals, efforts were centered on three key challenges, expressed in the form of well justified questions posed by an operating company to a specialist R&D team:

- How can my field benefit from the use of foam?
- How do I select a suitable foamer?
- How do I predict the results?

Question 1 has been addressed by cataloging the existing field experience with foam, categorizing the production problems of greatest interest for North Sea application, and defining critical application parameters for each production problem and foam process type. Production well treatments were found to have the major North Sea potential at least in the short term and, hence, have been the main focus of work.

Question 2 was addressed by defining guidelines for product screening and qualification work, designing relevant experiments and test protocols and obtaining specific results for selected foaming agents of interest, at conditions relevant for the pilot tests studied.

Question 3 was addressed using two parallel approaches: validating the best available (foam-capable and field-tested) reservoir simulator option on selected lab data, and simultaneously running several suites of generic and specific simulations.

Selected more basic scientific issues at the root of all three questions formulated were addressed by integrated work on foam and thin-film properties, pore level foam/oil interaction, and mathematical modelling. Retaining the program's applied focus, these studies have been done in collaboration with leading academic groups and researchers worldwide, but form an integral part of the program.

Projects

A project *Foam process and product development* was defined in response to Question 1. The work included reviews of field experience, process simulations on a generic reservoir, and experimental studies of GOR control aimed at optimizing the gas-blockage performance of hydrocarbon foams and enhancing that of aqueous foams.

The project *Foam screening parameters* was designed to answer the challenge of Question 2 as an attempt to define a test protocol for product selection through systematic variation of the experimental parameters. A broad selection of foam experiments was completed at a wide range of conditions ranging from an Oseberg long core at reservoir conditions to a pore micromodel. The most important finding was that general foamer screening procedures cannot be defined, because foam performance is highly dependent on the mode of experiment.

The third major project, *Foam simulation tools*, was defined to answer Question 3. By simulating selected experiments, the power as well as limitations of the STARS simulator were identified. Further projects were *Foam in fractured reservoirs*, a scoping study, and *Segregation in foams*, a physical model study conducted together with the Combined Gas/Water subprogram.

Following completion of the Oseberg and Beryl pilots in 1994, the subprogram activities were re-organized in two projects to better transfer this experience to the other three field trials planned. The project *Foam application support* included a range of simulation studies related to the new planned pilots, continuing product development, and the foam workshop. A new project, *Foam process design*, was assembled to wrap up the activities relating to product selection and simulation of experiments.

From Lab to Field

Specific technical support was contributed to the following completed and planned field pilots:

- Oseberg (Hydro, 1994): Prepilot evaluation of foam potential, foam properties in long reservoir cores, pilot interpretation and postpilot history matching and foam process simulation.
- Beryl (Mobil, 1994): Advice on pilot design and interpretation.
- Rabi (Shell, planned): Optimization of hydrocarbon foamer system, vertical-well pilot plans.
- Statfjord (Statoil, planned): Prepilot evaluation of foam potential.
- Snorre (Saga, planned): Prepilot injector-treatment potential; product evaluation.

Results

This section highlights major achievements of the Foam subprogram relative to the technical status prior to RUTH [1]. Five companion papers [2-6] summarize specific results, which are documented also by 16 international conference papers (excluding RUTH seminars) and 18 RUTH Technical Reports. The 1st and 2nd International Workshop on Reservoir Applications of Foam (at Stavanger 1993 and Røros 1995, respectively) gathered technical specialists from several countries and summarized key results in the context of this field of research.

- Foam IOR technology has been advanced to a stage where the value of foam to limit gas influx into production wells has been demonstrated. First-order treatment design criteria are now available for North Sea application. The key to these major steps forward has been a deep integration of targeted R&D, field data analysis, and an exceptionally open dialog with the operating companies. Organizing this dialog through the Task Force on Foam Pilot Testing proved highly valuable for achieving positive feedback between field tests and R&D activities.

- The experience gained means that new pilot tests and commercial projects with foam now can be approached with much greater confidence and this improved basis for the field-specific foam process tuning has reduced the planning time.
- Extensive laboratory work on a wide range of foam systems and conditions has shown decisively that no product selection method exists that is suitable for all foam processes. The experimental mode and test procedures must be carefully defined in advance, because foam properties are process-dependent as well as reservoir-specific. In particular, injector and producer treatments may require quite different foam systems.
- For GOR control, foam systems have been identified and, partly, qualified to give efficient gas blockage at a wide range of North Sea field conditions. A significant part of these results is applicable also to injectant diversion treatments.
- In-depth mobility control remains a more distant goal than GOR control or diversion. However, segregation experiments indicate that segregation in foam occurs more slowly than expected from theory for gas and water, which should improve the chances of foam assisting vertical sweep.
- Much improved foam performance by adding polymer or gelant and by blending low-cost and high-performance foamers has been demonstrated at reservoir conditions.
- The simulator STARS is a powerful and flexible tool for designing and interpreting field and lab data involving foam. However, efficient use of STARS requires a thorough knowledge of foam processes, critical parameters, and lab input data in order to obtain meaningful results.
- Other proposed foam simulation methods have been evaluated and compared with the STARS empirical model. These were found either to be limited to first-order potential studies of a kind that could also be accomplished without any foam functionalities, or to lack key features needed for reservoir simulation.
- The first comprehensive study of foam in realistic size pore micromodels done has revealed that a lot still remains to be learned about pore-level foam process mechanisms. The flowing steady state and resistance of bubble trains seems to be of less importance than previously thought, while flow and rearrangement of liquid, phase trapping, stagnant lamellae, and coupling of capillary phenomena over several pores is more important. Oil/foam interaction is also more complex on the pore level than assumed from prior work.

Outlook

Despite the advances made, critical aspects of foam application in the reservoir are not so well described that foam technology can leave the developmental stage and enter the engineer's general tool kit. Of primary concern, efficient control over placement of foam in the near-well region is lacking and foam simulation techniques are still rough and include uncertain physical assumptions. Both these shortcomings are rooted in our still weak understanding of the basic pore-level mechanisms of foam in porous media.

A better description of these phenomena is needed if foam simulation is to advance beyond its empirical (interpolation) stage and thus allow efficient treatment design for new field-scale applications. The simulator does represent, in a rudimentary way, most aspects of foam physics and could be improved by modifications. However, for STARS to become a truly predictive tool requires a deeper process understanding mechanisms, sensitivities, and upscaling than we have today.

Better process understanding is also critical for oil/foam interaction and stabilization mechanisms in enhanced foams. Combining experiments in realistic-sized pore micromodels with high quality core experiments is believed to be the best tool for improved description of foam treatments.

On a field scale, the most critical remaining challenges are to better characterize the flow conditions in the region of the reservoir affected by high gas mobility, and to use this knowledge for a more accurate definition of the problems to be treated by foam.

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THE POLYMER GEL SUBPROGRAM

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Introduction

Water production problems have a range of origins, and a large number of options and processes exist to reduce water-cut.

Gel technology has been used to cure water production problems caused by leakage in or behind the casing; fractures; coning or heterogeneous reservoirs. Gel technology has also been successfully used in the Prudhoe Bay field Alaska, for gas shut off.[1] The gel technology is characterized with use of rather small quantities of chemicals.

There is an industry demand to extend gel technology to treatment of high temperature reservoirs and in-depth treatment. This require gel systems with delayed gelation rate and with low retention. Retention can have a large impact on gel placement and performance.

Gel treatment failures are often caused by improper placement due to communication between layers with crossflow, or by communication in the well completion. The success ratio can be improved by applying improved placement techniques.

World-wide the different gel projects have involved over 3500 wells (including offset wells).[2] In the North Sea sector far fewer, below 20, treatments have been performed.

Objectives

The two main objectives of the polymer-gel subprogram have been to:

- Identify and characterize stable gel systems with adjustable gelation time. The gel systems should fulfill the criteria set for:
  - Deep injector treatments
  - High temperature producer treatment
- Prepare for a field application (pilot test).

Projects

The work has been divided into the eight projects listed below.

Polymer gels for Deep Emplacement - Metal Complex Crosslinking

Goal: Identify and characterize stable gel systems with adjustable gelation time by using metal complex crosslinkers.

Protecting ligands on the crosslinker have been used to obtain a delayed gelation rate, and a large number of gel systems have been evaluated. Metal complex crosslinkers (metal complex ligand system based on chromium, aluminium, titanium and zirconium) were examined and hydrolysed polyacrylamides, co- and terpolymers were the main polymers used.

Temperature stable gels with flexibility in terms of gelation time have been identified and characterized both in bulk and in porous media.

Polymer gels for Deep Emplacement - Covalent Crosslinking

Goal: Identify and characterize stable gel systems with adjustable gelation time by using covalent crosslinkers.

Two principles of delayed gelation of covalent systems have been used: (I) Protection of reactive groups on the crosslinker, and (2) Delayed action catalysts, where a compound (acid) that will promote the reaction between polymer and crosslinker is liberated at a controlled rate. The most promising results have been obtained with method 1.

Alternative crosslinkers to glutaraldehyde were evaluated for delay of gel formation in the polyvinyl alcohol (PVA)/dialdehyde system. It was found that the crosslinker 2,5-dimethoxy-2,5 dihydrofuran delayed gel formation significantly and improved stability of the system.

Thermal Stability of Thin Gels

Goal: Determine the stability of thin gels at anaerobic conditions.

Several gel systems have been tested for thermal stability up to 120°C under anaerobic conditions, both with bulk, sand pack and reservoir coreflood experiments. Some low concentration gel systems have shown to maintain a high residual resistance factor over a long period at 120°C and anaerobic conditions in porous media.

Gelant Transport and Placement in Heterogeneous Systems

Goals: Evaluate critical parameters for gel treatment of sandstone and chalk reservoirs. Study the dynamics of gelant flow in layered system with crossbow. Improve placement techniques.

In sandstone reservoirs, gel treatment is found to be most efficient in systems with high mobility ratios and when the displacement mechanism is dominated by viscous forces. Best results were obtained with the high permeable layers in the upper/middle part of the reservoirs and with some restrictions to vertical communication between the layers.

In fractured chalk reservoirs, gel is found to be most efficient when fracture/matrix permeability contrasts are high and when viscous forces significantly contribute to the displacement mechanism. Near well treatment may be detrimental for the injectivity/ productivity and overall reduction of fracture permeability is detrimental.

Correct placement is crucial for success for a treatment, and a new placement technique was proposed and demonstrated in 2D experiments.

Environmental Evaluation of Chemicals for IOR

Goal: Increase the knowledge of the environmental harmful effects and the quantities of IOR-chemicals that may be discharged into the sea.

An environmental evaluation of IOR chemicals has been performed. This evaluation includes a literature survey and an experimental screening using Microtox® system. Chromium acetate and chromium malonate were also tested on Skeletonema costatum and Acartia tonsa.

Gel treatment - Gyda pilot

Goal: Evaluate potential for the use of gel on the Gyda field.

In this project an evaluation of a gel pilot candidate on the Gyda field has been performed. The Gyda reservoir is deep and hot (154°C). The water injection wells operate in low permeability rock, (average permeability is approximately 30 mD) and performance depends strongly on achieving unusually long thermal fractures. Due to the high temperature only injector treatment was considered.

Simulations have shown that gel treatment can change the shape and size of the fracture and consequently the effect of a gel treatment is closely linked to the thermal induced fracture performance.

Core flooding experiments using Gyda reservoir cores have identified possible gel systems for injector treatment.

Gel Pilot Prospect in the Snorre Field

Goal: Evaluate the potential use of gel for a producer on the central fault block in the Snorre field.

Due to the heterogeneous layered reservoir with large permeability contrasts water breakthrough in the high permeable layers.

Placement of gel were investigated using a radial simulation model (UTCHEM). Three different chemical gel systems were studied and all systems predicted appropriate gelation times. The effect of treatment on field scale was studied using the ECLIPSE model for the central fault block on Snorre.

A PLT log run in November 1995 showed that the watercut for well is still only approximately 5% - 7%. No treatment will be performed before a higher watercut is observed.

Gullfaks Pilot Study

Goal: Evaluate the potential use of gel for a horizontal injector and a horizontal producer in a segment of the Gullfaks field.

An evaluation of the gel treatment potential was performed for a segment in Lower Brent (Etive/ Rannoch) in Gullfaks for a horizontal producer and a horizontal injector. Water override through the high permeable Etive formation is a well-known problem for the Gullfaks field.

Almost no potential was found for producer gel treatment due to too high degree of communication along the horizontal producer. The horizontal injector is perforated in Rannoch. However, considerably water is injected into Etive due to fractures. Preliminary results show that reduction of this Etive injection by use of gels has a large potential for sweep improvement but some depressurisation of the segment is needed.

Field Application

No pilot has been performed within the RUTH program period. On the Snorre field, the average field watercut is currently at a moderate level of about 15%. Five wells have watercuts between 10% and 50%. A gel pilot in 1996 seems appropriate according to expected field performance.[3]

Statoil has performed two Na-silicate well treatments at the Gullfaks field (one in 1993 and one in 1994).[5] The results for the first test was presented in may 1995 to have been an economical success with an incremental oil recovery of 46686 Sm^3.

Scaling in some injectors and need for pressure support has made gel treatment less attractive at the down-dip area of the Gyda field at present. However, gel treatment is considered to have a potential in reducing water production and improving sweep in the future.

Results

The technical contributions of the research on polymer gel within this RUTH subprogram can be summerized as:

1. Gel systems for deep emplacement or high temperature producer treatment were identified. This extend the possibilities for use of gel technology in field applications in North Sea reservoirs.
2. Guidelines for improved placement techniques are presented. Two techniques are recommended: (a) dual injection of gelant and a protective fluid and (b) preflush of a protective fluid with high viscosity followed by injection of a low viscosity gelant. Both methods can be used to place the gelant in the desired reservoir zone. The first method requires coiled tubing, the second makes use of reservoir heterogeneities.
3. An evaluation of three pilot candidates in three different sandstone reservoirs were performed.
4. An evaluation of environmental harmful effects by IOR-chemicals were performed.

Future Outlook

Several of the larger fields on the Norwegian shelf will gradually cease plateau production towards the end of the century (as the Statfjord and Gullfaks field).[4] As these fields become more mature, there will be an increasing challenge to improve the productivity of high water-cut wells and to improve sweep efficiency.

The most important challenge in the next years on the Norwegian shelf is to demonstrate the usefulness of the gel technology in field pilots.

In recent years there has been a tremendous development in advanced well technology. However, the technology for work-over and water or gas shut-off for such wells needs to be improved. One interesting concept for further development is self-selective gels that reduce the permeability of water with little or no impact on the oil permeability. In general, there is a need for development of more environmentally benign gel systems.

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THE SURFACTANT SUBPROGRAM

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Introduction

At the start of the subprogram, chemical flooding of oil reservoirs did not look very promising, even though the technical potential for the method was believed to be very high. Many of the oil reservoirs in the North Sea are waterflooded, and it was assumed that the waterflooded capillary trapped oil was in the range of 30% of the pore volume. It appeared that the main challenge of the surfactant subprogram was to improve the efficiency of the chemicals used, i.e. more recovered oil per kg chemicals injected. Unfortunately, the cost of the chemicals increases as the efficiency increases since the most efficient surfactants for micellar flooding are more complicated to synthesize in large quantities.

Until 1990, no offshore field pilot for surfactant flooding had been performed anywhere in the world. For North Sea reservoirs, the flooding conditions (rather large temperature gradient, large distance between the injector and the producer, high salinity seawater) require a robust chemical system to ensure optimal recovery of oil. A step forward in the research of micellar flooding is to compose a chemical system which lowers the technical risk and still is able to recover at least 50% of the capillary trapped oil.

Goals

The main goals for the subprogram have been:

1. Give clear technical and economical success criteria for chemical flooding of North Sea sandstone reservoirs and procedures for proper evaluation of a field pilot.
2. Give an evaluation of ethoxylated sulfonates as potential EOR-chemicals for North Sea sandstone reservoirs.
3. Evaluate the use of chemicals in chalk reservoirs to increase the imbibition of water.

Projects

The subprogram is divided into five projects.

Chemical flooding of chalk reservoirs

The objective is to evaluate the use of surface active chemicals to improve the imbibition of water into low permeable, fractured chalk reservoirs exhibiting different wettabilities.

A preliminary study was performed to evaluate the potential for chemical flooding in fractured chalk reservoirs, using a dual porosity simulator. Imbibition experiments at laboratory conditions were conducted using small and long cores with and without surfactant to determine the imbibition mechanism, i.e. capillary versus gravity-forced imbibition. The wettability was changed by using different mixtures of n- heptane and Ekofisk crude oil. Imbibition tests, in the secondary and tertiary mode, were conducted at reservoir conditions (130 °C and 4000 psi) using cores from the Tor formation in the Ekofisk field, live crude oil, and brine with a cationic surfactant.

Technical and economical conditions for success

The objective was to evaluate the economical and technical potential of surfactant flooding, and four major North Sea fields were selected for a screening study. Relevant input data were obtained from the laboratory experiments.

Location of possible pilot areas was identified. The influence of factors like interfacial tension, CDC curve, adsorption, and polymer concentration, on the technical and economical potential was investigated based on full field simulation studies.

Efficiency of surfactants

The objective was to evaluate the efficiency of ethoxylated/propoxylated anionic surfactants in terms of phase partition, adsorption, chromatographic separation, and surfactant-polymer interaction in low tension polymer water floods, LTPWF. This was the main project within the program, and it was divided into two activities.

The effect of polymer on the adsorption of surfactant was tested by core flood experiments. The tests were performed in the two-phase state, and the potential of polymer to act as a sacrificial adsorbate towards the surfactant was quantified. Adsorption mechanisms in long-term flood experiments were discussed.

The mechanism for oil recovery by co-injecting surfactant and polymer was studied both in the three-phase and in the two-phase state. In the three phase area, a polymer gradient was tested to create a proper phase transition. In most cases, however, the floods were conducted in the two phase state as a LTPWF. An effective surfactant of the type alkyl-propoxy-ethoxy-sulfate was synthesized. The interaction between the surfactant and the polymer in the aqueous phase and at the solid/liquid interface was important in understanding the principle of LTPWF.

Phase studies at reservoir conditions

The objective was to study the multiphase behavior of oil-brine-surfactant systems at reservoir conditions using PVT measurements. Special attention was given to the effect of high temperature, the properties of the oil, and anionic surfactants of the ethoxylated sulfonate type.

The multiphase behavior was studied in the temperature range 80-180°C and pressure range 200-1000 bar. An alkyl-xylene-sulfonate dissolved in NaCI-brine was used as surfactant solution in combination with different types of oil.

The surfactant product As 142 from Berol was used as surfactant in seawater in combination with live crude oil. The phase properties were discussed in relation to changes in temperature, pressure, and gas-oil ratio.

Criteria for low values of S_{orw}

The objective was to identify reservoir parameters that are important to obtain low S_{orw} values in waterflooded oil reservoirs. The evaluation of the optimal flood condition was based on a literature study and some vertical flood experiments related to the effect of pH and asphaltenic material in the oil.

From laboratory to field applications

At the start of the subprogram, Statoil planned for a surfactant pilot in the Gullfaks field, and it was suggested to cooperate closely with the surfactant program. In 1994 Statoil cancelled the plans for the surfactant pilot, and none of the other oil companies participating in the program had plans for surfactant pilots. Within the subprogram, however, four possible surfactant pilots were modeled and the oil recovery was discussed in relation to the criteria for economic and technical success.

Results

Different mechanisms for oil expulsion from low permeable chalk (2-3 mD) by imbibition of water at low interfacial tension (0.02 mN/m) have been identified. In water-wet systems, a countercurrent fluid flow is observed at the start indicating an imbibition process governed by capillary forces. Later in the process, gravity forces are dominating, and the oil is produced at a very slow rate. Compared to imbibition of pure water, the low IFT process is probably too slow for field applications. The oil expulsion rates were discussed in terms of gradients in the interfacial tension (Marangoni effects). In mixed-wet systems, it was observed that surfactants may prevent the imbibition of water probably due to adsorption. In a oil-wet system, the oil was displaced by a spontaneous drainage process at low IFT. Thus, the oil expulsion from this type of matrix was improved with surfactants only in the case of an oil-wet system.

Simulation data from four conceivable chemical floods in the North Sea confirm that the economics of the process fails, mainly due to early breakthrough in the high permeable zones. Based on an oil price of 20 US$/bbl calculations showed that the price of the surfactant must be less than 10 NOK/kg for two of the reservoirs, and close to 15 NOK/kg for the two others, in order to recover a significant fraction (25%) of the actual technical potential.

It was well documented from laboratory experiments that due to improvements in the efficiency of the surfactant, more that 50% of the waterflooded residual oil was recovered by a LTPWF, i.e. by a two-phase displacement. It was also observed that large micellar aggregates had a negative effect on the flow performance in a LTPWF process, and a decrease in the oil recovery was noticed in the presence of polymer. Thus, the chemical understanding of the surfactant-polymer interaction mechanism is crucial. In reservoir cores of high clay content, the polymer was observed to decrease the adsorption of the surfactant. In model cores (Berea and Bentheim), the equilibrium adsorption of surfactant was not affected by the polymer.

New important knowledge about the multiphase properties of surfactant-oil-brine systems at high temperatures was obtained. In the presence of anionic alkyl-aryl-sulfonates, the phase transition was determined by the heavy end fraction of the oil system.

Criteria to obtain low waterflooded residual oil saturation, S_{orw}, in sandstone reservoirs were identified by literature studies and discussed in relation to reservoir conditions in the North Sea. It is concluded that film drainage by gravity forces probably is active in North Sea sandstone reservoirs.

Prospects

Presently, the cost of robust chemical systems and the low oil price imply that traditional chemical flooding of offshore sandstone oil reservoirs is not to be recommended. Furthermore, the major oil reservoirs in the North Sea are today waterflooded to give S_{orw} values in the range of 10-20%. The technical potential for chemical flooding is then reduced drastically.

The use of chemicals to improve the oil displacement by water in fractured, oil-wet, low-permeable chalk reservoirs is an area for further research, and should be completed, in order to fully understand the use of chemicals in this process.

Film drainage by gravity forces is believed to be an important process in obtaining low S_{orw} values in the field. The process is slow, and it is difficult to study in the laboratory. Knowledge about the relationship between surface active material and the rate of film drainage may shed further light on the process.

Well stimulations by means of surfactants are described in the literature. It should be useful to study the potential of the recent developed surfactant systems to dissolve precipitated asphaltenes in the formation close to production and injection wells.

Nomenclature

CDC Capillary desaturation curve

IFT Interfacial tension

LTPWF Low tension polymer water flood

S_{orw} Waterflooded residual oil saturation

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THE MICROBIAL METHOD SUBPROGRAM

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Introduction

Increased oil recovery by the use of bacteria, is often termed MEOR or MIOR (Microbial Enhanced/ Improved Oil Recovery). The use of bacteria to recover oil from oil reservoirs was first proposed by Beckman in 1926. [1,2]; Historically, bacteria has been regarded as a nuisance in the petroleum industry, as some generate hydrogen sulfide under the conditions generic to waterflooded oil reservoirs. [3,4] Microbial methods are regarded as tertiary recovery techniques. The temperature and pressure windows limiting their application expand with the growing body of reports on the subject. Currently, the technology has not reached field application in the Norwegian sector of the North Sea. In the UK sector microbial technology is undergoing field trials in the Beatrice and the Ninian fields. Several microbial methods may be used in North Sea fields. Some researchers study aerobic processes, other anaerobic processes, such as the BOS [5] or the SIFT [6] processes.

Goals

The goals of the subprogram were (1) to acquire experience and develop expertise in microbial technology pertinent to IOR, (2) to perform laboratory experiments to study mechanisms and process efficiency. The important issue was to demonstrate practical, controllable processes that result in increased recovery.

Scope of Work

Two mechanisms with an intuitive potential as IOR techniques were initially selected for investigation. Based on the equation

$$N = \frac{\mu \cdot v}{\sigma}$$

the capillary number may increase by either a reduction in the interfacial tension (σ) or by an increase in the viscosity (μ) of the mobile fluid. Increased microscopic displacement of oil may be expected if the capillary number is increased. In an early phase of the project, coreflooding studies showed that residual oil was displaced when native seawater bacteria, supported with limiting nutrients, was allowed to interact with the water/oil/solid phases. This process required supply of oxygen. Usually, injection waters in the North Sea fields are deaerated prior to injection, consequently we focused on anaerobic processes. The scope was narrowed, and a process relying on microbial in situ production of surface active components was not pursued further.

Poor sweep efficiency due to permeability contrasts is a problem in many North Sea sandstone reservoirs, and premature water breakthrough is often the case. The macroscopic sweep efficiency may be improved by reducing the permeability of such thief zones. Water diversion techniques look promising, and is attractive as a microbial technology as it only involves production of biomass in the thief zones. In our work we investigated how biomass could be selectively generated, in sufficient quantity in high permeable regions of a reservoir, to divert water into unswept zones. The method includes a technique that mitigates or negates secondary effects related to sulfate-reducing bacteria. The method is based on utilizing native, nitrate- reducing sea water bacteria, to grow and multiply in a reservoir matrix. Critical parameters pertinent to the technology were studied: (1) microbiology: characterization of nitrate-reducing bacteria in injection waters, screening of nutrients, size and morphology of sea water bacteria, polymer production; (2) transport and growth of bacteria in porous media: micro models and sand packs with different length and permeability.

Results

The use of nitrate to mitigate and disfavor conditions where biogenic sulfide is generated, was successfully applied in all our experiments. The technique holds promise for wide application. The development of the Automated Micro visual Observation and Reaction System (AMORS) as a tool to study microbial growth on the pore level, was an important achievement. This tool may be used in further studies on mechanisms involved in microbial oil recovery.

Polymeric material, that many bacteria produce, influences the rate of plugging in a porous matrix. The nitrate-reducing bacteria found in sea water include species that produce such material when provided with proper nutrients.

Selective plugging with biomass is a technology that needs to be optimized prior to a field application. Numerous publications on the subject verifies that bacteria block high permeable streaks preferentially and consequently divert water. Transportation of nutrients and removal of products that slow down the growth in the pores are the key challenges for this process. The size of the pore channels seems to have an important influence on the process. The pore size and pore size distribution that is appropriate for the process, needs to be determined. Water profile modification by the generation of biomass is considered a realistic alternative, but it may only be used in near well zones.

Future Outlook

Microbial methods are attractive basically because they are inexpensive alternatives to chemical treatments, especially in mature fields. The success or failure of microbial methods is linked to the flow pattern of the water in the porous matrix, and the water injection protocol. Knowledge about growth and behavior of bacteria in oil reservoirs may thus to a large degree be inferred from models describing flow patterns taking into account pore size and distributions. More research should therefore focus on this large scale perspective. The fact that oil reservoirs undergoing waterflooding can gradually develop problems with souring, clearly demonstrates that a better general knowledge about these phenomena is required. Such knowledge offers ability to predict souring outbreak, and to maintain safe working environments. Future research should therefore incorporate investigations aiming at avoiding souring, and understanding microbial techniques that help improving oil recovery or reducing water cuts. Either case should be economically beneficial.

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PROJECT SUMMARIES

THE COMBINED GAS-WATER INJECTION SUBPROGRAM

AND

THE GAS FLOODING SUBPROGRAM

THE EFFICIENCY OF COMBINED GAS WATER INJECTION PROCESSES

Tor Anderson, Jan-Ivar Jensen, Per Arne Slotte, and Arild Solheim, IKU Petroleum Research

Abstract

Poor sweep efficiency and early breakthrough is of major concern in processes involving gas flooding. Sweep efficiency may be improved by combined gas/water (CGW) injection.

The present paper deals with the effect of reservoir heterogeneities and operational constraints on CGW injection performance in the setting of a fluvially deposited (channel sand) reservoir. A reservoir simulation study is presented. First, a small part of the reservoir, representing a single conducting channel, is studied with respect to the importance of permeability heterogeneities. Secondly, a larger part of the reservoir is selected. The effect of operational parameters and constraints are studied, and one of the main issues is to study the effects of introducing a high-permeability channel connecting the injector and producers. Different strategies to counteract the reduced performance is evaluated.

Some of the main conclusions from the present work are:

- Increased variance in heterogeneity extend the gas/water mixed zone.
- The segregation model of Stone seems to be sufficient for a rough estimation of the size of the mixing zone.
- Gas in combination with water injection has a positive effect on the recovery.
- High permeable channels have a larger influence in the case of single fluid injection then for WAG injection.
- In the case of high GOR, reperforation has a positive effect.
- A change to water injection only can be effective after an initial WAG period.

GAS MOBILITY DURING THREE PHASE FLOW IN COMBINED GAS/WATER INJECTION PROCESSES

Per Kristian Munkerud, IKU, Jean Patrick Duquerroix, IFP and George Virnovsky, RF - Rogaland Research

Abstract

The paper is devided into three parts. In part one three-phase relative permeabilities were measured by steady state and displacement methods. The recovery of oil and the mobility to gas were found to be lower at non-spreading than at spreading conditions. During alternating or simultaneous gas/water flow at high water saturations, the mobility was significantly lower than what can be assumed for three phase flow based on standard gas/liquid two-phase relative permeability (more pronounced for low permeability). Experiments at reservoir conditions confirmed this observation.

In the second part, a brief discussion has been made on the influence of lithofacies, correlation length, permeability anisotropy ratio and slug size on WAG-performance. For two-layer reservoirs (WAG-ratio = 1), larger slugs gives higher oil recovery. The influence of the location of heterogeneity on oil recovery is substantial.

In the third part, the results of an analytical and numerical study of the stability of gas-oil-water displacement fronts are presented. The flow equations are simplified by averaging in the dip- normal direction (vertical equilibrium) to give analytical expressions for three-phase pseudo relative permeabilities and capillary pressures for a stratified reservoir. A similarity transform results in a set of two coupled, ordinary differential equations and a simple technique is presented to identify the traveling-wave solution when certain conditions are met. The shape of the front is calculated, and the technique verified by numerical simulation.

WAG INJECTION IN COMPOSITE LAYERED CORE AND DIFFUSION IN FRACTURED STRUCTURES

Idar Akervoll and Per Arne Slotte, IKU Petroleum Research

Abstract

Physical and numerical modeling are presented of CGW (combined-gas-water) and WAG (water-alternating-gas) injection experiments in a composite layered flow model (part 1), and analysis of diffusion contribution to the total transport in fractured structures (part 2).

The physical flow model consists of a sandstone half-core mounted on top of another sandstone half-core (comprising a permeability contrast along the length axis) with sieved sand in between, all casted into a layered consolidated core. Miscible gasfloods with model fluids and miscible WAG injection at reservoir conditions were modeled physically and numerically and by use of compositional simulators. The miscible WAG experiment raised the recovery by 36% of STOIP beyond that of waterflooding.

Analytical calculations are presented on the contribution from diffusion to the recovery from miscible gas injection in naturally fractured reservoirs in the second part of this project. The main result is the identification of three dimensionless parameters that may be used to determine how diffusion should be included into simulations.

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PHYSICAL GAS/WATER SEGREGATION MODEL

Torleif Holt and Frode Vassenden, IKU Petroleum Research

Abstract

This paper gives an overview of a project that has involved the design and construction of a two dimensional physical laboratory model, and experimental studies of gravity segregation of fluids injected into the model. The physical model is constructed after new principles. It has been filled with glass beads in the experimental work. Two sets of injection fluids were used, gas/water and a model

system having low interfacial tension (IFT) in order to scale the experiments. Based on relative permeability data measured for both fluid systems in a one dimensional pack of the same glass beads, flow zones for mixed and segregated flow were predicted by using the Stone-Jenkins segregation model, and by numerical simulations. For the low IFT model system, the measured and predicted flow zones are in good agreement, both for co-injection and alternating injection. For injection of gas and water the experiments were dominated by capillary forces, which are not included in the Stone-Jenkins theory.

The results obtained show that relative permeability data measured in standard one- dimensional core flooding experiments, involving co-current flow of the phases, are also representative for describing gravity segregation of the two phases, a process that has elements of counter-current flow. Reservoir simulation models assume that standard relative permeability data can be used to model gravity segregation. The results obtained in this work, although only proven valid for the conditions tested, supports this assumption. This increases the confidence in the extension of segregation zones predicted by reservoir simulators.

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SNORRE WAG PILOT

Per Arne Slotte, IKU Petroleum Research - Hogne Stenmark and Terje Aurdal, Saga Petroleum

Abstract

A WAG injection pilot was initiated in February 1994 in the Snorre Field. This allowed for an immediate increase in oil production, as gas export restrictions no longer limited oil rates. In 1994, the total acceleration of oil production due gas injection was estimated at 1.5 MSm^3.

Early gas breakthrough was experienced in one well. There has been little or no production of injected gas in the other producers.

This paper summarizes the Snorre WAG pilot history and the RUTH involvement therein. The RUTH involvement has been related to a compositional simulation study.

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BRAGE WAG PILOT

Jan-Ivar Jensen, Helge Nesteby[1], and Per Arne Slotte, IKU Petroleum Research - Eirik A. Berg, Norsk Hydro

Abstract

The Fensfjord reservoir in the Brage field has had an ongoing two injector WAG pilot since late 1994. The reservoir is highly stratified with large permeability contrasts and calcite barriers. This paper summarizes the history and experience up to date, and the RUTH involvement in the pilot.

The paper is divided into three main parts: First, the history and experience with the Brage WAG pilot up to date is summarized. Second, a simulation study on the effects, on WAG performance,

of varying relative permeability endpoints is described. Finally, the results from stochastic simulations, followed by upscaling and flow simulations, to evaluate uncertainty is described.

Some of the main conclusions are:

- Segregation of gas and water dominate the WAG process.
- The reservoir layers are dominated by water flooding at critical gas saturation.
- There is a strong improvement (5%) in oil recovery using WAG injection compared to only water injection.
- The geological uncertainty results in a small uncertainty in recovery estimates.

[1] Currently at Geomatic

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DRY GAS INJECTION IN FRACTURED CHALK RESERVOIRS

Lars Øyno, Reservoir Laboratories - Curtis H. Whitson, Norwegian University of Science and Technology (NTNU) - Knut Uleberg, Norwegian University of Science and Technology (NTNU) - Andreas J Haldoupis, Norwegian University of Science and Technology (NTNU) - Anita Skjellanger, IKU Petroleum Research

Abstract

Gas injection in fractured chalk reservoirs has sometimes been regarded as inefficient due to early breakthrough of injection gas. However, if the pressure in the reservoir is increased, and a non-equilibrium dry gas is injected into the fracture system, compositional effects will be active between the gas in the fractures and oil in the matrix. The method is potentially well suited to fractured chalk reservoirs in the Ekofisk Area in the North Sea due to relatively small block sizes (10-100 cm).

Laboratory experiments have been conducted on composite cores at reservoir conditions using recombined reservoir fluids to investigate the potential of secondary recovery by gas injection. Gas was injected into a fracture/chalk system for pressures above the bubble point of the in-situ oil.

Results from experiments conducted on composite cores up to 60 cm long, together with simulation indicate gas injection at elevated reservoir pressures results in oil production by several mechanisms. Compositional effects contribute mainly to additional oil recovery. Gravity drainage has previously been regarded as an important recovery mechanism in this type of gas injection. Gravity drainage and capillary redistribution due to low IFT controls the final oil saturation in the core during gas injection. The time required to reach capillary/gravity equilibrium depends on oil/gas density difference, gas/oil IFT (absolute value and IFT gradients with depth), and molecular diffusion in both gas and oil phases.

Two constant volume diffusion experiments with Ekofisk stock-tank oil and methane were also conducted. The results of these experiments were used to obtain diffusion coefficients using a compositional simulator.

Correct diffusion coefficients are the key parameters for accurate interpretations and matching of the multicomponent (natural gases and crude oil) diffusion dominated processes. The simulations were compared and matched to experimental data by fine tuning the original diffusion coefficients. This was useful to confirm the validity of the extended Sigmund correlation.

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DRY GAS INJECTION AFTER WATER INJECTION IN FRACTURED CHALK RESERVOIRS

Lars Øyno, Reservoir Laboratories - Curtis H. Whitson, Norwegian University of Science and Technology (NTNU) - Andreas J Haldoupis, Norwegian University of Science and Technology (NTNU)

Abstract

Gas injection in fractured chalk reservoirs has sometimes been regarded as inefficient due to early breakthrough of injection gas. However, if the pressure in the reservoir is increased, and a non-equilibrium dry gas is injected into the fracture system, compositional effects may be active between the gas in the fractures and the more or less trapped oil in the matrix. The method is potentially well suited to fractured chalk reservoirs in the Ekofisk Area in the North Sea due to relatively small block sizes (10-100 cm).

Laboratory experiments have been conducted on single plugs and composite cores at reservoir conditions using reservoir fluids to investigate the potential of tertiary recovery using gas injection. Gas was injected into a fracture/chalk system for pressures above the bubble point of the in-situ oil.

Results from experiments conducted on composite cores up to 60 cm long indicate that compositional effects can contribute to production of 20 - 30% of remaining oil, and that time scales are within reasonable limits.

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EVALUATION OF TERTIARY FLOODING IN FRACTURED CHALK USING NUMERICAL SIMULATION MODELS

Thor M. Hegre and Steinar Kristiansen, Geomatic

Abstract

Several large fractured chalk fields are located in the southern part of the Norwegian sector of the North Sea. Production commenced from these fields during the seventies and they are still contributing significantly to the Norwegian oil production. All these fields are either currently producing or have

been produced by pressure depletion. Rock compaction has significantly contributed to the oil production. Water injection has been shown to enhance the oil production from the Ekofisk field. The potential for further improvement of the oil recovery by tertiary flooding, either by gas or water, is addressed in this work. It is shown that the oil recovery in fractured chalk fields may be substantially enhanced by tertiary flooding. However, a significant production of injected fluid, either water in a tertiary gas flood or gas in a tertiary waterflood, is inevitable. Thus a long production period is required to recover this additional oil unless an active well drilling and stimulation program is initiated. The work reported here is based on typical rock, fluid and saturation data from Norwegian fractured chalk fields. Field specific evaluations, including the economic aspects, are required to make recommendations if a tertiary flood is a viable project.

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DUAL POROSITY, DUAL PERMEABILITY FORMULATION FOR FRACTURED RESERVOIR SIMULATION

K. Uleberg and J. Kleppe, Norwegian University of Science and Technology (NTNU)

Abstract

This study reviews key physical mechanisms and calculation methods for modelling of fluid flow in North Sea fractured reservoirs. The main matrix-fracture fluid exchange mechanisms described are gravity drainage, capillary imbibition and molecular diffusion. Important issues such as capillary continuity between matrix blocks, reinfiltration of fluids from higher to lower blocks and effect of block shape on flow processes are also addressed.

Simulation studies of water-flooding in fractured reservoirs are reported for the purpose of identifying the effects of gravity and capillary forces on oil recovery. Included are studies of effects of capillary continuity and degree of wetting. The results show that for intermediately wetted systems, such as the Ekofisk reservoir, capillary continuity has a major effect on oil recovery.

Laboratory processes involving high pressure gas injection in fractured systems have been studied by compositional simulation. The results show that changes in interfacial tension caused by diffusion, may have dramatic effects on oil recovery.

Computational aspects of fluid exchange processes are discussed, including conventional dual porosity

formulation, use of matrix-fracture transfer functions, and detailed numerical calculation. The only solution to more representative modelling of flow in fractured reservoirs is more detailed calculations. A multiple grid concept is proposed which may drastically increase the detail of the simulation.

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ENERGY AND ENVIRONMENTAL EFFECTS IN TERTIARY GAS INJECTION

Erik Lindeberg and Øistein Glasø, IKU Petroleum Research

Abstract

Most of the Norwegian oil fields are being waterflooded. The production will inevitably cease due to excessive water cut. Tertiary gas injection is one of the few alternatives to recover some of the residual oil (50% to 70% of OOIP). If a massive gas injection should be adopted for all these reservoirs, the energy demand and the corresponding environmental offshore industry could increase. This industry already has a large share of the total Norwegian greenhouse gas emissions (23% of total CO_2 in 1994). Massive tertiary gas injection has therefore been analyzed and the results shows that no negative environmental effect would be anticipated if hydrocarbon gas is used as injection gas. If CO_2 is used as injection gas, the only realistic source would be coal power plants in the EU. Use of industrial CO_2 will give a large reduction of global CO_2 emissions (168 Mton/year, or 50% of the total CO_2 emissions from German coal power) and insignificantly increase of the Norwegian emissions. If massive nitrogen injection should be adopted, however, the Norwegian CO_2 emissions would be more than doubled due to the large energy requirement involved in separating nitrogen from air.

The availability of hydrocarbon gas is compared to the amount of gas needed in a large scale tertiary gas injection scenario. The results show that if significant amount of residual oil is to be recovered by this method a decision to allocate to some of the remaining gas resources for this purpose. The most gas has already been contracted. If not sufficient hydrocarbon gas is available the tertiary production potential has to be realized with other injection gases, i.e., nitrogen or carbon dioxide. Comparing the energy content in the extra oil with the energy input in the process, gives the energy balance. For hydrocarbon gas, a net energy gain depends on to the extent to which tertiary injected gas can be recovered after the injection period. It is uncertain how much of this gas can be produced after a long secondary and tertiary injection period. The CO_2 injection will give a large net energy gain. Economical considerations have

not been taken into account in this study.

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COMPOSITIONAL RESERVOIR SIMULATION - A METHOD FOR UPSCALING

Dag Wessel-Berg and Odd Steve Hustad, IKU Petroleum Research

Abstract

A general method for scaling three-dimensional three-phase compositional flow based on a fine scale simulation has been developed The algorithm reads static and time dependent petrophysical data given by a compositional reservoir simulation, the fine scale simulation, and averages all necessary data, except relative permeabilities and capillary pressures, to a pre-defined coarse scale description of the simulation scenario. At given coarse scale timesteps, "optimal" coarse scale relative permeabilities and capillary pressures values are determined from a global match procedure. The method matches on coarse scale gridblock mole numbers of all the components (including water) simultaneously in the whole coarse scale reservoir. A computational effective "alternating least square error method" is applied for handling the corresponding non-linear minimization problem of determining coarse scale relative permeability and capillary pressure values.

This paper presents an outline of the scaling procedure and examples from the scaling method illustrating the variability of the pseudo functions on parameters like gridblock sizes, rates, gravity, capillarity, and phase behavior (vaporization).

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OIL RECOVERY BY GRAVITY DRAINAGE DURING GAS INJECTION

Hermod Skurdal, Odd Steve Hustad and Torleif Holt, IKU Petroleum Research

Abstract

This paper presents the results from six gravity stable gas injection experiments in 1.2 m long water flooded sandstone cores. All experiments were performed; for time periods of 50 to 170 days, close to ambient conditions, and with different combinations of spreading and wetting characteristics. The effectiveness of oil recovery by gravity drainage for the different flow conditions are shown. A mixed wet paste was placed on the outlet of each core to eliminate end effects. Experimental techniques for elimination of capillary end effects are discussed. Saturation profiles in the cores were determined at the end of each experiment.

The final oil saturations obtained from the experiments varied from 3% to 8% pore volume. The results do not allow unambiguous conclusions to be drawn regarding the effect of wettability and spreading characteristics on oil recovery. All modes gave high oil recoveries.

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A CONSISTENT FORMULATION FOR THREE-PHASE RELATIVE PERMEABILITIES AND PHASE PRESSURES BASED ON THREE SETS OF TWO-PHASE DATA

Odd Steve Hustad and Anne-Grethe Hansen, IKU Petroleum Research

Abstract

A three-phase formulation of relative permeabilities and phase pressures for reservoir simulators is presented. The formulation is based on three sets of two-phase data and properly accounts for six, two-phase, residual or critical saturations. The model uses only two-phase data and an interpolation technique to obtain three- phase properties by a systematic weighing procedure based on the saturations and end point values. The procedure ensures smooth transitions of relative permeabilities and phase pressures for processes that go from any two-phase state to another two-phase state by way of the three-phase region.

Successful simulations with the formulation are shown and compared to results from a vertical gas

flooding experiment exhibiting three-phase flow and having extensive gas injection.

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FIELD SCALE SIMULATIONS OF OIL RECOVERY BY GAS INJECTION UNDER DIFFERENT WETTING CONDITIONS

Odd Steve Hustad, Jan-Ivar Jensen, Anne-Grethe Hansen and Hermod Skurdal, IKU Petroleum Research

Abstract

Field scale simulations have been conducted to investigate the influence of the reservoir's wetting condition on oil recovery for gravity stable gas injection processes. The effect of using different fluid models has also been studied.

Three vertical core flooding experiments have been performed to establish the drainage conditions for spreading oils in high permeable sandstones. The cores were either water wet, mixed (water and oil) wet or oil wet.

A newly developed three-phase formulation for relative permeabilities has been implemented into the commercial simulator, Eclipse 300, and applied to reproduce the experimental observations. The resulting relative permeabilities that reproduced the oil and water recoveries from the core flooding experiments were then applied in the field scale simulations.

A satisfactory reproduction of the experimental results was achieved with the relative permeability formulation. The field scale simulations show that the oil recovery is significantly different under the various wetting conditions. The drainage of oil is most favorable for the water wet condition and least favorable for the mixed wet condition. It is also seen that phase behavior models play a significant role in modeling the oil recovery.

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PROJECT SUMMARIES

THE FOAM SUBPROGRAM

NORTH SEA PRODUCTION PROBLEMS AND FOAM PROCESS SOLUTIONS

Jan Erik Hanssen and Leonid M. Surguchev, RF - Rogaland Research

Abstract

This paper reviews the application of foam for improved oil recovery and reduced gas production and highlights key features of selected foam processes. Recovery and production problems caused by the high mobility of gas are categorized and the global field experience with foam reviewed, emphasizing application to North Sea fields. Physical-model experiments are reviewed that illustrate two foam processes of relevance. The field-scale potential of the most applicable processes is evaluated for a generic reservoir case. Finally, some results on the possible use of foam in fractured reservoirs and in horizontal wells are summarized.

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PHENOMENA CONTROLLING FOAM PROPERTIES

Torleif Holt and Frode Vassenden, IKU Petroleum Research - Mariann Dalland and Jan Erik Hanssen, RF - Rogaland Research

Abstract

This paper summarizes the results from several activities within RUTH-Foam that have addressed fundamental properties controlling the behavior of foam in porous media.

The first part of the paper gives a brief review of some important properties for static and dynamic foam stability. Results from measurements of the temperature dependence of the disjoining pressure, from measurements of disjoining pressures in non-aqueous foam systems, and from the measurement of surface viscosity for two surfactant systems are presented. The results are discussed in relation to experimental conditions during foam screening tests and to results obtained in core flooding experiments.

Results from observations of foam behavior in realistic pore-size micromodels are given in the second part of the paper. These observations demonstrate that the dimensions of the micromodel can affect conclusions concerning mechanisms that controls the properties of foam in porous media. They also indicate a potential for improvements in foam modeling through application of results from realistic pore-size models as phenomenological basis.

The third part of the paper treats the stability of foam in the presence of oil. Mechanisms by which oil may destabilize foam, and thermodynamic indicators of this, are discussed and seen in relation to experimental results.

Finally, studies of gravity segregation of gas and surfactant solution during foam injection into a two-dimensional laboratory model have been performed. The results obtained suggest that foam segregates slower than predicted for normal fluids.

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FOAMING AGENT SELECTION

Mariann Dalland and Jan Erik Hanssen, RF - Rogaland Research

Abstract

This paper explains the principles of systematic product screening and qualification and evaluates the influence of the various foam, process and experimental parameters on the reliability of product selection. Two major objectives in RUTH-Foam were to define critical screening parameters and develop a general screening procedure; the first was achieved but the second was found to be impossible because of the process/mode dependence of foam properties.

Known critical parameters that should be accounted for are; the porous medium type, length of porous medium, the reservoir temperature, brine and presence of oil, and the experimental mode that the experiments are conducted under. The importance of these parameters is discussed.

High performance foams identified often have a relatively high unit cost. Three different ways to enhance foam performance, starting from low cost foamers, have been studied.

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FOAM MODELLING TECHNIQUES

Frode Vassenden and Arild Solheim, IKU Petroleum Research

Abstract

This paper reviews existing foam modeling tools, including an evaluation of the ability of the models to reproduce aspects of foam behavior that are critical for foam treatments on the reservoir scale. Specifically, the Eclipse foam option, the foam option of STARS, and the mechanistic Berkeley model are presented and evaluated. STARS seem to be the most flexible and reliable tool evaluated. The Eclipse foam option is built on an incorrect physical basis, while the Berkeley model is insufficiently developed for reservoir simulation. As background for the discussion, a description is given of physical phenomena that are essential for the understanding of foam behavior in porous media. Finally, up-scaling of foam parameters is discussed.

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PERFORMED AND PLANNED FOAM FIELD TESTS

Leonid M. Surguchev and Jan Erik Hanssen, RF-Rogaland Research, Arne Skauge and Morten G. Aarra, Norsk Hydro, J. Jeffrey Buckles, Mobil, Idar Svorstøl, Saga Petroleum, Helmut Niko, Shell,

Trond Rolfsvåg, Statoil

Abstract

This paper gives results quantifying the reservoir potential and evaluating specific field application of foam processes. Treatment of high-GOR production wells to remedy coning and cusping, and WAG injectors to divert injectants to less well flooded zones are reported. A fully-featured reservoir simulator with an empirical foam option is used. History matching and evaluation of recent foam pilots were performed and the sensitivity of the foam processes to reservoir and foam parameters evaluated. Against gas coning, a treatment radius of 10 m and a mobility reduction factor of 30 may in a favorable case be sufficient to delay gas breakthrough for several months. However, in order to be effective against gas cusping, the foam must be stronger and oil- tolerant. For injectant diversion, foam application by alternate injection of surfactant solution followed by gas was found to offer a significant potential of improving WAG process efficiency. If properly applied, foam can improve efficiency of gas based IOR methods, reduce gas production, improve sweep efficiency and increase oil production.

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PROJECT SUMMARIES

THE POLYMER GEL SUBPROGRAM

THE CHALLENGE OF PLACING GELS IN PROBLEM WELLS

Jostein Kolnes and Svante Nilsson, RF - Rogaland Research

Abstract

The system studied is designed for deep injector treatment, and can also be applied for treatment of a hot producer. Hence it consists of polymer at a rather low concentration (0.5 weight% polyacrylamide) to ensure high mobility of the gelant. The crosslinker is chromium (oxidation state 3) protected by malonic acid, in order to slow down the gelation process, and to reduce retention.

Large differences in the gelation process are observed depending on whether the gelation occurs in bulk or in a core. Also, large differences are observed between different cores. Here two outcrop sandstones (Berea and Bentheimer), and a North Sea reservoir sandstone have been used. The gelation process shows variations in: gelation time, critical chromium concentration, and changes in pH during gelation. Three important properties of the core material causing this behavior have been identified: 1) content of carbonates (mainly $CaMg(CO_3)_2$ and $CaCO_3$) which controls the pH, and thereby the gelation time the stability of the gel, and precipitation of chromium; 2) content of iron (mainly as $FeCO_3$) - which affects the stability of the polymer; and 3) The amount of clays, which governs the cationic exchange capacity, and thereby the retention.

The gelant behavior in the core material has to a large extent been reproduced in bulk by adding appropriate amounts of kaolinite, and the minerals/chemicals mentioned above, to the bulk solution. It is also shown how to compensate for these changes induced by the core material.

The results from our study show that it is extremely important to know the mineral composition of the reservoir rock before a gel treatment is applied. This knowledge will enable us to avoid breakdown of our gel in regions where we want it to block water, and the prediction of shut-in time in case of a producer treatment is improved. In addition our findings suggest that for reservoirs where there is a good correlation between low permeability and high clay content of the sand, which often is the case, one might avoid zone isolation when placing the gelant. Even for a relatively high value of vertical to horizontal permeability, a successful gel treatment seems possible with bullhead injection. The treatment can be used both for injectors and producers, and the effect will increase with increasing depth.

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POLYMER GELS FOR DEEP EMPLACEMENT - COVALENT CROSSLINKING

Kjell Olafsen, Eddy W. Hansen, Kjetil H. Holm, Dag M. Jahr and Aage Stori, SINTEF.

Abstract

Alternative crosslinkers to glutaraldehyde have been evaluated for delay of gel formation in the polyvinyl alcohol (PVA)/dialdehyde system, thus making the system more suitable for deep emplacement in thief zones in an oil reservoir. A gel treatment can improve the sweep efficiency, and deep emplacement of gel is desirable in reservoirs with vertical communication.

Viscometry and Nuclear Magnetic Resonance (NMR) have been used to study gelation rates and activation energies for different PVA/crosslinker formulations. It was found that by using the crosslinker 2,5 dimethoxy - 2,5 dihydrofuran, it was possible to delay gel formation significantly as compared to gelation with glutaraldehyde.

Gravimetric studies have been used to study the stability of PVA gels with respect to syneresis at 120°C and 150°C (temperatures relevant for practical use in an oil reservoir). It was found that gels with 2,5 dimethoxy - 2,5 dihydrofuran as crosslinker had lower degree of syneresis at 120°C than gels crosslinked with glutaraldehyde. At 150°C gels crosslinked with 2,5 dimethoxy - 2,5 dihydrofuran dissolved, while gels crosslinked with glutaraldehyde were stable at pH = 7.

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GELANT TRANSPORT AND PLACEMENT IN HETEROGENEOUS RESERVOIRS

Bjørn Arne Kvanvik, Terje Litlehamar* and Arne Stavland RF - Rogaland Research,* Geomatic

Abstract

An evaluation of critical parameters for gel treatment of sandstone and chalk reservoirs is presented. Simulations were performed using reservoir models based on data from two North-Sea fields. In chalk formations, near well treatments were in general found to be detrimental for the injectivity and

productivity. Gel was found to be most efficient for deeper treatment and in cases with fractures with unfavorable fracture orientation. In sandstone formations, gel treatment was found to be most efficient when the displacement mechanism was dominated by viscous forces. Best results were obtained with the high permeable layers in the upper/middle part of the reservoirs and with some restrictions on vertical communication between the layers. Gel efficiency tended to increase with increasing permeability reduction and increasing slug size.

In layered sandstone reservoirs, crossflow between layers or communication through the completed well can cause gel to impair oil productive zones even if zone isolation is used. One main objective were to improve gel placement techniques so that gel penetration into oil productive zones can be avoided or at least be reduced. Two placement techniques are demonstrated in layered sand pack experiments: (a) dual injection of gelant and a protective fluid and (b) preflush of a protective fluid with high viscosity followed by injection of a low viscosity gelant. Both methods can be used to place the gelant in the desired reservoir zone. The first method requires coiled tubing, the second makes use of reservoir heterogeneities.

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THERMAL STABILITY OF THIN GELS

Torbjørn Tyvold, Svante Nilsson and Hildegard Tengberg-Hansen, RF - Rogaland Research

Abstract

Thermal stability of thin gels has been evaluated at 120°C and anaerobic conditions. This research is directed at gel applications in water injection wells for sweep improvement and in production wells for water shut-off. The experiments examine the effect of high temperature, salinity and lithology on gel stability.

Bulk tests have shown that partially hydrolysed polyacrylamide (H)PAM crosslinked with Cr^{3+} or Al^{3+} undergoes syneresis to a large extent at 120°C. A terpolymer based on (H)PAM, polyvinyl pyrrolidone (PVP) and acrylamido- propanesulfonate (AMPS), crosslinked with Cr^{3+} or Al^{3+}, at favorable polymer to crosslinker ratios, does not suffer from syneresis.

Bulk tests in a Gel Strength Tester show that as the gel synereses, the gel strength increases. When no syneresis occurs, the gel strength remains unchanged.

Sandpack floods show that as syneresis of the gel occurred, the residual resistance factor (RRF) decreased. The final RRF was still high, even though the degree of syneresis was high. The highest RRF was observed in the system that showed no syneresis. In sandpacks, the reduction in RRF with time was most rapid with Al^{3+} as a crosslinker. With chromium as a crosslinker, the gels were more stable.

The effect of the core lithology on thermal stability was investigated, applied several gel systems. The most promising systems are those based on (H)PAM or terpolymers crosslinked with chromium.

The effect of high salinity and clay content on gel stability was examined in bulk tests. The results show that the stability is independent of the clay content and the high salinity.

Adding acetate buffer to the gelant in reservoir cores, caused competitive ion complexation to occur, resulting in reduced gel strength.

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ENVIRONMENTAL HAZARDS FROM IOR-CHEMICALS

Berit Skjellerudsveen, RF - Rogaland Research

Abstract

The aim of this study is to increase the knowledge about toxicity and the quantities of IOR-chemicals that may be present in the produced water and the effects on the environment when discharged into the sea.

The authorities demand that offshore chemicals are tested for acute toxicity to three organisms, and for bioaccumulation and degradation. Also it was considered important to study what may happen with the chemicals in the reservoir.

A representative selection of polymer, and polymer-gel systems and of flooding and foaming surfactant systems, relevant for IOR-treatment of North Sea wells were tested for acute toxicity on the marine bacteria in the Microtox screening test.

Chromium-containing crosslinking agents were further tested for toxicity on three marine species.

One surfactant system and one polymer-gel system were chosen to be injected in the coreflooding experiments. The toxicity of the fluids produced in the experiments were tested.

The toxicity of the polymer- and surfactant systems alone is not high but when they are used during oil production they may influence the bacterial activity in the reservoir and interfere with the production water treating processes.

A literature review was performed to be able to evaluate the potential hazard associated with the application of chromium (III) in gel treatment pilots.

It is important to distinguish between use of chromium-containing gel systems and discharge of chromium to the sea. It can be justified that the discharge of chromium in produced water, resulting from the use of chromium as a cross-linking agent in gels, will be negligible.

The environmental effects of an accidental spill of chromium (III) are uncertain. The effect and fate of precipitated $Cr(OH)_3$ in the sediment should be studied further in more carefully designed experimental systems.

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PREPARATIONS FOR A GEL PILOT AT THE GYDA FIELD

Bjørn Matre and Bjørn Kvanvik, RF - Rogaland Research

Abstract

This paper describes an evaluation of gel treatment in a high temperature reservoir where permeability contrasts combined with thermal-induced fractures (TIF) result in poor vertical sweep efficiency.

The Gyda field is located in the Norwegian sector of the North Sea. It is a high temperature (154°C) sandstone reservoir. The water injection wells operate in low permeability rock, (average permeability is approximately 30 mD) and performance depends strongly on achieving very long fractures up to several hundred feet in length. The down-dip area of the reservoir is divided into two main structures. The bottom structure with the highest permeability takes most of the cold injected water and thermally induced fractures are assumed to be created in this structure.

Two different simulation approaches have been used to evaluate the gel treatment potential. In both cases multi phase, multi component reservoir simulation models were used which include a gel model and heat flow calculations. In the first approach (a) the TIF was simulated as a pseudo-fracture (static fracture) and in the second approach (b) a simulator that includes a geomechanical model was used allowing for growth of thermal induced fractures (dynamic fractures). Simulation shows that the gel treatment can change the shape and size of the fracture and consequently the effect of a gel treatment is closely linked to the TIF performance.

Core flooding experiments on Gyda reservoir cores have identified gel systems for injector treatment. The gel systems are transportable and can form gels with appropriate gelation times in Gyda reservoir rock.

All simulations of gel treatment show reduced watercut compared with corresponding water- floods. However, the oil production rate was also reduced. As a consequence the cumulative oil production was reduced. The simulations are run without a maximum watercut limit. Production wells have been shut in at watercuts ranging from 30% up to more than 90%. Gel treatment of a producer that otherwise would have been shut in due to high watercut, can extend the life of the producer.

Scaling around some injectors and the need for pressure support have made injector treatment by gel less attractive in the down dip area of the Gyda field at present, but gel treatment has the potential to reduce water production and improve sweep.

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GEL PILOT PROSPECT IN THE SNORRE FIELD

Arne Stavland, Arild Lohne, Bjørn Matre and Bjørn A. Kvanvik, RF - Rogaland Research - Tove Lie, Saga Petroleum.

Abstract

The potential for a gel treatment of producer well (P-13) in the Snorre Field was evaluated. Three different simulation models have been used, two radial models (Eclipse and one extended version of in-house modified UTCHEM) and one field scale Eclipse model. Gelation and gel placement for three different chemical gel systems (Maraseal, Xanthan/chromium and PVA/glutaraldehyde) were studied using the UTCHEM model. All systems predicted appropriate gelation times.

Incremental oil production for this well was about 20 x 10^3 Sm^3 and a corresponding reduction in water cut. The potential was significantly improved, however, by introducing fractures in the model or by reducing the tubing wellhead pressure.

Temperature control and the pH buffer capacity of the formation were found to be critical factors for successful gel placement design.

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AN EVALUATION OF POTENTIAL FOR GEL TREATMENT OF HORIZONTAL WELLS IN A SEGMENT OF THE GULLFAKS FIELD

Bjørn Arne Kvanvik and Hehua Zhou, RF - Rogaland Research

Abstract

This paper presents results from an evaluation of the potential for gel treatment of two horizontal wells in a segment of Gullfaks Lower Brent (Etive/Rannoch).

Water injection is the major drive mechanism for maintaining reservoir pressure above bubble point. Water override through high permeable lower Etive and upper Rannoch has resulted in limited sweep of the underlying Rannoch. Both near-well water shut off treatment of the producer and a deep injector treatment for sweep improvement were evaluated.

Almost no improvement was found for near well gel treatment of the horizontal producer.

Preliminary results indicate a large potential for gel treatment of the horizontal injector. However, some depressurisation of the segment is needed to obtain a positive effect of the gel treatment. Further studies regarding the effect of gel treatment of the fractured and horizontal injector are recommended.

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PROJECT SUMMARIES

THE SURFACTANT SUBPROGRAM

CHEMICAL FLOODING OF FRACTURED LOW-PERMEABLE CHALK RESERVOIRS

T. Austad, B. Matre and J. Milter, RF, Rogaland Research, A. Sævareid and L. Øyno, ResLab, S. Kristiansen and S. R. Jakobsen, Geomatic

Abstract

The present report gives a summary of the results obtained in the RUTH-Surfactant Chalk project. The objectives of the project were to evaluate the use of chemicals in chalk reservoirs to (1) increase the imbibition of water by changing the wettability; (2) lower the interfacial tension between oil and water. The project is organized into three parts, simulation; imbibition at laboratory conditions; imbibition at reservoir conditions.

The potential for chemical flooding of a fractured low permeable chalk reservoir was evaluated using the FRAGOR 1-D dual porosity simulation model and available North Sea PVT and reservoir data. The effects of changing rock wettability, fluid interfacial tension, and matrix block sizes are discussed.

Experiments were performed at laboratory conditions to study the effects of interfacial tension, core length, and wettability on the imbibition of a surfactant solution into an oil saturated chalk material. The wetting phases are synthetic brine and a 1.0 wt% solution of alkyl- propoxy-ethoxy-sulfate dissolved in the brine. The non wetting phases are n-heptane and mixtures of n-heptane and the C_{7+} fraction of Ekofisk stock tank oil. The IFT between the surfactant solution and the oil phase is between 0.004 and 0.02 mN/m. The chalk material has low permeability, 3 mD, and high porosity, 40 %. The imbibition

mechanism is discussed in terms of capillary and gravity forces. The rate of the oil expulsion is discussed in relation to possible Marangoni flow effects. Centrifuge experiments support the finding that it is hard to displace water trapped oil in a tertiary flooding process of a water-wet system even with a very efficient surfactant. Under water-wet and mixed-wet conditions the displacement of oil at low IFT is probably too slow for field applications.

Imbibition studies at reservoir conditions, 130 °C and 4000 psia, using cores from the Tor formation at the Ekofisk field are performed in the presence of a cationic surfactant with a moderate decrease in the IFT, 3 mN/m. The results are in line with observations at laboratory conditions.

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EVALUATION OF THE TECHNICAL AND ECONOMICAL POTENTIAL FOR SURFACTANT FLOODING IN NORTH SEA RESERVOIRS

Stein Rune Jakobsen and Frank Hovland, Geomatic

Abstract

The technical and economical potential for surfactant flooding in four major North Sea reservoirs have been evaluated based on a large number of full field numerical simulations.

Different well patterns were tested for each reservoir to improve the sweep efficiency, and for each well pattern a number of slug volumes were investigated as the economical potential is strongly related to the balance between increased oil production and surfactant consumption.

Further, the influence of interfacial tension, CDC curve, surfactant adsorption and polymer concentration on the technical and economical potential was investigated.

The study shows that the technical potential in all four reservoirs is significant. The increased oil production represents in some cases as much as 7% of OOIP.

However, the economical potential with present chemical costs is marginal. It is found that the surfactant cost preferably should be in the order of less than 10 - 15 NOK/kg.

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EFFICIENCY OF SURFACTANTS

Ingebret Fjelde, Tor Austad, Knut Taugbøl, Kirsti Veggeland and Svante Nilsson, RF - Rogaland Research

Abstract

The intention with this project was to increase the economical potential for chemical flooding by decreasing the chemical costs and reducing the technological risk.

An anionic surfactant is the type of surfactant that will give lowest adsorption to reservoir rock and lowest partitioning into the oil phase. To avoid unfavorable surfactant-polymer inter- action, anionic or very hydrophilic, nonionic polymers have to be used in low tension polymer floods (LTPF). It is possible to design II(-) formulations of high efficiency by using the RF1-surfactant, $C_{12-15}(PO)_4(EO)_2OSO_3Na$. By adding a polymer to these formulations the oil recovery is increased due to higher viscous forces and better mobility control in the reservoir. In reservoirs containing clastic clay minerals, the polymer will also reduces the surfactant adsorption. The estimated cost of the RFl-surfactant is 14 NOK/kg. The RF1-surfactant can only be used at low temperatures, near neutral pH or if the time of residence in the reservoir is short. Mechanisms in LTPF were studied using the RF1-surfactant. The corresponding sulphonates are expected to be efficient and stable at higher temperatures and lower pH. It appears to be difficult to avoid chromatographic separation in dual surfactant formulations containing different types of surfactants. These negative effects may be reduced by using surfactant gradients.

Waterflooding is found to be more efficient than earlier estimated in some high permeability formations in the North Sea, and the economical potential for chemical flooding is therefore reduced for these formations. However, chemical flooding may still have a potential in low-permeability reservoirs and/or in reservoirs where the gravity forces are less important. Cheap surfactant products or low surfactant concentrations able to give moderate interfacial tensions may have a potential for acceleration of vertical surface film drainage.

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PHASE STUDIES OF SURFACTANT-BRINE-OIL SYSTEMS AT RESERVOIR CONDITIONS

Tor Austad, Helge Hodne, Skule Strand and Kirsti Veggeland, RF - Rogaland Research

Abstract

Multiphase PVT-studies are conducted on surfactant-brine-oil systems relevant for oil recovery processes. In the high temperature studies an alkyl-o-xylene sulfonate is used as surfactant, NaCl-solution as brine, and various types of live oil, i. e., crude oil, fraction of crude oil, and model oil. Solubilization parameters for the microemulsion phase are determined in the temperature range of 40-180°C and the pressure range of 200-1000 bar. By increasing the pressure the trend in the phase behavior in all cases is II(+)/III/II(-). In the temperature scan the crude oil system showed a

II(-)/III/II(+) phase behavior by increasing the temperature, while the model oil and the distillation cut of the crude oil without the heavy end fraction showed the opposite phase behavior, II(+)/III/II(-). The difference in the phase properties is discussed in terms of the resin-type compounds acting as cosurfactants, and the dissolution of water into the oil phase at high temperatures.

In the low temperature studies, 70-110°C, the ethoxylated sulfonate termed AS-142 from Berol was used as surfactant in combination with sea water and live crude oil. The effects of pressure, temperature, and GOR on the phase volumes are observed. In general, AS-142 has a preference in forming either a II(-) or a II(+) phase state. The two-phase area is very little affected by changes in pressure. The system moves towards the II(+) state as the temperature is increased. The swelling of the microemulsion phase is sensitive to the amount of dissolved gas, indicating that the interfacial tension between the two phases increases as the GOR decreases.

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CRITERIA FOR LOW VALUES OF REMAINING OIL

SATURATIONS

Ingebret Fjelde, Hildegard Tengberg-Hansen and Svante Nilsson, RF - Rogaland Research

Abstract

Water injection in some North Sea sandstone reservoirs is reported to be more efficient than earlier estimated. Conditions and/or processes taking place in these reservoirs have therefore not been correctly reproduced by laboratory experiments and simulations.

In this study, the effects of pH and asphaltenes on spontaneous imbibition, interfacial tension and oil recovery in vertical waterfloods were studied. Both spontaneous imbibition and remaining oil saturation (ROS) were affected by asphaltenes and pH.

Parameters that will affect ROS in reservoirs and the estimate of ROS are discussed in relation to published work. It was earlier assumed that the reservoirs were water-wet, but it is now well known that several reservoirs are near neutral or mixed-wet. This has affected the design of laboratory experiments and simulations.

It is important to also include gravity effects in the estimate of ROS. Gravity forces can prevent capillary trapping of oil. Vertical surface film drainage may also reduce ROS behind the waterfloods front. This process is expected to be especially important for thick North Sea reservoirs with high effective vertical permeability, mixed wettability and low viscous oil.

Lower residual oil saturation than earlier expected may have increased the potential for IOR-processes used to increase the sweep efficiency.

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PROJECT SUMMARIES

THE MICROBIAL METHOD SUBPROGRAM

TRANSPORT AND GROWTH OF BACTERIA IN OIL RESERVOIRS

John Eirik Paulsen, RF - Rogaland Research

Abstract

Water may be diverted by preferential microbial plugging of high permeable zones. Transport, movement and growth of bacteria in porous matrices have been studied in transparent micro-models and sandpacks. Basically, the technique is to feed the bacteria, at anaerobic conditions, and increase the biomass to reduce the permeability. Observed important factors include: 1) The size and shape, as well as the stickiness of the outer cell membrane; important for the entrainment and deposition of the bacteria/ biomass. 2) The flow rate and the cell concentration must be tuned, otherwise filtration may lead to a filtercake at the inlet (a skin plug), or a plug that does not penetrate deep into the core. The larger the pore radii the less pronounced this effect will be. If the pore diameter is very large, it may be difficult to obtain any plug at all. 3) Active production of biopolymers promote the growth of cell aggregates and adherence to surfaces. Both factors influence the establishment of a plug.

Microbial metabolism entails by products that alter the pH. Large pH fluctuations impede the rate of biomass generation, and the microbial process is thus highly dependant on continuous disposal of such components.

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MICROBIOLOGY AND WATER INJECTION IN NORTH SEA OIL FIELDS

Roald Sørheim, SINTEF - John E. Paulsen, Rogaland Research

Abstract

We have investigated features of marine bacteria to demonstrate their potential for use in microbial enhanced oil recovery (MEOR). The results show that seawater contains a considerable amount of nitrate reducing bacteria. These bacteria have a potential to advantageously be applied in oil recovery if nitrate is added to the injection water and if the water injection causes a reduced temperature in the reservoir. The study indicates that nitrate addition to injection water may reduce the biogenic sulfide production.

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