AZERBAIJAN REPUBLIC MINISTRY OF EDUCATION

KHAZAR UNIVERSITY

School of Architecture, Engineering and Applied Sciences

Major: Petroleum Engineering and Management

Student: Muhammad Hasan Shahid

MS THESIS

D-18

ENHANCING THE OIL RECOVERY BY THE HELP OF MAGNETIZED WATER INJECTION

Supervisor: Professor D. Sn. Arif M. Mamed-zade

Khazar University

23.02.10.

BAKI 2010

XÜLASƏ

Gil minerallarını (faydalı qazıntılarını) özündə saxlayan neft yataqlarının inkişafı bir neçə cətinlikləri özündə saxlayır. Bu səbəbdən, məsaməli zonada maye axınınında gilin bəzi xüsusiyyətləri birinci mərhələdə laboratoriya şərtlərinin öyrənildi:

(1) su yolu ilə maye karbohidrogenlərin yerdəyişmə effektivliyində gilin effekti;

(2)tək fazalı suyu axının sürətinə maqnit sahəsinin təsiri;

(3)gil minerallarının şişmə həcminə maqnit sahəsinin təsiri;

(4)axma qabiliyyətin\ maqnitləndirilən suyun təsiri.

Sonra biz Rusiya Tatariya Neft Yataqlarında Maqnitləşdirilmiş Su Vurulma nəticələrini öyrəndik və biz tapdıq ki, laboratoriya şəraitində öyrənilən nəticələr tədqiqatı əsaslandırdı.

Sahədə və laboratoriya şəraitində məsaməli zonada maye axınında gilin effektini öyrəndikdən sonra Norveç Dəniz Qumdaşı Yatağında laboratoriya nəticələrini əsaslandıran ilkin nəticələri tətbiq etdik və ilk tədqiqat göstərdi ki,25 (iyirmi beş) yataqdan 11 (on bir) yataq Maqnitləşdirilmiş Su Vurulması üçün müvafiqdir;

Balder (Heimdal Lay), Draugen (Rogn Lay), Gulf (Brent Group, Cook Lay, & Statfjord Lay), Gulf (Brent Group, & Lunde Lay), Gyda (Farsund Lay), Heidrun (Tilje Lay), Snorre (L-DEF & L-BC), Statfjord (Brent Group & Statfjord Lay), Ula (Ula Lay), Sleip. -V (Hugin Lay), and Veslef. (Brent, IDS, & Statfjord Lay).

ABSTRACT

The development of oil fields in rock containing clay minerals involves a series of complications. For this reason, some effects of clay on fluid filtration in porous media were studied under laboratory conditions at the first stage:

(1) The effect of clay on the displacement efficiency of fluid hydrocarbons by water;

(2) The effect of magnetic field on the velocity of single phase water filtration;

(3) The effect of the magnetic field on the swelling capacity of clay minerals;

(4) The effect of magnetized water on the displacement efficiency.

Later on we studied the results of Magnetized Water Injection at Tatariya Oil Field of Russia and we found that the results obtained by lab based study are similar with field based results.

After studied the effect of clay on the fluid filtration in porous media at field and lab levels, we applied the lab based results on the Norwegian Offshore Sandstone Reservoirs and the initial study suggest that out of 25 (twenty five) fields 11 (eleven) fields are suitable for Magnetized Water Injection;

Balder (Heimdal Formation), Draugen (Rogn Formation), Gulf (Brent Group, Cook Formation, & Statfjord Formation), Gulf (Brent Group, & Lunde Formation), Gyda (Farsund Formation), Heidrun (Tilje Formation), Snorre (L-DEF & L-BC), Statfjord (Brent Group & Statfjord Formation), Ula (Ula Formation), Sleip. –V (Hugin Formation), and Veslef. (Brent, IDS, & Statfjord Formation).

TABLE OF CONTENTS **Page**

LIST OF FIGURES

LIST OF TABLES

CHAPTER 01

Magnetization

CHAPTER 01

MAGNETIZATION

1. 1 Earth's Magnetic Field

The present work is directed to a process and apparatus to extract residual hydrocarbon oil that is trapped in the formations of underground reservoirs. While North American reservoirs still hold a third of a trillion barrels of hydrocarbon oil, the easier-to-produce oil in North America is almost gone even with current advanced reservoir-enhancement capabilities. Most of what remains are oil which resists extraction. The challenge is to overcome the Earth's natural resistant forces that are immobilizing the hydrocarbon oil and to realign the forces acting on the oil while it is in the earth and thus make it easier to extract from the reservoir.

The Earth's geomagnetic field; its plasma and colloid state; its minerals and rocks; formation waters, residual oil, and reservoir characteristics-all of these mechanical and physical properties act and react to electric and magnetic forces which tend to hold residual oil captive.

The Earth is surrounded by a magnetic field within which it behaves as if it were a magnetized ball with north and south magnetic poles.

Carl Friedrich Gauss published Allegemeine Theorie des Erdmagnetismus in 1838. In his mathematical analysis, Gauss showed that more than 95 percent of the Earth's magnetic field originates within the Earth's interior, and only a small remaining portion comes from outside sources.

The Earth's magnetic field results from electric currents which generate electric charges within the Earth's core. That portion of the Earth's magnetic field produced by outside sources is related to electromagnetic activities in the Earth's upper atmosphere. The primary outside sources produces a flow of electric current in the Earth's electrically conductive interior by a process of electromagnetic induction. Daily geomagnetic variations are attributable to the transient electric currents that are electromagnetically induced within the Earth's interior by the primary magnetic field variations of the outside sources. The Earth's electric and magnetic fields are affected by external factors such as the effect of this induced current. The Earth's magnetic field is gradually changing with time in its intensity as well as in its distribution pattern. These changes affect the characteristics of subsurface minerals, rock and fluids.

There are five mechanical properties of the earth's body that are fundamental to the determination of its behavior-density, pressure, gravitational intensity, incompressibility and rigidity. Density refers to mass per unit volume, which varies within the earth because of variations of composition. Pressure refers to the force per unit area inside a body, and incompressibility indicates the extent to which a material resists pressure. Rigidity indicates the resistance of a material to the stresses that tend to distort it, and gravitational intensity is the force per unit mass arising from a gravitational field.

1.2 Minerals & Rock

When the earth "cooled" from its believed-to-be original state, the ions responded to their electrical attractions and bonded together in the fixed positions of solids. All the elements were present in this original molten matter, but oxygen, silicon, iron, and magnesium made up 90 percent of the total. Sodium, aluminum, potassium and calcium were also present in significant amounts.

One of the first combinations of elements formed was a four sided structure with four oxygen atoms around one silicon atom, the silicon-oxygen tetrahedron; it is the basic unit in 90 percent of the materials of the earth's crust. Electrically conducting clays contains this tetrahedron. Electrically conducting and magnetically susceptible iron is the most abundant element in the earth and the fourth most abundant element in the earth's crust (after oxygen, silicon and aluminum). Most sedimentary rocks contain iron as a cementing or accessory mineral in the form of carbonates, hydrated silicates, oxides, hydroxides and sulfides.

Historically, the first logging measurement, the spontaneous potential, was a measurement of the electrical currents that occur in the wellbore when fluids of different salinities are in contact. Well logs can determine many of the various physical properties of the rocks penetrated by the wellbore. One of the most useful of these properties is electrical resistivity. Electrical resistivity can be defined as the degree to which a substance "resists" or impedes the flow of electrical current. It is a physical [property of the material, independent of size or shape. Low resistivity corresponds to high conductivity; high resistivity corresponds to low conductivity.

Minerals containing iron, manganese and the common magnetic mineral magnetite have large susceptibilities to magnetization and are called ferromagnetic. For these materials, the individual ion particles align themselves spontaneously to produce a magnetization even in the absence of an inducing magnetic field. The application of a magnetic field by an electromagnetic coil causes progressive reorientation of the magnetic domain, including a net magnetization so large that the magnetic susceptibility of the rock formation is dominated by its content of ferromagnetic minerals even though these are present only as minor constitutions. Rocks of higher than normal magnetic susceptibility beneath the earth's surface tend to enhance the earth's magnetic field locally in the same way that an iron core enhances the field of an electromagnet.

Reservoir rocks containing ferromagnetic minerals have acquired a residual magnetization which results from the magnetization of the individual grains. Upon cooling at the earth's surface these minerals' became strongly magnetized in the direction of the surrounding earth's magnetic field.

This magnetization is very stable and subsequent exposure of rocks with this residual magnetization to magnetic field several of magnitude stronger than the magnetizing field cannot appreciably change the original magnetization. Magnetization is also acquired by isothermal, chemical, and viscous residual magnetization. Electrically charged formation fluids will be held in a static state in formation rock having residual magnetization.

1.3 Solids, Liquids & Gases

Formation solids and formation fluids display a wide range of magnetic behavior or magnetic susceptibility. Different susceptibilities respond differently to an external magnetic field.

The chief molecule in many types of clay is composed of a single silica tetrahedron which will cause these clays to act as conductors which will contribute to their conductivity in a water-saturated porous formation. When the clay is hydrated, the absorbed ions of the clay form an ionic conductor.

Non-ionic formation fluids, which include some of the hydrocarbons of the reservoir, composed of molecules that do not dissociate into ions and have negligible conductivities, but they tend to be polarized by a magnetic field. The fluid develops positive3 and negative poles and also a dipole moment, from which the fluid acquires energy. This partial alignment occurs in a field whose frequency is less than the reciprocal of the time it takes the polar molecules to rotate. The static and dynamic processes associated with the motion and pressure distribution induced in magnetically polarized formation fluids when in the presence of an appropriate field gradient is known as ferro-hydrodynamics.

Viscosity of a fluid is a measure of its ability to resist deformation when subjected to stress. Viscosity is concerned with the transfer of momentum, and diffusion is concerned with the transport of molecules in a mixture. Diffusion rate in solids is extremely small, and diffusion rates in liquids are much smaller than those in gases.

Crystals of polar symmetry are little altered by external influences. Certain materials, especially paraffin containing polar molecules, exhibits similar and more controllable effects and are known as electrets. If molten dipolar paraffin is subjected to a strong electric field, it becomes polarized. Since paraffin is a good insulator and is hydrophobic, this relatively weak frozen in polarization will persist and remain unaffected by surface charges. This is one form of electrets, the electrical equivalent of a permanent magnet. The electrets gives a method of maintain a static electric field over long periods. Formation fluids would be unable to move in this static field unless the fluids molecules were attracted by a magnetic force of greater potential, such as results from the present invention.

A static condition exists in the reservoir at the point that the mechanical, physical and the earth's electric and magnetic forces are equal to or greater than the formation pressure, causing the movement of the formation fluids to wellbore to stop. This electrostatic force combines with the physical and mechanical properties of the reservoir to resist the mo0vement of formation fluids. The present work acts to cause flow of fluids to the wellbore to resume.

CHAPTER 02

MAGNETIC APPARATUSES IN OIL AND GAS RECOVERY

CHAPTER 02

MAGNETIC APPARATUSES IN OIL AND GAS RECOVERY

2.1 Innovative Technologies

Magnetic field treatment technology can be used for coping with oil and gas production complication of the following types:

1. Corrosion activity;
2. Asphalt, tar and paraffin sedimentation (APTS);
3. Salt sediments formation in the process of oil and gas recover;
4. Water-oil emulsion formation in the process of oil recovery.

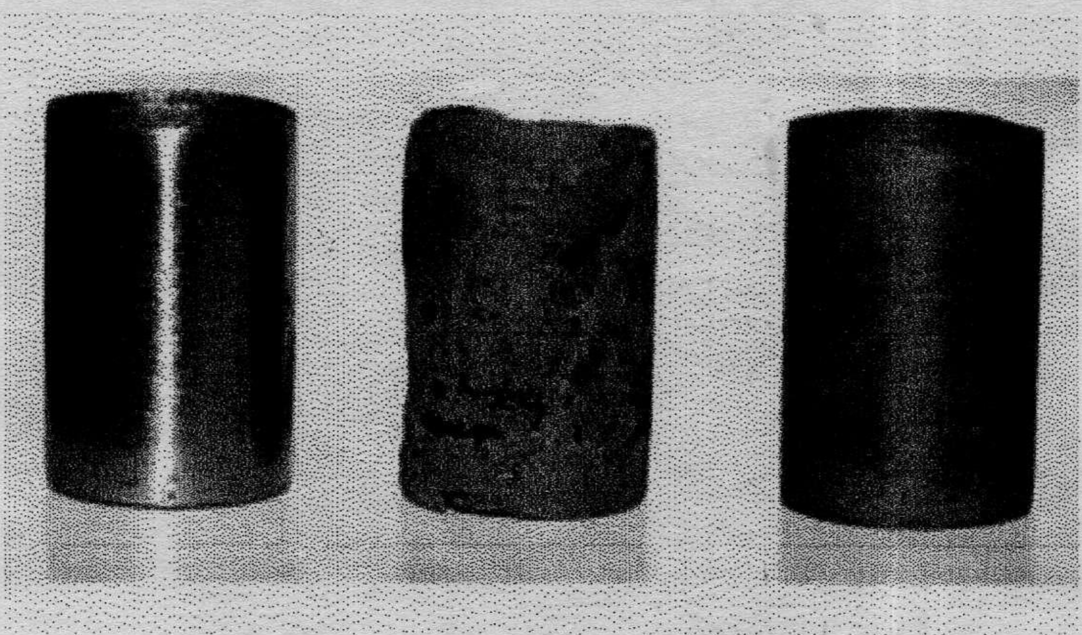
2.2 Corrosion

The decrease of the corrosion activity of produced liquids is caused by the influence on one of their component - over mineralized water. The ions of minerals get polarized and deformed under a magnetic field treatment changes in water molecule aggregation occur. Usually the molecule orientation order get higher and water acquires the so-called ice- Resembling state. The greatest corrosion activity decreasing effect of the technology of a magnetic field treatment is observed in carbonate, sulphate and sulphide types of environment.

But the laboratory research and oil and gas recovery data show that the best way to use this type of treatment is to combine it with inhibitor protection system, which allows reducing the usual dosage of an inhibitor and makes the latter's performance more effective. It should be mention that the best results of the treatment were observed when a permanent magnetic field was used.

Table 01 *Corrosion Activity Reduction Efficiency of a Magnetic Field Treatment for Steel 20*

Sample Point	**Water Composition**	**Corrosion Process Speed without Magnetic Treatment (mm per year)**	**Corrosion Process Speed with Magnetic Treatment (mm per year)**
Martemya-Teterev field (the town of Uray)	Chloride-Hydro-carbonate	0.201	0.086
Sergeyev field (Bashkortistan)	Chloride-sulphide	1.125	0.430
Checkmagush field (Bashkortistan)	Chloride-sulphide	0.830	0.217
Ufa water supply	Oxygen-Hydro-carbonate	0.189	0.105



a) **b)** **c)**

Figure 01 *The appearance of the sample **(a)** – a new one, **(b)** – got from an untreated environment, **(c)** – and got from environment treated with a magnetic field (Sergeev field, Bashkortostan)*

2.3 Asphalt, Tar and Paraffin Sedimentations

The method of a magnetic field treatment may be referred to the group of the most perspective physical methods used for asphalt, tar and paraffin sedimentation prevention. Influencing a flowing liquid a magnetic field destroys the existing in it aggregates, which consist of submicron ferromagnetic micro particles of iron. Usually such aggregates can be found in oil and in according water. Each aggregate consist of hundreds or thousands of micro particles, that's why their destruction leads to a 100-1000 time increase of the concentration of paraffin and salt crystallization and formation of gas bubbles on the surface, of the ferromagnetic particles. As a result of the aggregates' destruction paraffin, crystals precipitate as a fine equally distributed stable suspension. The speed of sediments formation on the surfaces of compressor pumping tubes, pumping equipment is reduced in this case. The sediment formation reduction is proportional to the reduction of the average size of those paraffin crystals, which precipitate into the hard phase together with tars and asphaltens. Some data show that micro bubble formation taking place at crystallization centers after the treatment in certain cases may lead to the gas lift effect.

2.4 Salt Sedimentation

Inorganic salt sediments formation in the process of water saturated oil production at the majority of Russian oil fields. Salt sediments are formed if any of the known well exploitation methods is used, but the most harmful effect is observed when oil is recovered with the help of a rod-type pump (RTP) or an electric submerge working surfaces of deep pumps may cause their early wear, unstable work and breaks of the shaft of the submerge centrifugal pump (ECP), RTP plunger jams, etc.

In this case the period of work without repairs at "salt producing" well, is shortened.
Besides as results of water saturation of the wells production salt sediments are formed on the surface equipment, group and measuring installations, oil gathering collectors and oil preparatory systems. During the process of the magnetic treatment water system changes it's relatively stable, state and inside its volume, but not on the surface, a lot of small crystals formed precipitated from an oversaturated solution, given on picture 3. The crystals, which precipitated from the treated solution, are almost of the same shape and don't differ from each other very much.

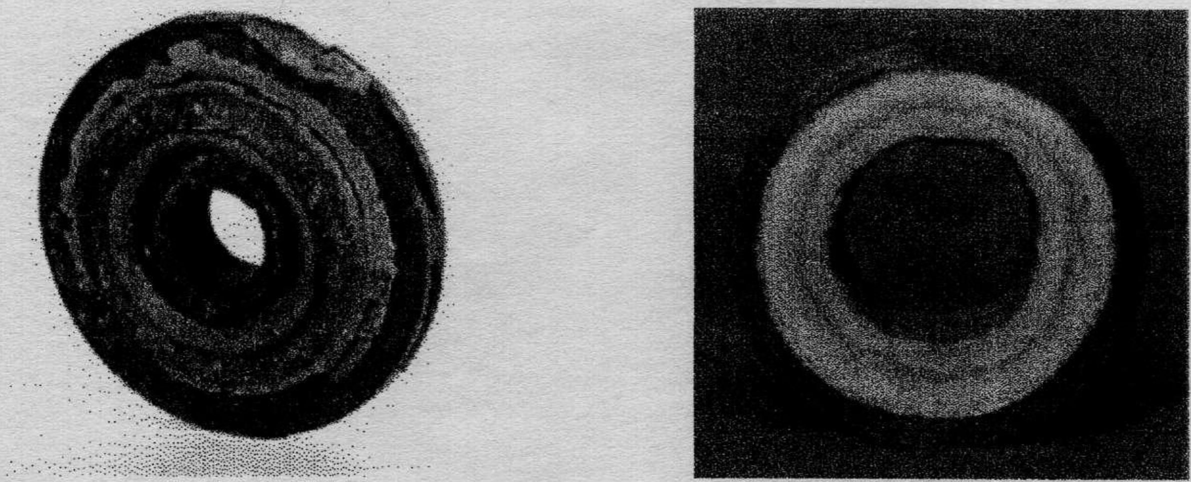
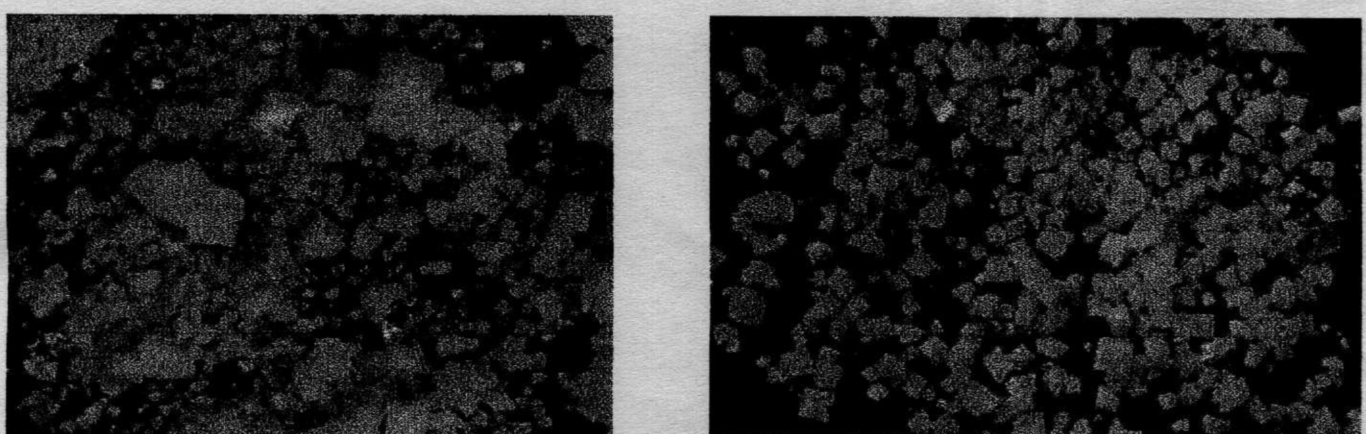


Figure 02 *Salt sediment on the working wheel of an ECP and in pumping and compressor pipes*



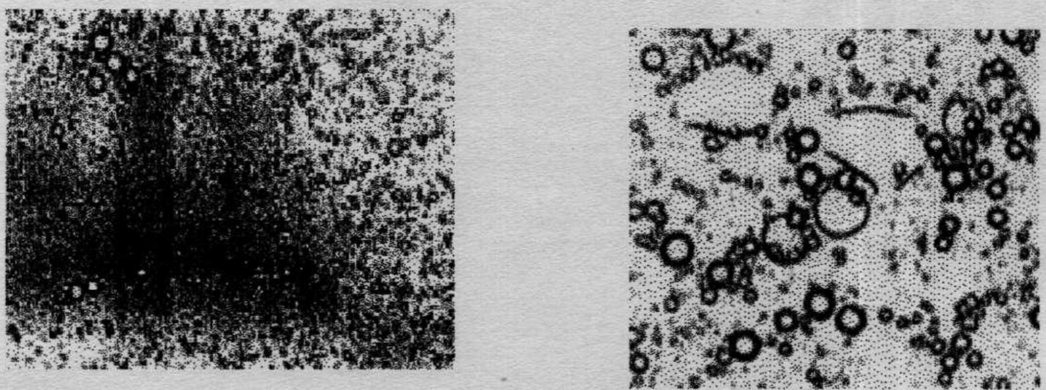
(a) **(b)**

Figure 03 *Sodium chloride crystals precipitated from an untreated solution* ***(a)*** *and from a magnetic field treated solution* ***(b)****.*

2.5 Emulsion Formation

In the process of oil recovery oil gets mixed with water and makes a hard-to-destruct fine emulsion. Emulsion formation is one of the main causes of the high prices for oil transportation and preparation. If the amount of water in oil increases by 1% only, transportation expenses increase by 3-5%. If an alternative magnetic field influences water-oil emulsions, the process of their exfoliation can be accelerated. The best result is observed when the magnetic field has an impulse character (see Fig. 4). Paraffin micro crystals and minimal particles with the surface modified by surface active substances of oil as well as by tars and asphaltens are concentrated at the interphase surface and the finishing stage of this process is oil emulsions' exploitation in a precipitation tank, this is the cause of so-called intermediate layers. The presence of an intermediate layer containing a great amount of paraffin combinations, asphaltens, tars and mechanical impurities make the work of precipitation tanks less effective, reducing actual space, and preventing the separated water from being removed. Practice has shown that only thermo chemical methods when used don't provide deep treatment of intermediate layers. The best results were got only when they were combined with the work of magnetic treatment apparatuses. The method was used in the following way:

1) Determination of the moment when the intermediate layer was formed in a precipitation tank.
2) The in-time removal of the layer and its' treatment with an alternative magnetic field of a low frequency;
3) The feeding of the treated product into the receiver of the apparatuses.



(a) (b)

Figure 04 *Dispersion characteristics of the emulsion before (a) and after (b) A magnetic treatment*

2.6 The Introduction of Magnetic Treatment Apparatuses into Practice

Recently "BashNIPIneft" and USPTU have worked a set of apparatuses for coping different complications in oil and gas now used at different enterprises. The well equipment UMZh-73, using permanent magnets eliminate paraffin sediments, salt sediments at "Bashneft", "Lukoil", and "Belkamneft and Orenburggasprom" wells. The work without repair period was 1, 5-2 times increased. Permanent magnets apparatuses of the UMZh type with the diameter of 100-325 mm are used to reduce the corrosion activity in the reservoir pressure maintained system in Western Siberia and Udmurtia. The amount of the inhibitors used was decreased by 30-50%. Low frequency and impulse electromagnet apparatuses of the UMP type with diameter of 100-520 mm were introduced to combat with emulsions formation at TPE Kogalymneftegas", OSC "Bashneft", SE "Belkamneft". The Engineering Company "Incomp-neft" produces such magnet apparatuses.

Magnetic treatment devices working with permanent or electromagnets should be used in the sphere of oil recovery for coping with complications caused by emulsion formation, salt precipitation and asphalt and paraffin precipitation.

CHAPTER 03

EXPERIMENT

CHAPTER 03

EXPERIMENT

3.1 Modeling Condition

Modeling conditions were chosen accordingly to the similarity criterion (Efors, 1963). From the literature it was found that clay of the montmorillonite (clay mineral mostly used as an additive to mud & it's a Hydrous Aluminum Silicate, capable to react with Magnesium and Calcium) groups have the most significant effect on the fluid filtration characteristics. The actual chemical composition of montmorillonite is $Al_4 Mg (Si_8 O_{20})_4 . nH_2O$ (the water separates the layers of the montmorillonite lattice structure). In this condition, the porous medium models contained various amounts by weight of montmorillonite clay added to quartz sand. The sand is pure and contains no feldspar or other minerals. Characteristics of the porous media use are tabulated below:

Table 02 *Type of Porous Medium*

Type of Porous Medium	Porosity (%)	Permeability (darcy)	Particle size (mm)
Pure Quartz Sand	26	0.2 – 0.4	160 – 200
70% Quartz Sand + 30% clay	21	0.15 – 0.25	160 – 200
50% Quartz Sand + 50% carbonate (limestone: 95-100% calcite, 5-0% dolomite)	23	0.25 – 0.4	160 – 200

The water used in these experiments is clear and without any mechanical impurities. There are no impurities of colloidal mineral particles or of micro plankton type and the salt contents were up to 200 -500 mg/l.

Transformer oil was used as the oil modeling fluid. This is a hydrocarbon fluid which is obtained by atmospheric vacuum oil distillation at up 673 K where we get the oil fraction at 573-673 K and it has the following physic-chemical properties: density-0.88 grams/cm^3; viscosity-9mm^2/c under 323 K; the flash point is not less than 408; the solidification not more than-326 K; the dielectric loss tangent 0.5% at 363 K.

The experimental investigation was conducted in the equipment illustrated in Figure 05.

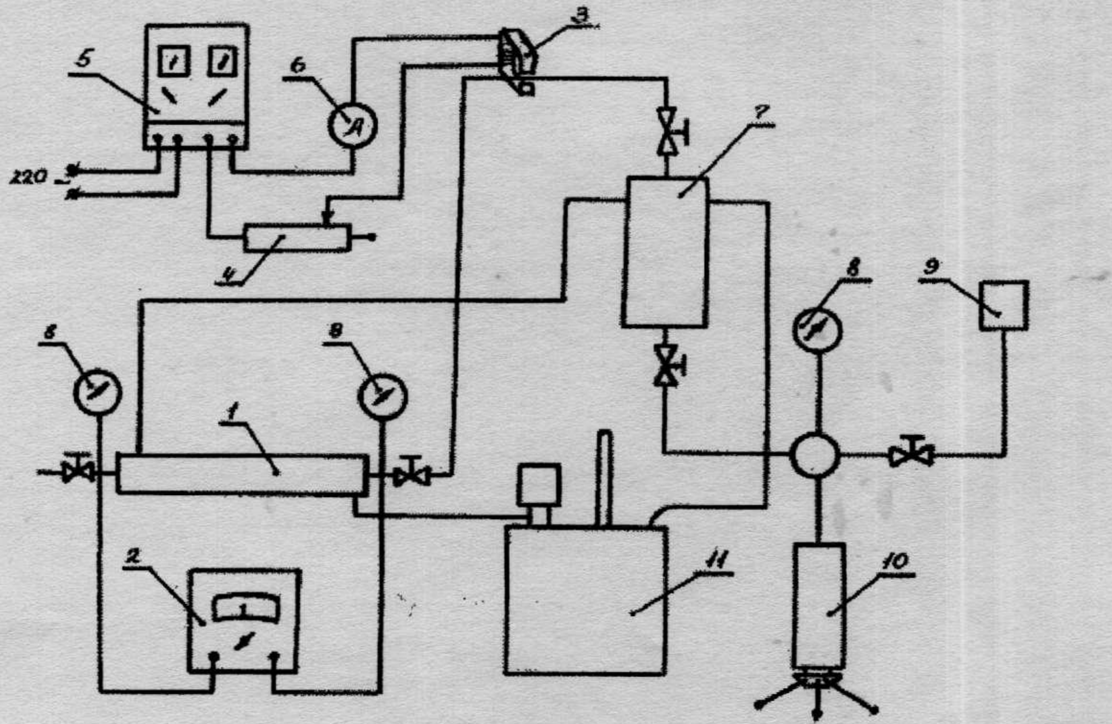


Figure 05 *Experimental investigations. 1- high pressure, 2-potentiometer with high input resistance, 3-electromagnet, 4-rheostat, 5-rectifier of UCA-4a type, 6-ampere voltmeter, 7-high pressure bomb PUT-type, 8-sample manometers, 9-tank for pressurizing the fluid, 10-measuring press, 11-thermostat.*

3.2 Effect of clay on the efficiency of displacement of hydrocarbon fluids by water

3.2.1 Experiment

The experiments were conducted in the following sequence of steps: the porous medium was tamped into the high-pressure column 1 and was saturated with transform oil under vacuum. The porosity, permeability and other characteristics of the porous medium were defined. Water was pumped into the PUT-7 bomb to displace oil from the medium.

3.2.2 Result and Discussions

The results of the investigations are shown graphically in Figure 6. The graphic analysis shows that the presence of clay decreases the displacement efficiency ξ by 33% (curve 1and 4). In order to regulate the oil-displacement efficiency, we decided to subject the transform-oil-porous-medium system to a magnetic field. Experiments were made in the same sequence of steps, but the water was subjected to a magnetic field throughout process. Figure 6 (curves 2 and 3) shows that the oil displacement efficiency in the clay containing porous medium by water magnetized at 52,000 A/m intensity increased by 38% as compared with displacement by normal water.

With the aim of increasing the efficiency of magnetically treated water in displacing hydrocarbons in a porous medium, the influence of magnetized solutions of $CuSo_4$ and $FeCl_3$ upon the displacement coefficient ξ was studied. It has been found that the ξ values shown by magnetized water (with 200-500 mg/l salt) and by magnetized solutions of $CuSo_4$ and $FeCl_3$ of different concentrations is approximately the same. It has only been observed that the filtration of $CuSo_4$ and $FeCl_3$ solutions in the porous medium becomes slower as the results of magnetization. Hence, we conclude that a saline water composition acts comparatively less on the displacement coefficient than does the magnetic treatment of water.

At the porous medium contains quartz sand in great quantities, it was decided to study the effect of magnetized water on the oil displacement efficiency in quartz sand alone. The result of the experiments given in Figure 14 shows that treatment by magnetized water does not affect the oil displacement efficiency in this case.

3.3 Effect of a magnetic field on the velocity of single phase water filtration

3.3.1 Experiment

Experiments were carried out as follows: the porous medium was tamped into the high pressure column (1); the parameters of the porous medium, such as porosity and permeability were defined. Then, the porous medium (under vacuum) was saturated with water and the filtration velocity of water found. The magnetic field was switched on and the velocity of the magnetized water filtration was found. Comparing the two velocities, we determined the effect of magnetic field on water filtration.

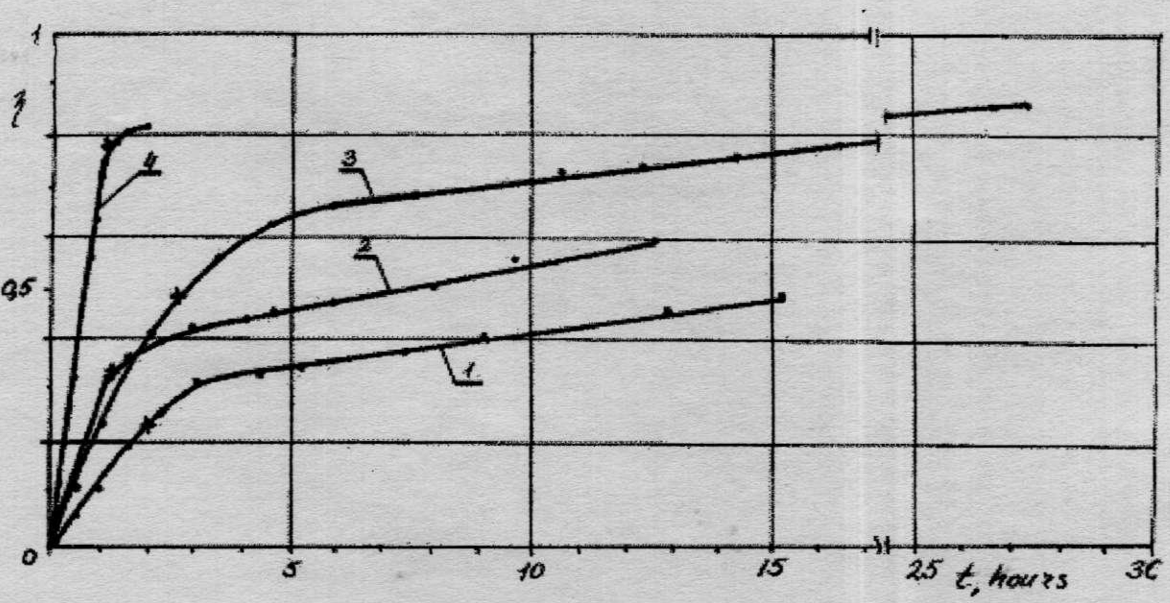


Figure 06 *Displacement efficiency. 1-in clay containing porous medium with water, 2-with magnetized water of 64,000 A/m, 3-in clay containing porous medium with magnetized water of 52,000 A/m, 4-in pure quartz sand containing water.*

3.3.2 Result and Discussions

The results of the experiment with the porous medium (quartz sand + 5% clay) are presented in Figure 07. The average water velocity without magnetic action was 45.4 cm^3/ h. This value was stable for two days. In the case when a magnetic field of 52,000 A/m was applied, the velocity gradually increased within the first three hours by 5-7 %. Later on, the filtration velocity reached 50 cm^3/h and remained stable till the magnetic field was switched on. After the magnetic field has been switched off, the velocity dropped to 47.2 cm^3/ h within 1.5 hours and only a complete change of water in the porous reduced it to 45.6 cm^3/ h i.e., close to the original value.

It is important to note that no influence of the magnetic field on the water filtration velocity in the porous medium containing quartz sand was observed. It is known that in the process of water filtration through clay minerals of montmorillonite structure, a sharp slowdown of the filtration velocity and sometimes even no motion at all, is observed as a result of intensive swelling (Zlachevskaia, 1969). To answer the question of whether the treatment of water by a magnetic field affects the swelling characteristics of clay, the following series of experiments was carried out.

was carried out. In this process of displacement, the pipe connecting the PUT bomb (7) and the bed model (1) was passed through an electromagnetic core enabling a steady transverse field to affect it; thereby magnetization took place. The magnetic current in the core was controlled by varying the current intensity by means of the rheostat (4). To obtain a steady magnetic field, a direct current from the rectifier (5) was passed through the coil of the electromagnet (3). The magnetic field intensity in the core was set equal to 52,000 A/m. displacement of oil in this case was carried out as in the first experiments, i.e., till clean water appeared. Under the same conditions (t=313 K; P=16 MPa), the pressure recovery curves after 1, 5, 9, and 13 days of the experiment were as plotted in Figure 10.

To study the process of magnetic field dissipation in the third series of experiments, a diamagnetic brass model body of the porous medium (a high pressure column) was used. The model was filled with a porous medium containing 85% of quartz sand and 15% of montmorillonite clay. For a porous medium containing 30% of montmorillonite clay and 70% of quartz sand, a higher pressure differential is necessary, but because of the low body strength of the column, it was impossible to apply such a pressure, so the porous medium with only 15% clay component was used.

The experiments were made according to the above mentioned methods and the porous medium, under the same conditions (t=313 K; H=52,000 A/m), was saturated with transformer oil which was then displaced by magnetized water. After the process of displacement was terminated, the pressure recovery curves in the model were plotted at one day intervals and for this purpose a 5.7 MPa pressure was applied to the porous medium.

3.4.2 Result and Discussions

The results of the first experiments, with pressure recovery curves after 1, 4, 7 and 10 days of the experiment, are given in Figure 8. The dependence of the pressure recovery time on the time elapsed since the beginning of the experiment, for pressure levels of 2 and 12 MPa, is plotted in Figure 9. Analysis of this relationship shows that this time increases with increase of the time interval, which results in deterioration of the filtration characteristics of the porous medium. Swelling of the clay is responsible for this. The velocity increase falls gradually and this points to the limited interval after which recovery time does not change. This interval shows the end of the swelling process in the clay.

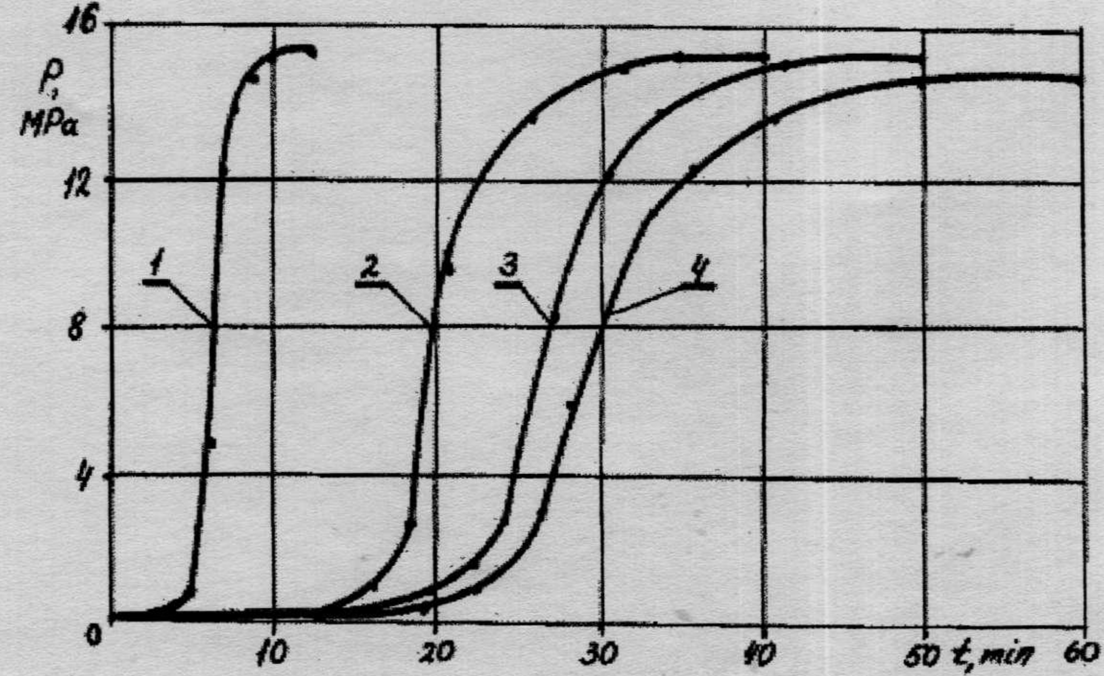


Figure 08 *Pressure recovery curves in clay porous medium with water 1-on the first day, 2-after fourth days, 3-after seven days, and 4-after ten days.*

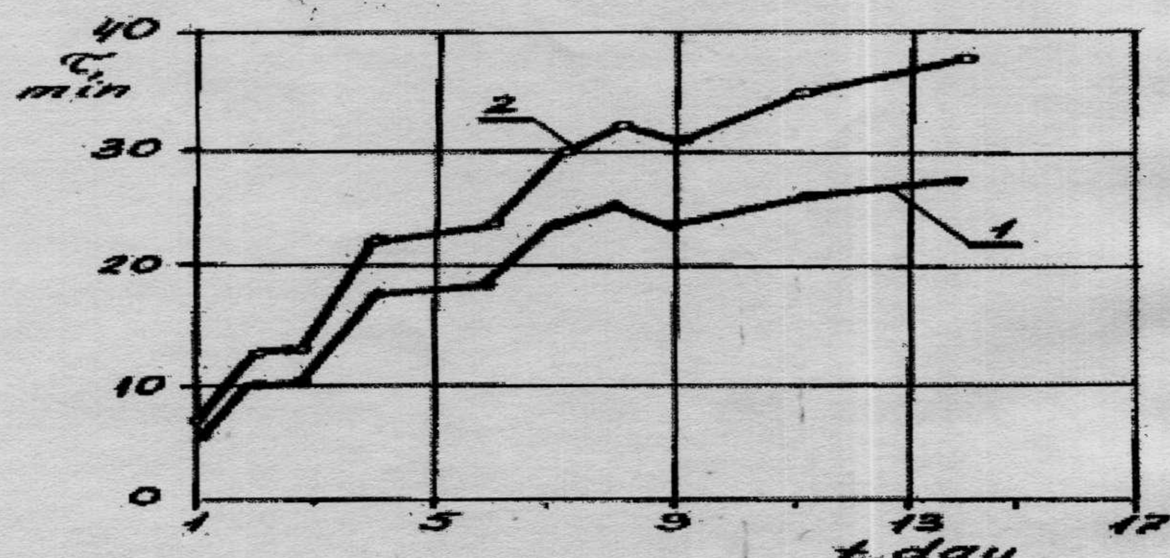


Figure 09 *Dependence of the pressure recovery time on the time elapsed since the beginning of the experiment for pressure levels of 2 MPa (curve 1) and 12 MPa (curve 2)*

The result of the second series experiments are presented in Figure 10 and 11. Dependence of the pressure recovery time on the time elapsed since the beginning of the experiment, for pressure levels of 2 and 12 MPa, are plotted in Figure 11. Similarly, the same recovery time increase as a result of clay swelling was observed within the first six days as in the model with water. After this interval, the recovery time decreased due to removal of clay swelling components and improvement of the filtration characteristics of porous medium by magnetized water. This improvement reached its climax in 12-13 days and no significant changes were noted during a long time period (47 days). Such a long term improvement can be explained by the fact that the model body is a screen preventing the magnetic field from dissipating and, as a result, the porous medium residual oil water system was always affected by the magnetic field.

The results of the third series experiments after 1, 3, 10 and 15 days are given in Figure 12 in the form of pressure recovery curves. The recovery times at the 1 and 5 MPa pressure levels were recorded. The pressure recovery time-time interval relation is presented in Figure 13.

Analyzing these relationships, we conclude that by removing the magnetic effect on the porous medium we get pressure recovery time curves for the first 10 days that are similar to those in the case of displacement with magnetized water, but from the 10th day onward, the pressure recovery time increases as in the case of displacement with non-magnetized water. This means that full dissipation of the magnetic field happened 10 days after removing the magnetic effect and the consequence was that the usual water action resulted in clay swelling.

3.5 Effect of a Magnetized Water on the Efficiency of Displacement

At present there is no theoretical explanation for the effects observed in the case of magnetic treatment water, so these steps of investigation allow us only to explain the result qualitatively. The effect of magnetic field on the capillary saturation with hydrocarbon fluids for (Heeg and Gadziew, 1986) was studied. As a result we obtained that the treatment of fluids by steady transverse magnetic fields of 52,000 A/m intensity increases the capillary saturation in clay containing porous medium. A characteristic of our experiments is that the effect of the magnetic field on filtration is observed of the model contains clay. This change of capillary saturation with hydrocarbon fluids in the case of magnetic treatment was not observed in the sand model.

However, we can only explain this efficiency of displacement increase in the case of magnetic treatment of water by the influence of the capillary effect and the swelling of the clay, because when transformer oil is displaced from the carbonate porous medium, the efficiency increases only due to magnetized water (Figure 18). It is known that a carbonate porous medium does not possess the property of swelling, thus the mechanism of the effect of magnetized water on the efficiency of displacement is not known.

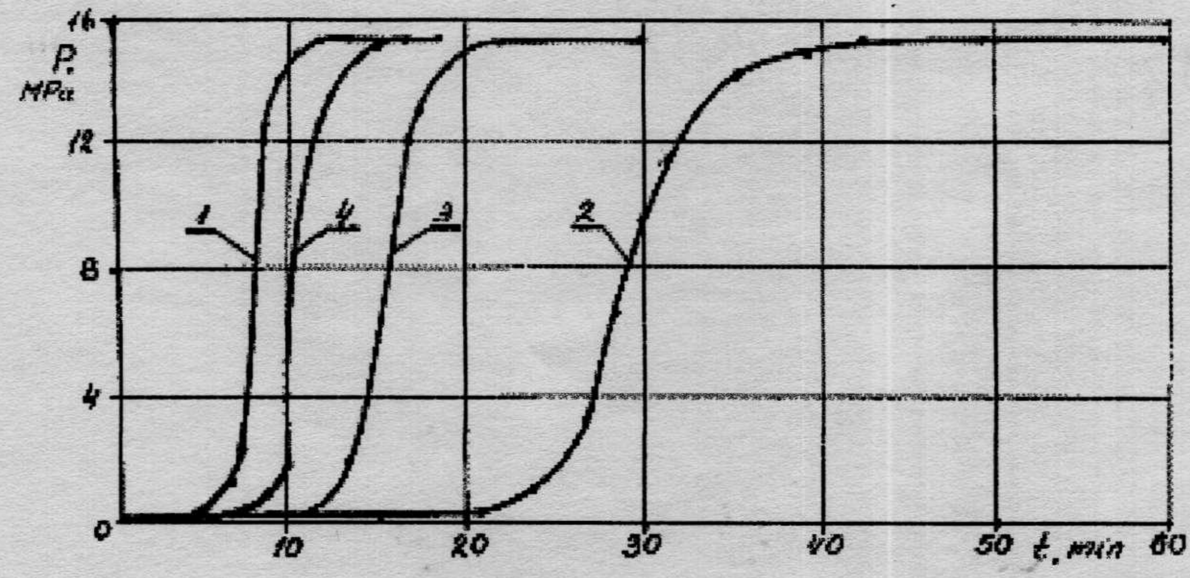


Figure 10 *Dependence Pressure recovery curves in clay porous medium with magnetized water 52,000 A/m. 1-on the first day, 2-after five days, 3-after nine days, and 4-after thirteen days.*

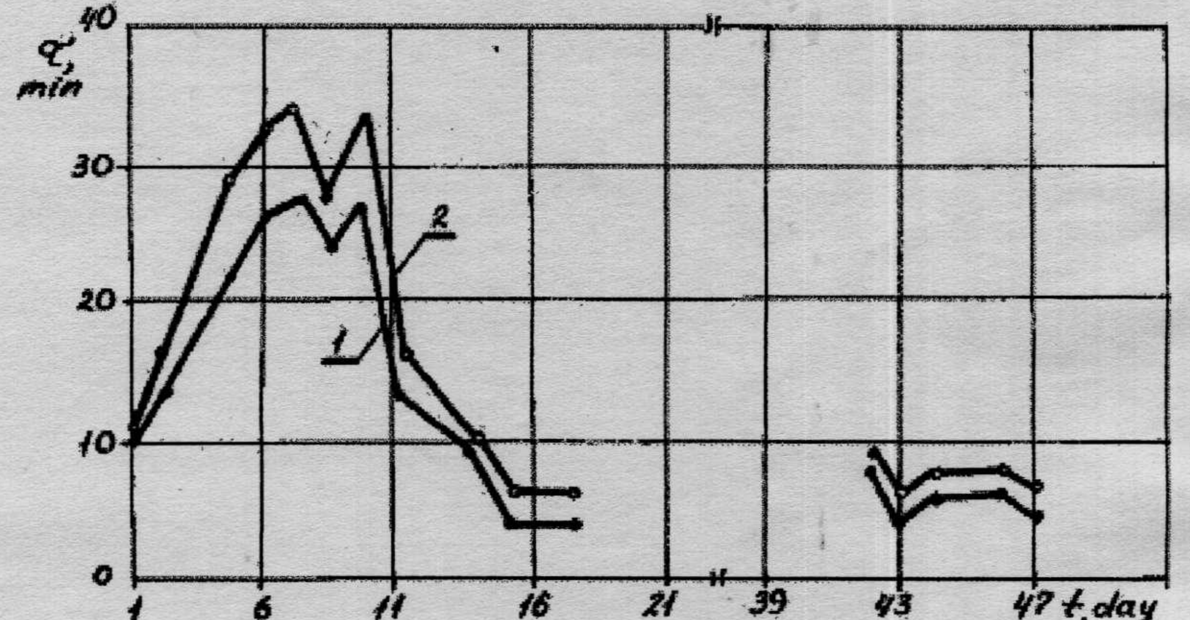


Figure 11 *Pressure recovery time with magnetized water (52,000 A/m). 1-2 MPa, 2-12 MPa pressure*

8351661

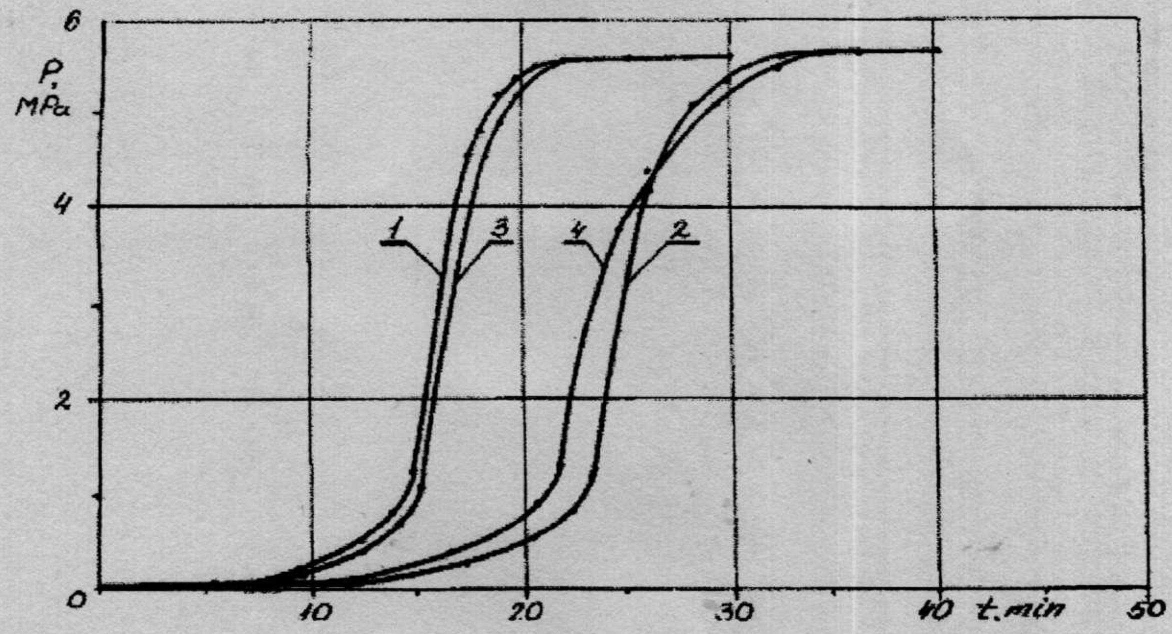


Figure 12 *Pressure recoveries curves. 1-on the first day, 2-after three days, 3-after ten days, and 4-after fifteen days.*

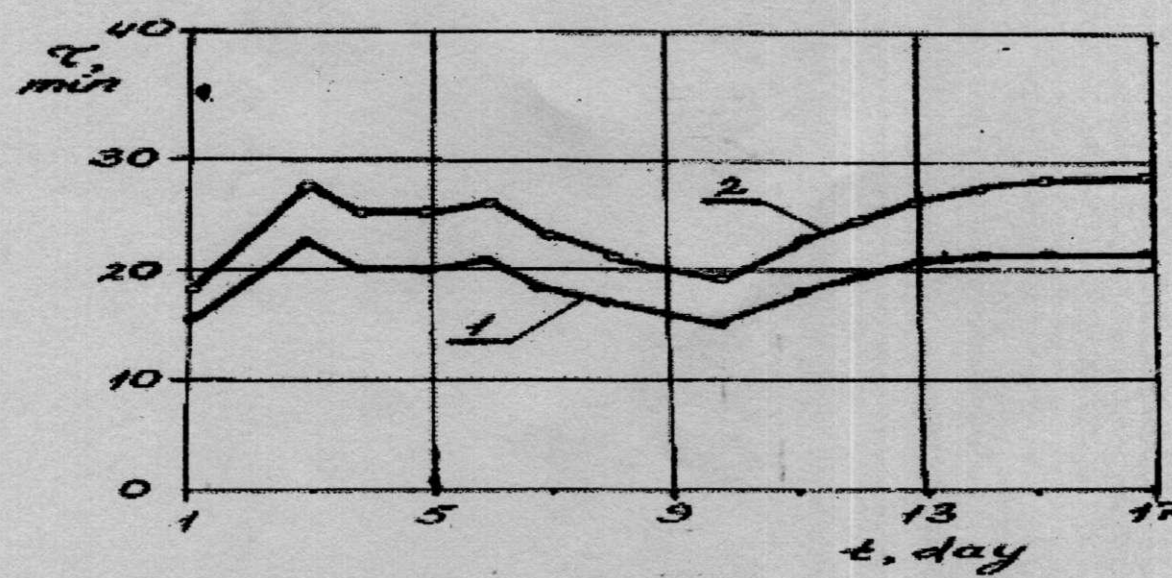


Figure 13 *Pressure recovery time in a high pressure column 1-5 MPa, 2-7 MPa pressure.*

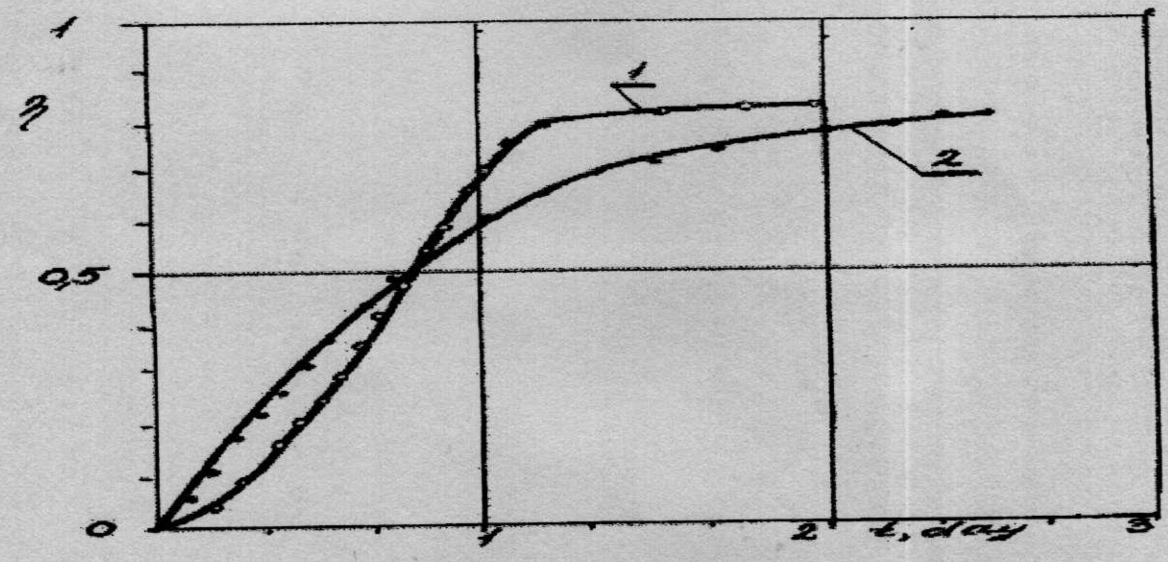


Figure 14 *Displacement of transformer oil in the pure quartz sand. 1-water; 2-magnetized water (52,000 A/m).*

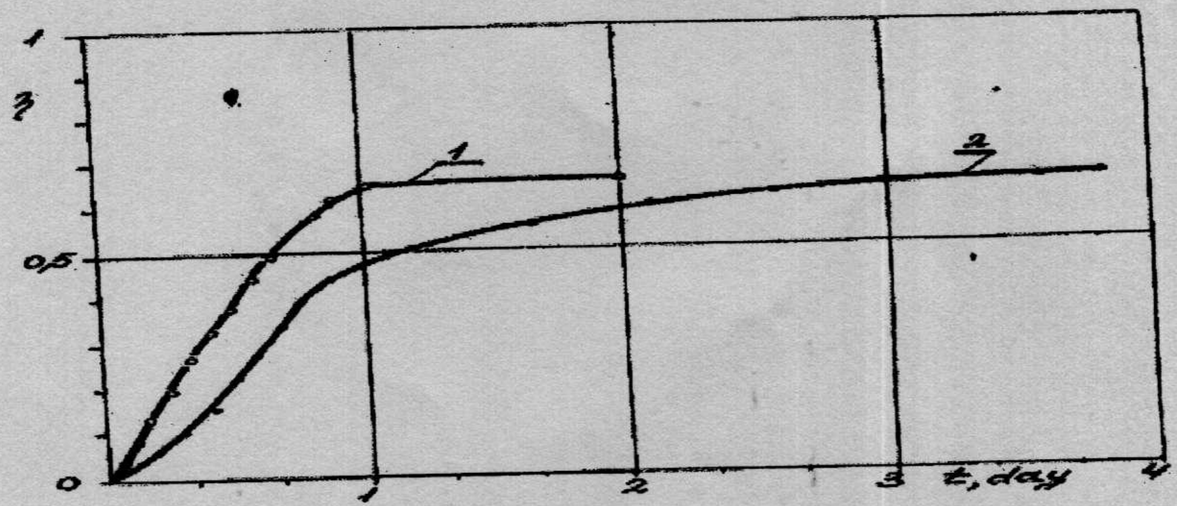


Figure 15 *Displacement of transformer oil in calcined clay. 1-water; 2-magnetized water (52,000 A/m).*

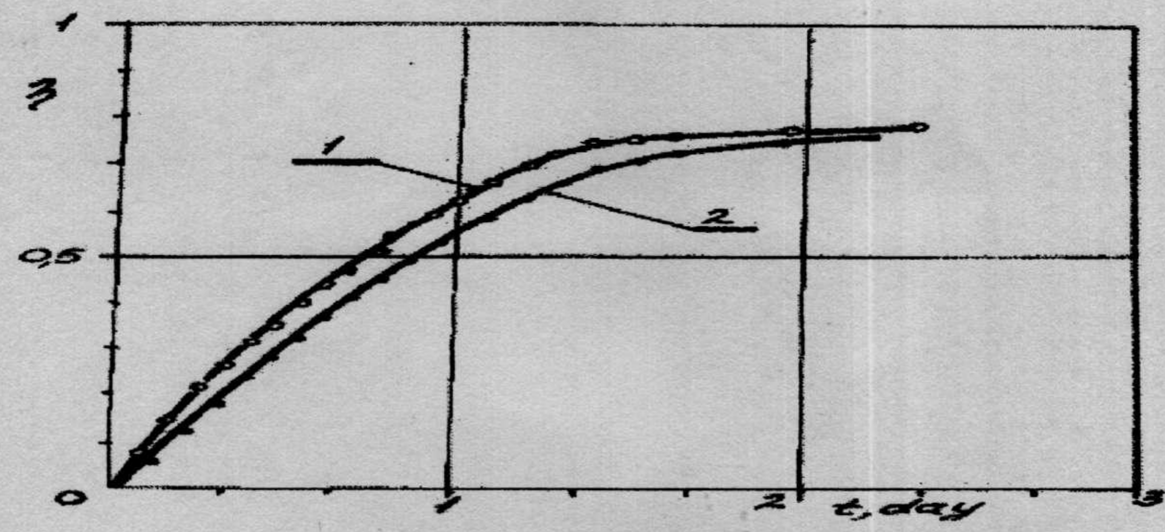


Figure 16 *Displacement of transformer oil in the clay containing porous medium treated with an aqueous solution of HCL. 1-water; 2-magnetized water (52,000 A/m).*

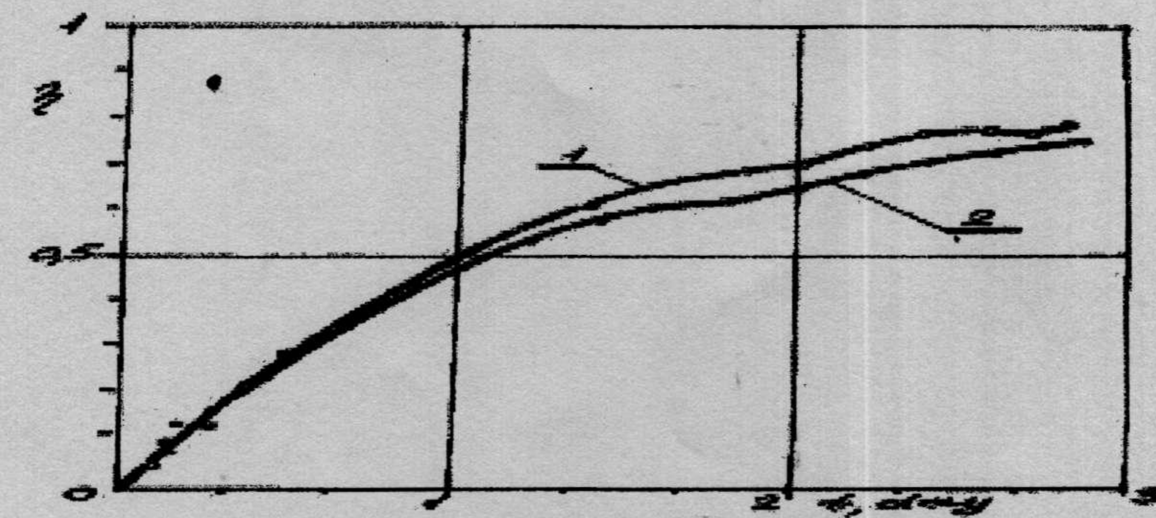


Figure 17 *Displacement of transformer oil in the carbonate porous medium treated with an aqueous solution of HCL. 1-water; 2-magnetized water (52,000 A/m).*

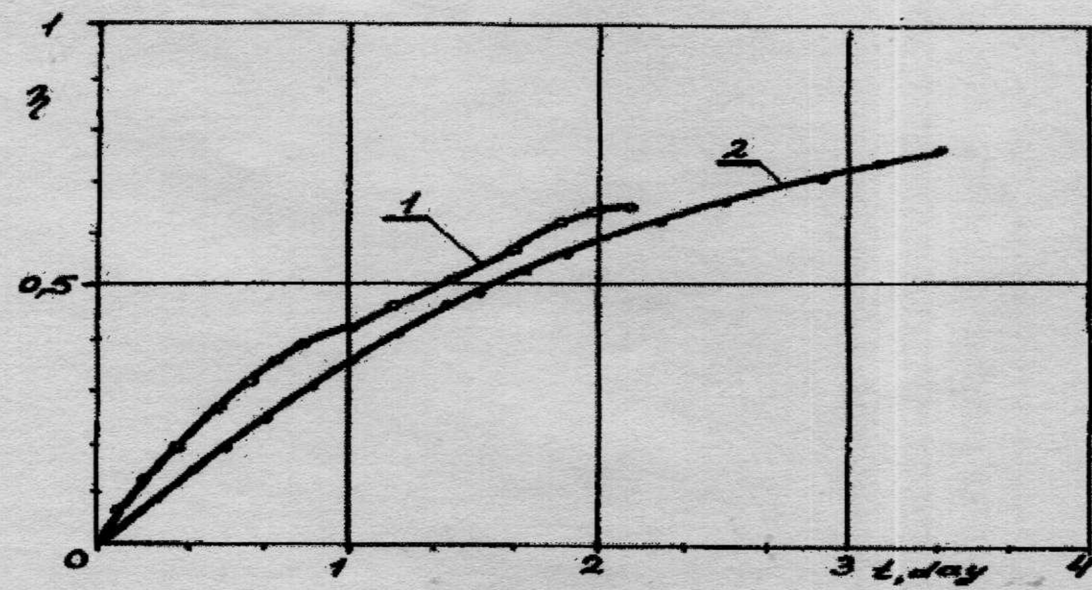


Figure 18 *Displacement of transformer oil in carbonated porous medium. 1-water; 2-magnetized water (52,000 A/m).*

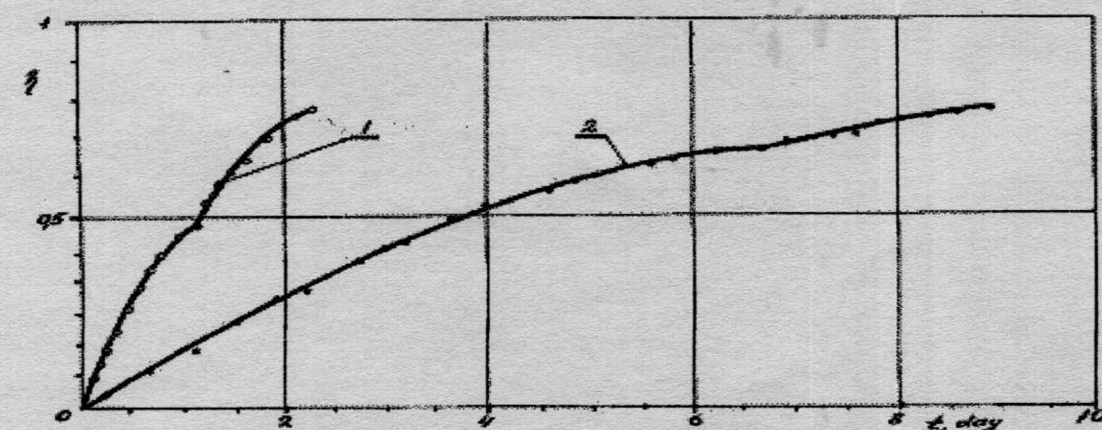


Figure 19 *Displacement of transformer oil in carbonated porous medium calcined to T = 1400 K. 1-water; 2-magnetized water (52,000 A/m).*

3.5.1 Experiment

To examine the possible effect of magnetized water on the efficiency of displacement the investigations in the laboratory were conducted in four steps.

At the first step the displacements of transformer oil from quartz sand both by water (Figure 14, curve 1) and water treated with a transverse magnetic field of 52,000 A/m (Figure 14, curve 2) was carried out.

At the second step the question of the effect of clay swelling on the efficiency changing ξ was studied. The drying theory elaborated by Lykov (1950) shows that clay in the calcining process loses its swelling property. For this reason experiments on the displacement of transformer oil from a porous medium containing 70% of quartz sand and 30% heated clay a t temperature 1300 K were made.

At the third step the effect of the ferromagnetic film of the porous medium on the displacement efficiency was studied. It is supposed that the ferromagnetic film on the clay surface containing particles holds up the hydrocarbon fluids which decrease the efficiency ξ in the process of water displacement. Magnetic treatment of water results in both a compensation of the magnetic field of ferromagnetic film and an increase of the efficiencyη. To verify this hypothesis, it was proposed to change the ferromagnetic film properties into non-magnetic and to determine η after and before the change. Grigorov (1972) showed that it is possible to change the electro-surface properties of α Fe_2O_3 by HCl treatment of the surface while not affecting the volume properties of the substance.

Thus, HCl was chosen for the clay treatment; as a result of the interaction of goethite with an aqueous solution of HCl, we obtain ferrous chloride which does not possess the magnetic properties of substance. The reaction goes as follow:

$$FeOOH + 3HCl \longrightarrow FeCl_3 + 2H_2O$$

Displacement of transformer oil from the clay containing porous medium treated by an aqueous solution of HCl was carried out with both non-magnetized water (Figure 16, curve 1) and with that magnetized by a steady transverse magnetic field of 52,000 A/m.

In the fourth step, which was to some extent a control, oil displacement was carried out from the carbonate porous medium. In this case, the carbonate porous medium contained 50% by weight of carbonates and of quartz sand. Carbonates calcined at a temperature of 1300 K or treated by HCl solution were also used.

3.5.2 Result and Discussions

The result of the first step in the displacement of oil in the quartz sand both by normal water (Figure 14, curve 1) and water treated with a transverse magnetic field of 52,000 A/m (Figure 14, curve 2) are presented.

These investigations have not exposed any effect of magnetized water on the displacement efficiency from the quartz sand. Comparison of ξ values by water from clay (Figure 6, curve 1) and quartz sand (Figure 6, curve 4) shows a decrease of efficiency ξ of 33% in the clay containing porous medium. In the process of filtration intensive swelling was observed. Laboratory investigation presented in paragraph 3 show that a decrease of ξ in clay takes place because of clay swelling and that control of the latter is possible by use of magnetized water.

The results of the second step of the investigations are given in Figure 15. Comparing the values of the displacement efficiency ξ both for clay containing porous medium and for heated clay, we find: (1) as a result of calcining ξ increases by 16% as compared with the process of displacement from clay (compare Figure 15 and Figure 6, curve 1); (2) magnetic treatment of water does not influence the efficiency ξ for the porous medium, containing calcined clay and quartz sand (compare curves 1 and 2, Figure 15).

Hence, it follows that control of clay swelling is not the only factor that increases ξ in the process of oil displacement in the clay containing porous medium by magnetized water.

This conclusion forced us to continue our investigations in order to find out the reason for the efficiency increase as a result of water treatment by a steady, transverse magnetic field of 52,000 A/m. It is known (Terzaghi and Peck, 1948) that increasing the temperature of ferromagnetic materials beyond the Curie points, which are specific for each material, a loss of magnetic properties takes place. This suggests that in the process of oil displacement in the clay containing porous medium by magnetized water, the clay is affected by a number of factors, such as surface change of swelling, magnetic and other physico-chemical properties.

Literature analysis shows that on the surface of clay particles there are minute particles of iron containing compounds that have magnetic properties (Osipov, 1978). The magnetic properties of iron containing compounds that occur in porous media of sedimentary rocks are given in Dortman (1976). Attention was paid to the fact that goethite (α FeOOH) has a coercive force H_c (that is the magnetic field value necessary for full demagnetization of ferromagnets) equal to 56,000 A/m. it should be mentioned that the maximum increase of efficiency ξ was observed in the process of displacement of transformer oil in clay by water magnetized in a steady transverse field of 52,000 A/m.

The results of the third step of investigations are given in the form of curves in Figure 16. The result we obtained in these conditions is a high displacement efficiency ξ similar to that for quartz sand (Figure 14, curves 1 and 2) or clay by water magnetized by a magnetic field of 52,000 A/m (Figure 6, curve 3).

In such conditions ξ does not depend on magnetic field treatment and is about 80% of the level of ξ for sand.

These factors corroborated that hypothesis about the presence of ferromagnetic materials, mainly goethite, on the surface of the porous medium and compensation of their magnetic field in the case of displacement by magnetized water. To prove the presence of ferrous chloride, the porous medium was washed in an aqueous solution of hydrochloric acid and sample analyses by photo-calorimetric titration (Babko and Pjatnicki, 1962) were made at the "Analytical chemistry" chair of Azerbaijan Institute of Oil and Chemistry. Three porous media of equal weight were taken; these were quartz sand, carbonate and clay and they were washed separately in equal quantities of aqueous solution of HCl. The quantity of ferric ions in clay was four times and in carbonates twice as great as in quartz sand.

The results of the fourth step of the investigations are given in Figures 17, 18, and 19. Comparing the displacement efficiency in the carbonate porous medium both by normal water (Figure 18, curve 1) and magnetized (Figure 18, curve 2), we found that due to magnetic treatment of water, ξ increases by 12.5% in the case of displacement by water (Figure 17, curve 1) and magnetized water (Figure 17, curve 2), in the porous media treated by HCl, the change of ξ is only 3.4% which is within the admissible error of the experimental installation. The characteristics feature of this case is that ξ is high and equals about 80%, as with quartz sand (Figure 14, curves 1 and 2), and is not affected by magnetized water. Carbonate calcining increased the displacement efficiency by 80%, as in the case of quartz sand (Figure 19, curves 1 and 2) and is practically not affected by magnetized water.

We can say that in the case of water treatment by a steady transverse magnetic field of 52,000 A/m, we have compensation of magnetic field of 52,000 A/m; we have compensation of the magnetic field of the ferromagnetic film, represented mainly by goethite, on the surface of the solid phase of the porous medium. This results in a better washing out of hydrocarbon fluids, first from clay containing porous media and secondly from carbonates but washing out from quartz sand is practically unaffected.

As a consequence of the above results, the chair of "Oilfield development and exploration" of the Azerbaijan Institute of Oil and Chemistry has elaborated this technology and constructed a magnetic device that makes intensive oil production possible by improving the filtration characteristics both of clay and carbonate oil reservoirs.

CHAPTER 04

CASE STUDY

CHAPTER 04

CASE STUDY

4.1 Tatariya Oil Field

In this section we are going to study the past results of the magnetize water treatment in the wells of the Tatariya oil field of Russia. This research has two steps:

1. Magnetize field influence on intake capacity of the injection wells.

2. Magnetize field influence on rate of the production wells.

First of all, we will study how magnetize field influences the intake capacity of well.

For this purpose, they choose the injection well #3241 in Tatariya (Russia) with multiple layers; property of the existing texture changes from the upper part towards the bottom including the formation: A) clay siltstone; B) sand siltstone; C) sand with low permeability and D) sand with good permeability (this result is shown in column 1 table 03).

Table 03 *Research Results of Well # 3241 (Tatariya Oil Field)*

1	2		3		4		5		6
Formation	Check date 7.04.77	Magnet Installation	Check date 11.04	Magnet Installation	Check date 12.09	Take off magnet	Check date 17.10	Magnet Installation	Check date 12.05.78
"A"	0		0		100%		15%		33%
"B"	0		0		0		0		67%
"C"	0		53%		0		31%		0
"D"	100%		47%		0		54%		0

Before application of the magnetize water on well #3241, they checked formation by the method of dimension profile intake capacity of well and found that all injection water intake sand layer, water rate is 90 m^3/ day (look column 2, table 03).

An oil man wants to increase this rate by fracturing method but it had no effect. After this oil man used acidizing well intervention and it again did not have an effect under conditions of well before and after processing intake 90 m^3/ day water.

To resolve the problem - magnetized field was used to increase water injection and injection magnetize water in well was used at the beginning. After five months rate injection magnetize water increased up to 120 m^3/ day. They wanted to study, which layer intakes magnetize water; for this purpose they checked formation again and found that layer (a) intake 120 m^3/ day (look column 4 table 03).

It is very a crucial result, because in the world practice usually a layer with clay mineral cannot intake water. Usually for activating the layer with clay mineral and increasing the intake capacity of the wells we usually use alkali or different chemical methods; but they are expensive and must shell decrease filtration property of the porous media, must shell increase chemical corrosion well equipments. All of these are disadvantageous and create some kinds of obstacles and generally are proliferated by chemical methods. From this we can see, that magnetize water is very cheap, simple and environmentally appropriate technology.

The detailed analyses and result experiments put question: may be magnetize field activates the process of acidizing or fracturing and causes a rate increase? For making a decision on this problem they took out equipment for treatment of injection water with the magnetize field and after the one month they checked the formation. They found that water rate decreases up to 90 m^3/ day and layer <u>A</u> intake 13.5 m^3/day, layer <u>B</u> – 27 m^3/ day, layer <u>D</u> – 49.5 m^3/ day. (Column 5, table 03).

They understand that the rate increases because of magnetize water and it was the result of treatment the water with magnetize field. If rate was increased in the result of the activation process of acidizing or fracturing then in this case, after takeoff the equipment for treatment the injection water with magnetize field, the intake capacity of well doesn't change and was equal to 120 m^3/ day. Experiment shows that the intake capacity of well decreases up to 90 m^3/ day (from the beginning date, before application of the magnetize field). It shows, that a process of acidizing or fracturing doesn't influence on the intake capacity of this well.

After this, they again build on specific equipment for treating the injection water, on the well head of the well. After seven months they found that the rate of the magnetize water injection increases up to 120 m^3/ day and layer <u>A</u> intake 39.6 m^3/ day, layer <u>B</u> – 80.4 m^3/ day (column 6, table 03).

Result of this experiment shows us that magnetize field can:

1) Increase intake capacity of well to 33%.

2) Increase activation layer with clay mineral and filtration property of the porous media.

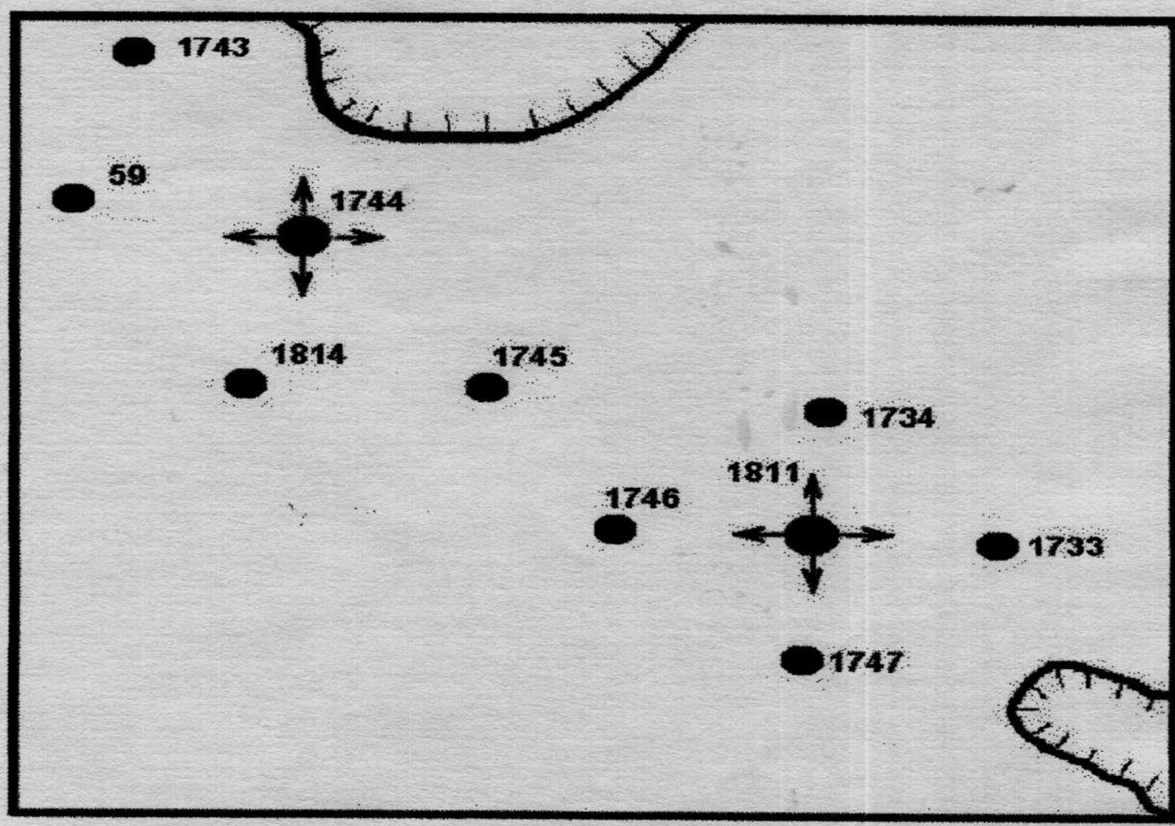


Figure 20 *Scheme in place production and injection wells*

4.2 Influences on the Rate of Production by Magnetized & Non-Magnetize Water Injection

After that they study the influence on the rate of production wells by magnetized water injection.

There idea was to injection the magnetize water in the well and research the dynamic oil rate production of the well around the injection well. If production of oil rate change dimension, it shows that the injection of the magnetize water influence on wells production rate. If oil well's rate of production is constant, it shows that injection magnetize water doesn't influence on rate of production wells.

For realizing this idea they found relatively small oil formation with one horizontal production layer; it was a research area of Bobrik layer Nurlat's oil field Tatariya (Russia) [look Figure 20 and 29]. Collector of this layer was terrigenous porous media, saturated oil with viscosity of $\mu = 100\ n{\cdot}s/\ m^3$ and gas factor – $G = 7\ m^3/m^3$.

Injection test shows that layer doesn't intake water, in the result for 4.5 years of formation development without water flooding and as a result the formation pressure decreases from the 9 MPa up to 6 MPa and oil rate gets decreased in average from 10 ton/day up to 2 ton/day.

In order to influence on formation, oil workers wanted to apply magnetize filed with water solution SAS (three sodium phosphate – has a property of alkali). On well head # 1811 they installed magnetize equipment and started the process of injection in the following order:

a) 140 m^3 solution SAS treatment with magnetize field.

b) After this, magnetize water pushes this solution SAS inside the porous media, to distant it from the injection well.

They research dynamic oil rate production wells # 1733,1734,1746,1747 (Figure 21 – 24).

4.2.1 Well # 1733

Figure 21 shows dynamic oil rate production in the wells # 1733. From this curve we can see that after 4.5 years from the beginning of development, formation pressure decreases from the 8 MPa up to 6 MPa and oil rate decreases from 10 ton/day up to 2 ton/day; last 14 months (before beginning injection magnetize water) well produce oil rate is constant and is equal to 2 t/day. While magnetize water begins injected in well #1811, then all production wells around this well increases the oil rate. Well#1733 increases oil rate up to 4.5 ton/day after 7 months from the beginning of injection magnetize water and continues to increase up to 5.5 t/day after 1.5 years from the beginning of injecting magnetize water. They understand that oil rate increases because of influence of magnetize solution SAS.

For separating the endowment of magnetize field to increase oil rate, they need to take off magnetize field and search oil rate. If oil rate changes the dimension in this case, magnetize field influences on oil rate, otherwise magnetize field doesn't influence on oil rate. For examination of this idea they take off magnetize equipment from well # 1811, continue injection water and research production well around this well. All production wells decrease oil rate.

On well # 1733 oil rate decreases up to 4.5 ton/ day, because magnetize field is absent. They understand this and after 14 months they build magnetize equipment on the well head of well # 1811 again; continue the injection of magnetize water and research the production well around this well.

On well # 1733 oil rate increases from the 4.5 ton/day till the 12 ton/day (it was more alike the beginning of oil rate 10.5 ton/day) after a year from the beginning of the second part magnetize water injection.

At the beginning the formation pressure in well # 1733 was 8 MPa, but it decreases till the 5.5 MPa before the beginning of injection of magnetize water; after this formation pressure increases till the 10 MPa (it is more alike beginning formation pressure) and was average of 10 MPa.

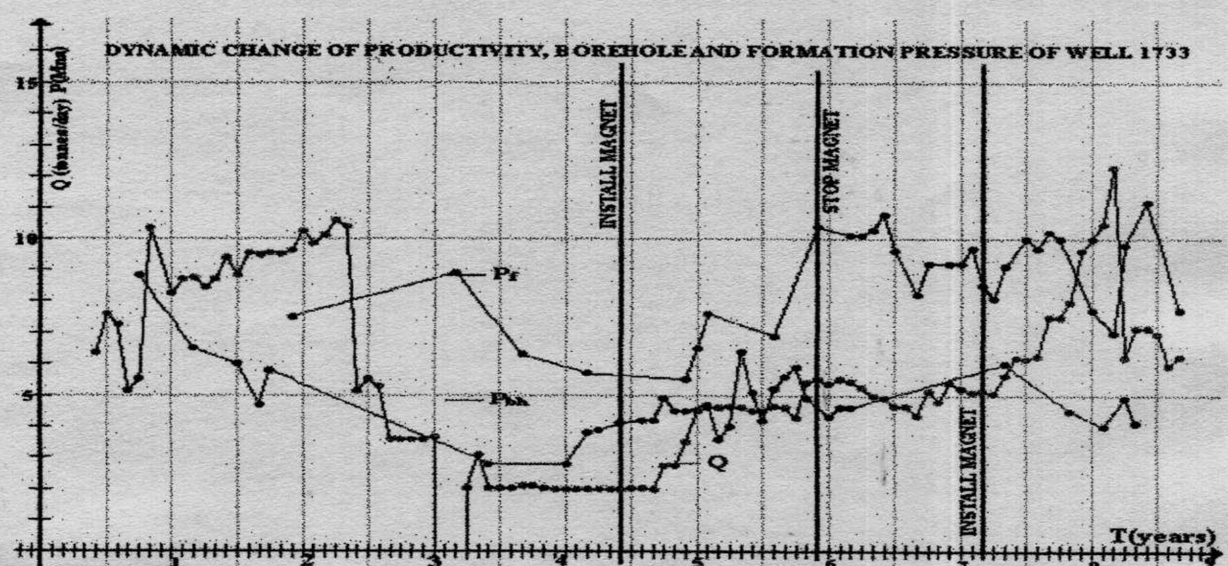


Figure 21 *Dynamic change of productivity, borehole and formation pressure of Well # 1733*

4.2.2 Well # 1734

On Figure 22 they show a dynamic oil rate production in well # 1734. From this curve we can see, that after 4.5 years from the beginning of development of formation pressure increases from the 7 MPa till the 10 MPa and oil rate decreases from the 13.5 ton/day till the 2.5 ton/day; last 14 months (before beginning of injection magnetize water) well production oil rate was constant, and was equal to 2.5 ton/day. They begin injection of magnetize water in well #1811 and a production output around this well increases oil rate; well # 1734 at the beginning - oil rate increases till the 5.5 t/day after 7 months (from the beginning of injection magnetize water) and continues to increase till the 15 ton/day (it is more alike as the beginning of oil rate 13.5 ton/day) after 1.5 years from the beginning of injection magnetize water. They stop the injection of magnetize water and after the 1 year oil rate decreases up to 8.5 ton/day. They understand that the magnetize field influences on the increase oil rate and they again build magnetize equipment on well head # 1811, then continue injection of magnetize water and research the production well around this well.

On the well # 1734, oil rate increases from 8.5 ton/day up to 15 ton/day, after the 1 year from the beginning of the second part of magnetize water injection.

At the beginning the formation pressure in well # 1734 was 7 MPa and all times it increases; at the beginning of injection magnetize water and after this formation pressure increases up to 13.5 MPa (it is more alike the beginning of formation pressure) and was average to 10.5 MPa.

In this well they had very interesting fact, formation pressure all times increases but oil rate decreases. Oil man knows that, a usual increase of formation pressure is stimulating an increase of oil rate. In this case, they could not know what happened? May be in this case, borehole pressure was smaller than bubble point pressure and formation pressure could not influence on rate.

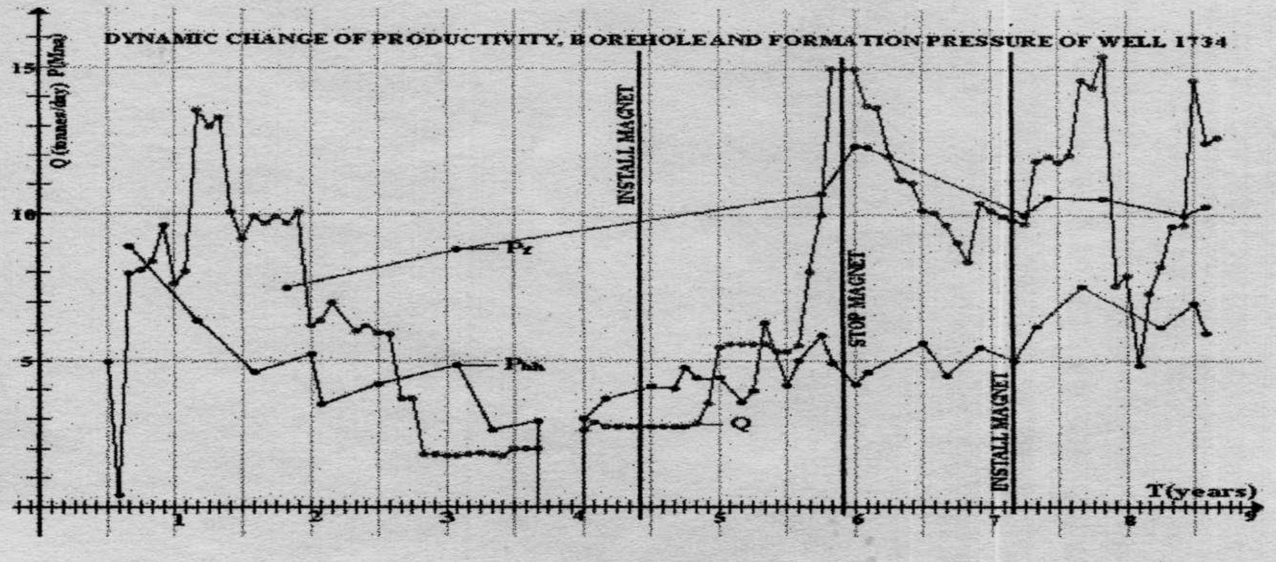


Figure 22 *Dynamic change of productivity, borehole and formation pressure of Well # 1734*

4.2.3Well # 1746

On Figure 23 they show a dynamic oil rate production in wells # 1746. From this curve we can see that after 3.4 years from the beginning of development of formation, pressure decreases from the 7 MPa up to 6.5 MPa and oil rate decreases from 10 ton/day up to 2 ton/day; last 30 months (before the beginning of injection magnetize water) well production oil rate was constant and was equal to 2 ton/day. When magnetize water begins injected in the well # 1811, then all production wells around this well increases an oil rate; in well # 1746 at the beginning an oil rate increases up to 6 ton/day and after 7 months (from the beginning of injection magnetize water) it continues to increase up to 12 ton/day (it is more likely as at the beginning when oil rate is 10 t/day) after 1.5 years from the beginning of injection of magnetize water.

While taking off magnetize equipment from the well # 1811, the oil rate of well # 1746 decreases from the 12 ton/day till the 6 ton/day after the 1 year because magnetize field was absent. They understand this and build magnetize equipment on the well head of the well # 1811; continue the injection of magnetize water and research the production well around this well.

On the well # 1746 oil rate increases from the 6 ton/day till the 12 ton/day after the 1 year from the beginning of injection magnetize water, i.e. the second part.

At the beginning formation pressure in well # 1746 was 7 MPa and all times it increases when they begin injecting the magnetize water; after this formation pressure increases up to 10.5 MPa (it is more alike as the beginning of formation pressure) and was average of 10 MPa.

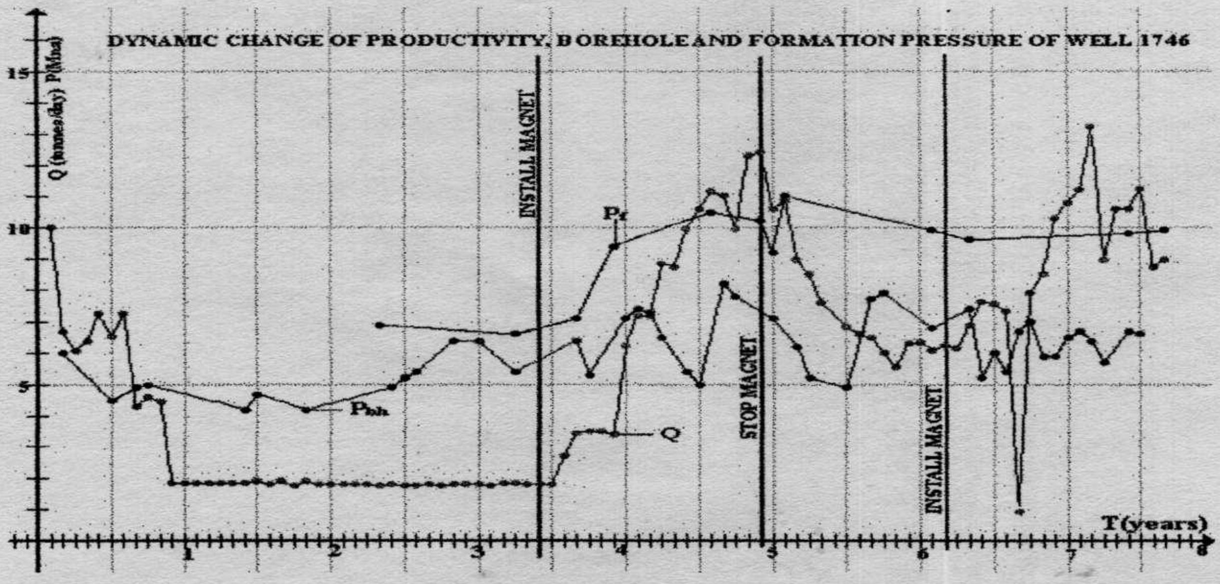


Figure 23 *Dynamic change of productivity, borehole and formation pressure of Well # 1746*

4.2.4 Well # 1747

On Figure 24 it is shown a dynamic oil rate production in wells # 1747. From this curve we can see, that after 4.5 years from the beginning of development, formation pressure decreases from 11 MPa to 9.5 MPa and oil rate decreases from 20 ton/day to 6.5 ton/day; last 2 months (before beginning of injection of magnetize water) well production oil rate was constant and was equal to 6.5 ton/day. After beginning of the injection of magnetize water in well #1811, a production from well# 1747 was increases up to 10 ton/day after 12 months (from the beginning of injection magnetize water) and continues to increase up to 13 ton/day after 1.5 years from the beginning of injecting magnetize water.

They understand that the oil rate increases because of influence of magnetize field.

For examination of this idea they take off magnetize equipment from well # 1811, continue injecting water and research production well around this well. On well # 1747 oil rate decreases from the 13 ton/day till the 11 ton/day after 8 months. They understand that and build the magnetize equipment on the well head of well # 1811; continue the injection of magnetize water and research the production well around this well.

On the well # 1747 oil rate was 16 ton/day after the 1 year from the beginning of the second part of the injection of magnetize water.

At the beginning the formation pressure in well # 1747 was 11 MPa and it increases all times; after beginning of injection of magnetize water the formation pressure increases up to 12 MPa (it is more like as the beginning of formation pressure) and was average to 11 MPa.

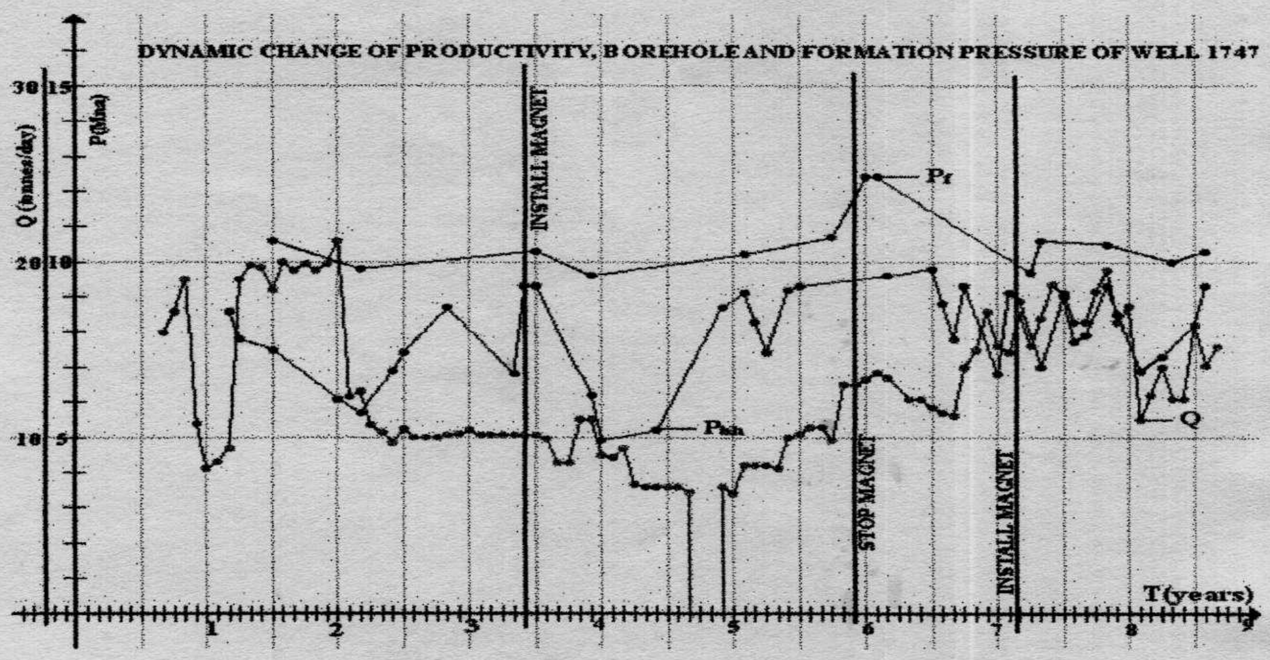


Figure 24 *Dynamic change of productivity, borehole and formation pressure of Well # 1747*

From this experiment on formation we understand that, injecting of magnetize water with SAS solution , increases rate of injected well and consequently it also increases oil rate of production wells. This result shows that, in future injecting the magnetize water in formation shell gives best results (as in formation water, it is dissolved many salts and solutions having property of SAS).

The results of experiments show that after injecting magnetize water with SAS solution, formation pressure increases and a clear increase of oil rate - is it for influence of magnetize processing or for increase of formation pressure?

To answer this question, in two different places they did the injection of the formation water (injection well # 1744 and production wells # 59, 1743, 1745, 1814) and magnetize water (injection well # 3003 and production wells # 332, 3004, 3045, 3046, 3048, 3049) and start researching of dynamic oil rate production wells in order to have results for comparison.

Let us study how Non-Magnetize Water influences on oil rate production in wells # 59, 1743, 1745, 1814. Dynamics of oil rate production in wells are show on Figure 25 – 28.

4.2.5 Well # 1745

On Figure 25 they show a dynamic oil rate production in well # 1745. From this curve we can see, that after 6 month from the beginning of injecting water, oil rate increases from 2.5 ton/day up to 7 ton/day in 25 months; after this decrease up to 4 ton/day and gets stabilized till the end of research. As a whole, the average oil rate was 4 ton/day.

Formation pressure average was constant and was equal to 10 MPa because water injection starts from the beginning of production.

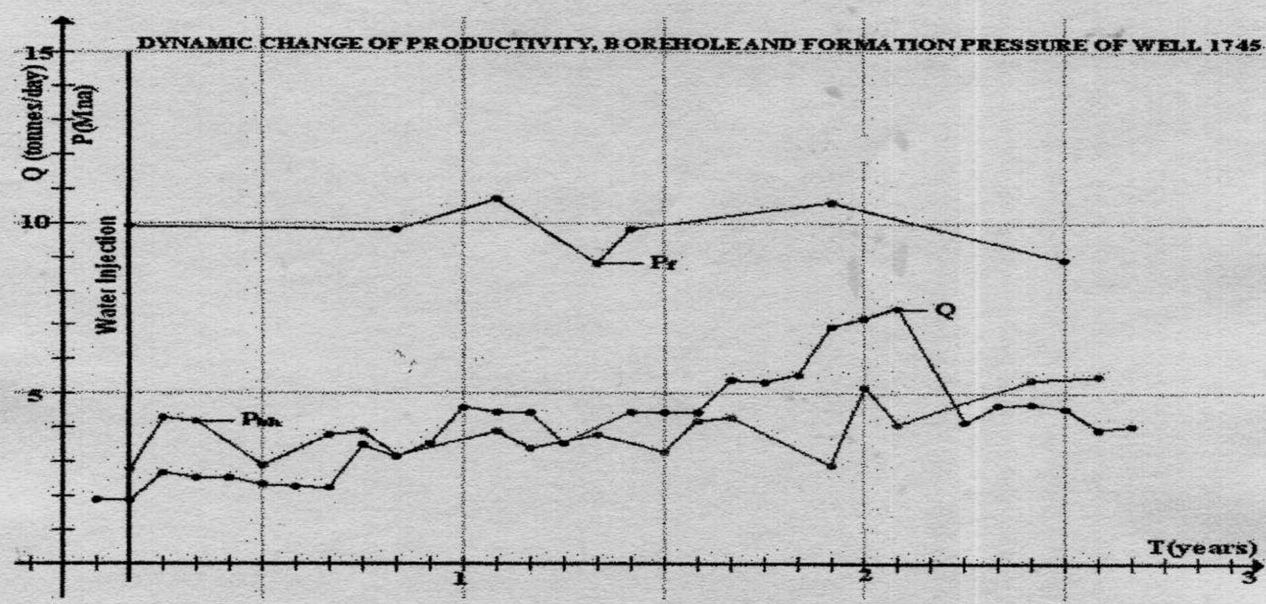


Figure 25 *Dynamic change of productivity, borehole and formation pressure of Well # 1745*

4.2.6 Well # 59

On Figure 26 it is shown a dynamic oil rate production in well # 59. From this curve we can see that after 10 months from the beginning of injecting water, oil rate increases from 3.5 ton/day up to 7 ton/day in the 1 year and after this rate decrease up to 1 ton/day. As a whole, an average oil rate was 4 ton/day.

Formation pressure increases from 11 MPa up to 12.5 MPa, because of water injection starts from the beginning of production.

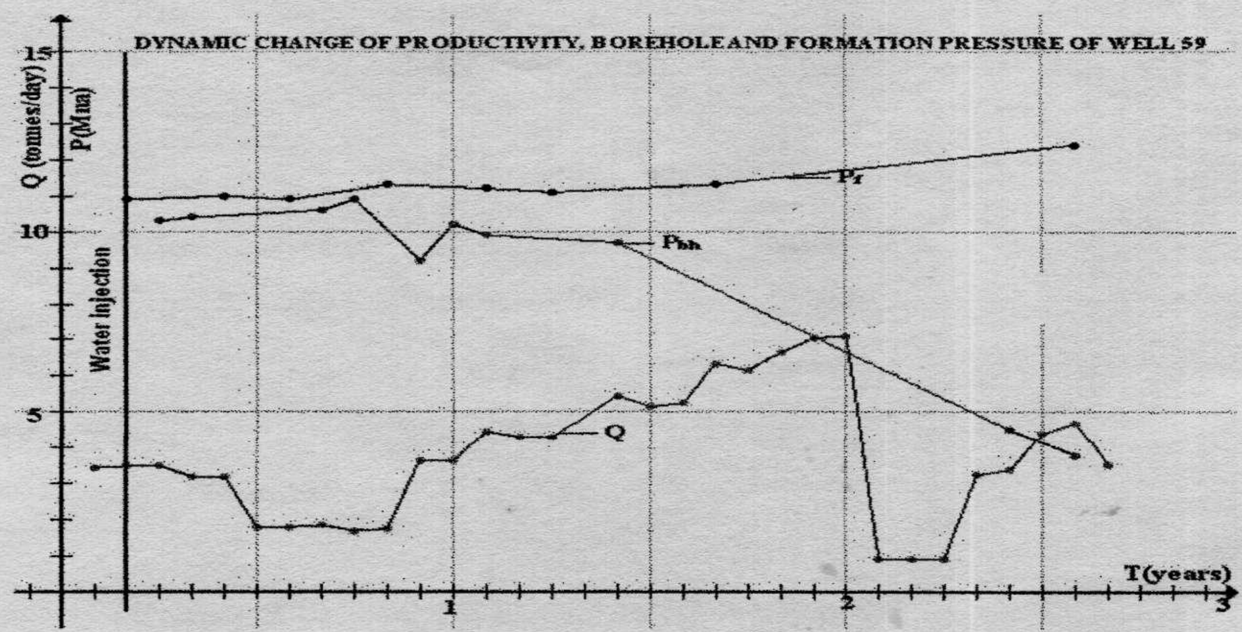


Figure 26 *Dynamic change of productivity, borehole and formation pressure of Well # 59*

4.2.7 Well # 1814

On Figure 27 it is shown a dynamics of oil rate production in well # 1814. From this curve we can see that during experiment from the beginning of injecting water, oil rate was constant and was equal to 2 ton/day.

Formation pressure increases from 10 MPa till 12 MPa, because water injection is from beginning production.

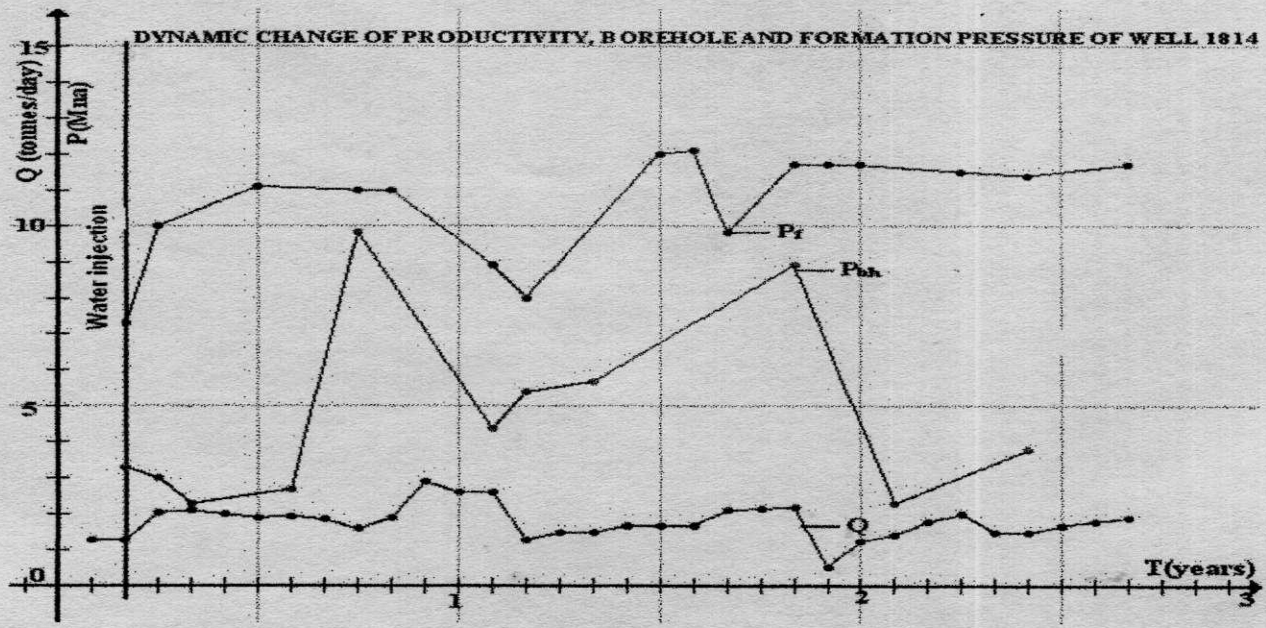


Figure 27 *Dynamic change of productivity, borehole and formation pressure of Well # 1814*

4.2.8 Well # 1743

On Figure 28 it is shown dynamic oil rate production in well # 1743. From this curve we can see, that after 6 months from the beginning injection water, oil rate increases from 2.5 ton/day to 4 ton/day in 2 years and after this it decreases up to 2.5 ton/day. As a whole, the average oil rate reaches to 3 ton/day.

Formation pressure increases from 9 MPa to 9.5 MPa, because water injection starts from the beginning of production.

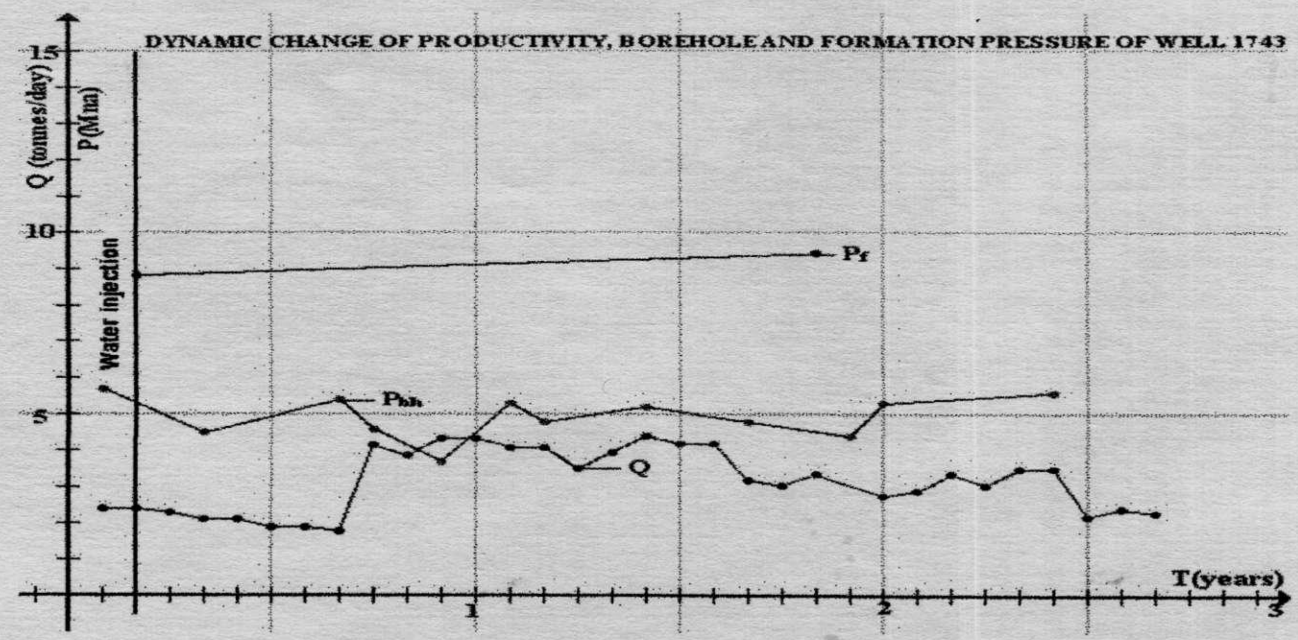


Figure 28 *Dynamic change of productivity, borehole and formation pressure of Well # 1743*

Let us study how injection water influences on oil rate production in wells # 332, 3004, 3045, 3046, 3048, and 3049. Dynamic of oil rate of production wells are shown on Figure 30 – 35.

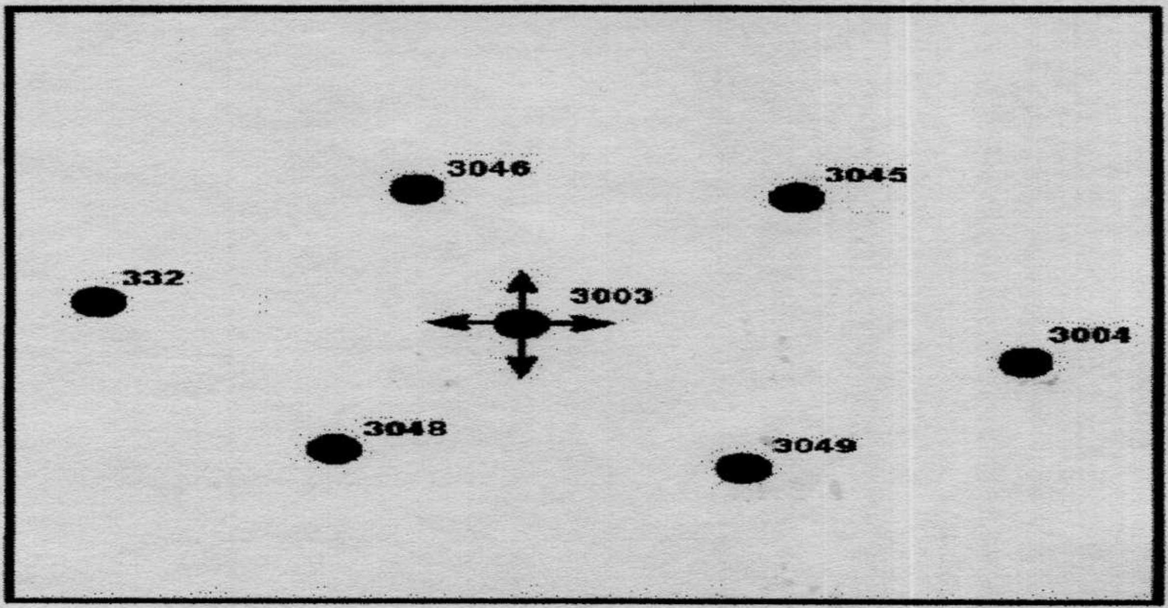


Figure 29 *Scheme in place production and injection wells*

4.2.9 Well # 3049

On Figure 30 it is shown a dynamics of oil rate production in well # 3049. From this curve we can see that 6 months before injecting magnetize water, oil rate average was constant and was equal to 2.5 ton/day. After 9 months from the beginning of the magnetize water injection, oil rate increases from 3.5 t/day up to 10.5 t/day at the end of 2 years. From 17 months from the beginning of injecting magnetize water, oil rate rapidly increases. Formation pressure increases from 8 MPa up 15.5 MPa.

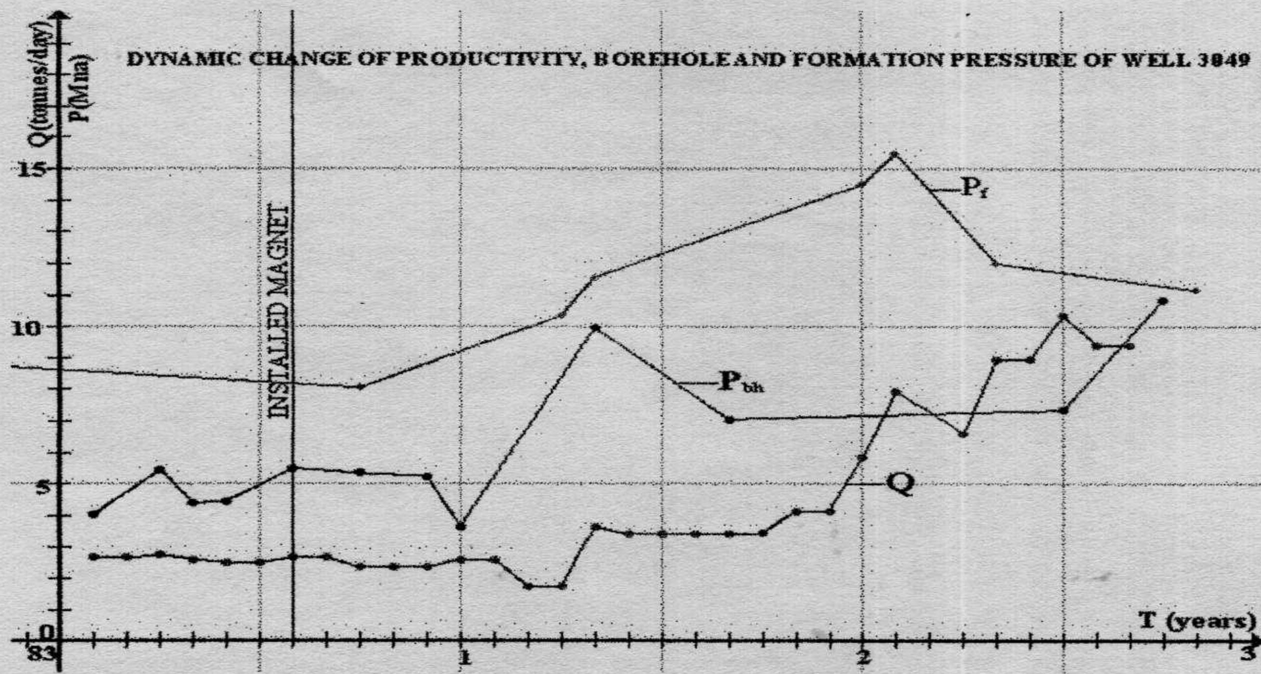


Figure 30 *Dynamic change of productivity, borehole and formation pressure of Well # 3049*

4.2.10 Well # 3004

On Figure 31 it is shown a dynamics of oil rate production in well # 3004. From this curve we can see that 6 months before injecting magnetize water, oil rate average remains constant and equals to 3 ton/day. After 10 months from the beginning of injecting magnetize water, oil rate increases from 3 ton/day up to 17 ton/day by the end of 2 years. 7 months from the beginning of injecting magnetize water, oil rate rapidly increases. Formation pressure increases from 7 MP up to 10.5 MPa.

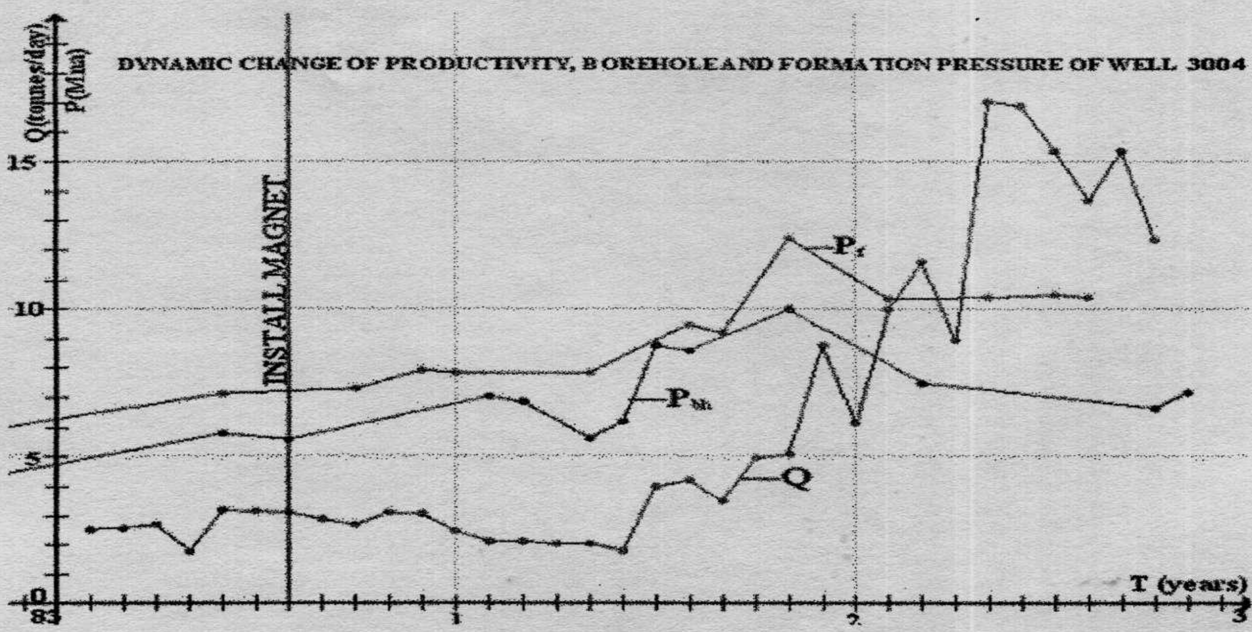


Figure 31 *Dynamic change of productivity, borehole and formation pressure of Well # 3004*

4.2.11 Well # 332

On Figure 32 it is shown a dynamics of oil rate production in well # 332. From this curve we can see that 6 months before injecting magnetize water oil rate average was constant and was equal to 2 ton/day. After 4 months from the beginning of injection magnetize water, oil rate increases from 2 ton/day up to 10 ton/day by the end of experiment. From 11 months beginning form the injecting magnetize water, oil rate rapidly increases. Formation pressure increases from 6 MPa till 11 MPa.

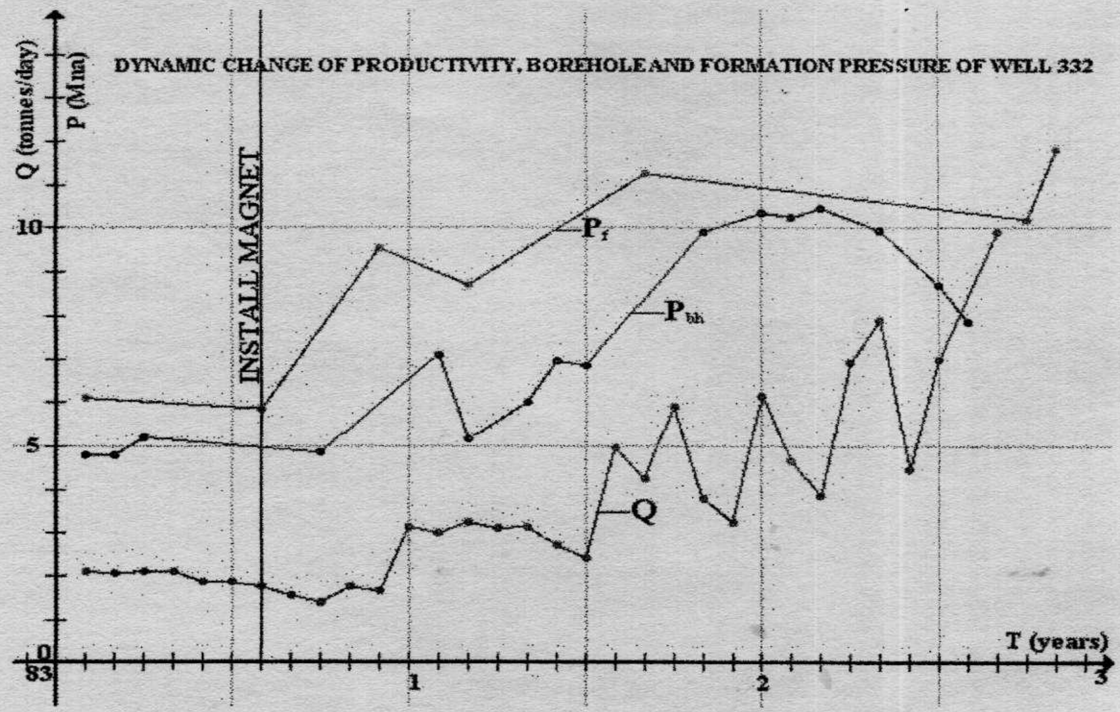


Figure 32 *Dynamic change of productivity, borehole and formation pressure of Well # 332*

4.2.12 Well # 3048

On Figure 33 it is shown a dynamics of oil rate production in well # 3048. From this curve we can see that 6 months before injecting magnetize water, oil rate average was smaller than 2 ton/day. After 6 months beginning from injecting magnetize water, oil rate increases from 2 ton/day to 6 ton/day in the end of experiment. 6 months from the beginning of injection magnetize water, oil rate rapidly increases. Formation pressure increases from 6 MPa till 11 MPa.

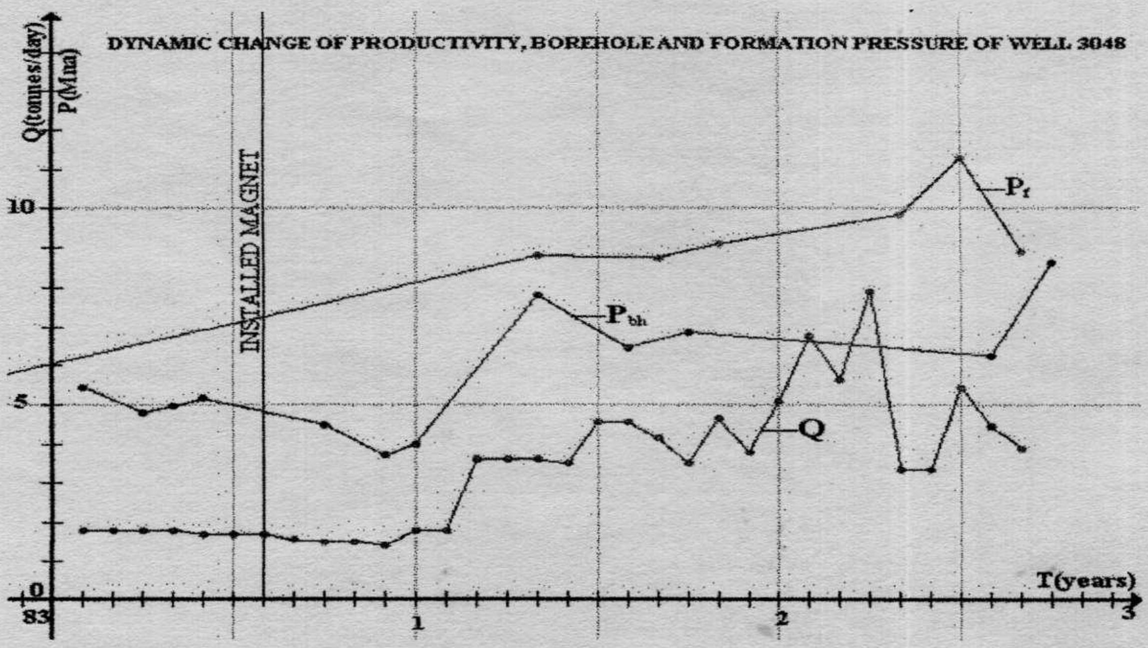


Figure 33 *Dynamic change of productivity, borehole and formation pressure of Well # 3048*

4.2.13 Well # 3045

On Figure 34 it is shown a dynamics of oil rate production in well # 3045. From this curve we can see that 6 months before injecting magnetize water oil rate was average to 2 ton/day. After 6 months beginning from the injection of magnetize water, oil rate increases from 2 ton/day up to 13 ton/day in the end of experiment. From 13 months beginning injection magnetize water oil rate rapidly increases. Formation pressure increases from 5.5 MPa to 12 MPa.

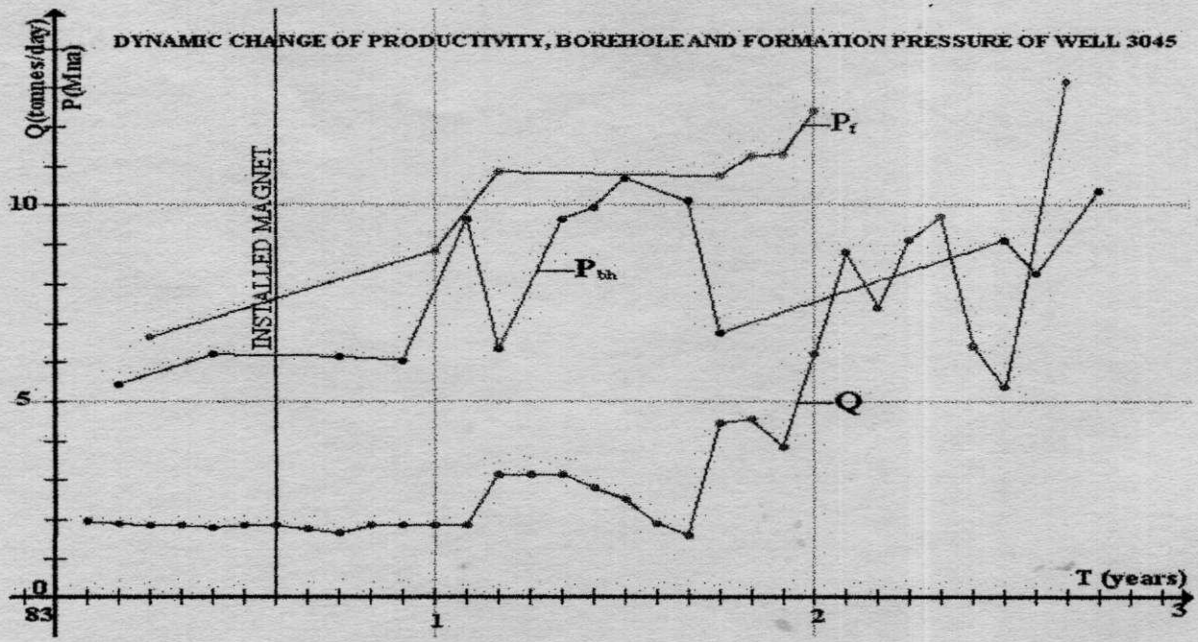


Figure 34 *Dynamic change of productivity, borehole and formation pressure of Well # 3045*

4.2.14 Well # 3046

On Figure 35 it is shown a dynamic oil rate production in well # 3046. From this curve we can see, that 6 months before injection, magnetize water, oil rate averages to 1.5 ton/day. After 6 months they start injection magnetize water and as its consequence, oil rate in production well increases from 1.5 ton/day up to 6 ton/day and by the end of this experiment 6 months after starting the injection magnetize water oil rate rapidly increases. In this case, formation pressure also increases from 5.5 MPa up to 11 MPa.

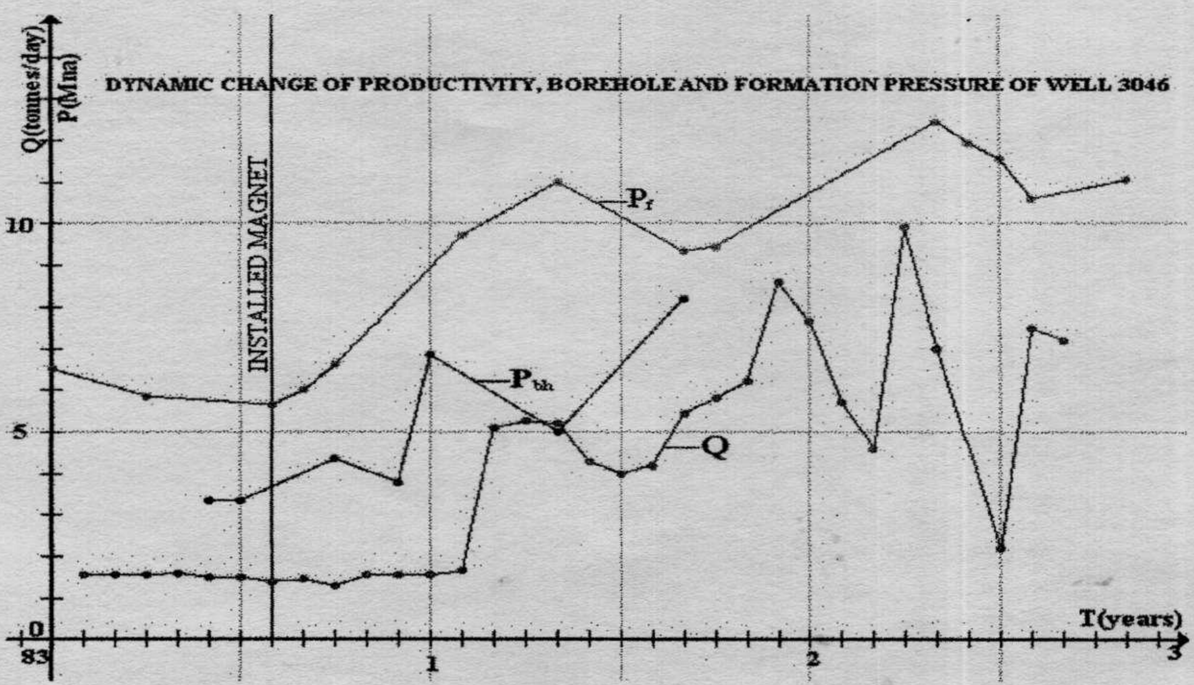


Figure 35 *Dynamic change of productivity, borehole and formation pressure of Well # 3046*

If we compare these both results **we can conclude that injection of water increase oil rate averagely in 2.2 times, but magnetized water injection increases oil rate averagely 5 times**. So, injection magnetized water increases the oil rate in production wells.

4.3 Observation:

Using magnetize field we can:

1. Increase oil rate production wells average 30%;
2. Increase intake capacity of injection wells 33%;
3. Increase effectiveness treatment of borehole zone.

4.4 White Tiger (also Bach Ho) Oil Field

Another example of magnetize water injection is the White Tiger (also Bach Ho) oilfield. It is a major oilfield in the Cuu Long basin of the South China Sea located offshore due east of the Mekong Delta of Vietnam. The field contains major reserves hosted within highly fractured granitic basement rocks. The Cuu Long basin is a rift zone developed during the Oligocene to Early Miocene. The rift occurred in Jurassic to Late Cretaceous granite to granodiorite intrusions. The fractured granitic rocks occur as a horst overlain and surrounded by Upper Oligocene lacustrine shale source rocks.

White Tiger is not the only oil field convincingly shown to be hosted in granite however, inspection of the seismic profile of the area shows faulted basement passive margin which is sealed by an on lapping sedimentary sequence.

It is plausible that the oil has migrated laterally from the lowermost, mature sediments into the fault systems within the granite. The seismic profile shows a definite basement horst with on lapping sedimentary source rocks, draped by a reservoir seal. This trap view would see the oil migrate up the horst bounding faults from the lower source units, into the trap unit draped over the top.

The White Tiger field was developed by the joint Vietnamese Russian entity Vietsovpetro, in the 1980s and 1990s. Upon examination of the source rock and oil content, petro-geologists have emphasized that the oil's components indicate a lacustrine organic facies with lipid-rich, land-plant debris and fresh-water algal material, refuting theories of a biogenic origin in this area.

Petroleum samples from the White Tiger oilfield contain biomarkers which "indicate a lacustrine organic facies with lipid-rich, land-plant debris and fresh-water algal material," which indicate that it is of biological origin.

4.5 Electromagnetic Coil Tubing

The present invention describes an apparatus and a method to extract hydrocarbon oil or other fluids which are trapped in subterranean reservoirs, and which cannot be readily removed by conventional means. The apparatus utilizes one or more electromagnetic coils which are centrally located in a wellbore hole which is positioned in a portion of a subterranean fluid containing formation from which it is desired to extract hydrocarbon or other fluids. It is a purpose of the present invention to increase the recovery of hydrocarbon and other fluids from hydrocarbon bearing deposits using electromagnetic attraction.

The process and apparatus include one or mole electromagnetic coils which are attached to a centrally located shaft or tube which is inserted into or is part of an oil (or other liquid producing) well. These electromagnets generate a magnetic field which extends radically from the tubing of subterranean oil (or other fluid) well. These coils are energized with direct current, which results in a strong attraction of magnetic particulate matter and fluids towards the central tubing. Electric current may be supplied intermittently to the coils, there by jolting the particulate matter and speeding its flow.

The direction of the electrical current to the coils can be periodically reversed. Particulate matter given one charge will then be subject to an opposing charge, which speeds up movement to the wellbore. Particulate matter, in moving to the wellbore, will then be subject to an opposing charge, which speeds up movement to the wellbore. Particulate matter, in moving to the wellbore, will carry along hydrocarbon or other fluid, thereby causing fluid flow to the wellbore to increase.

In one variation of this invention, a vibration sensitive transistor is inserted into the electrical circuit in order to cause the vibrations of the oil well pump to generate some electricity which can be used to power the magnets.

In another variation, a capacitor is inserted in the electrical circuit to provide bursts of electricity to the magnets in order to stimulate fluid flow.

4.4.1 Drawback

In the case of this electromagnetic coil apparatus, there are three major drawbacks in the comparison of magnetize water injection;

1) In this apparatus the electric wires are open;
2) Diameter of the tool is more than the production zone diameter;
3) Generally attraction of magnetic particulate matters will not push the oil towards the borehole but in fact they will reduce the permeability of the porous medium.

4.6 Applications

Magnetize water injection can be utilize for stimulation purpose of damage formation, near the borehole zone, because of the clay content in mud, by circulating the magnetize water in the borehole and as the result swelling of the clay will decreases.

Beside this we can also avoid the reduction in permeability after the perforation because of the mud interaction with formation, by passing the mud through magnetic field. For example; In case of the Tatariya oil field, the permeability calculated by geo-physical way was 600 md, but after perforation the permeability was only 60 md and the reason of reduction in permeability was clay swelling. For avoiding this problem they passed the mud through magnetic field and as a result the permeability after perforation was about 450 md.

4.6.1 Earth Magnetic Field

Instead of using magnetize water injection; we can enhance the oil recovery by considering the direction of water injection with respect to the Earth's Magnetic Field. For this purpose we took six bed models of same content (four are made up of non-magnetic material as copper), put them in different directions with respect to the Earth's Magnetic Field, saturated them with oil and then injected the normal water. We observed that the best ultimate recoveries were 39% in case of West – East (Iron) direction and 60% in case of South – North directions.

Table 04 *Direction of Magnetic Field of Earth*

DIRECTION OF MAGNETIC FIELD OF EARTH	η = (Ultimate Recovery)	η = (Waterless Recovery)
South – North	0.600	0.285
North – South	0.450	0.152
South – North (Iron)	0.660	0.343
East – West	0.600	0.150
West – East	0.400	0.137
West – East (Iron)	0.580	0.390

CHAPTER 05

NORWEGIAN RESERVOIRS

CHAPTER 05

NORWEGIAN RESERVOIR

5.1 Offshore Sandstone Reservoirs

A summary is given of parameters for North Sea Sand Stone Reservoirs. Even though it may be impossible to identify the key parameters for Magnetized water injection in general, without detailed and specific reservoirs knowledge, many existing or contemplated methods may be judged as promising or unrealistic based on a small set of general reservoir parameters.

The two chalk fields Ekofisk and Eldfisk are included at the bottom of the tables for the purpose of comparison.

The parameters are presented in tables (Properties Table) and they give information about formation properties, fluid properties and composition, and reservoir temperature and pressure. Initial data are reported, as a range or an average value for most of the parameters. In some instance, however, a typical or representative value has been selected, e.g. depth to fluid contact.

The Volume Table contains reservoir area and bulk volume; initial hydrocarbon volumes in place and recoverable reserves; production period and method; cumulative produced volumes of oil and gas.

The data in the Properties Table and the reservoir area and bulk volume have been reported to this monograph by the operators of the fields. The rest of the data in the Volume Table is taken from the resource of data base of the Norwegian Petroleum Directorate (NPD). Note that since two different data sources have been used, there is not necessarily a full consistency between specified bulk volume and initial oil in place.

5.2 Parameters

First are presented explanatory lists where the parameter categories appear in the same order as in the tables.

Special Conventions: The field of an unknown parameter is left blank and a dash, - , indicates irrelevance.

Table 05 *Properties Table's Abbreviations of Norwegian (North Sea) Sand Stone Reservoirs*

Group/Formation	IDS	L-BC	L- DEF	N-mela
Abbreviations	Intra Dunlin Sand	Lunde-BC	Lunde-DEF	Nord-Mela

Geological Ages	Cr	Da	E	J
Abbreviations	Cretaceous	Danian	Eocene	Jurassic
Geological Ages	Ma	P	T	PREFIX (M / L)
Abbreviations	Maastrichtian	Paleocene	Triassic	Middle / Late

Trap Types	**An**	**ef**	**h**	rf	a	**U**
Abbreviations	Anticlinal	Eroded Fault Block	Horst	Rotated Faults	Stratigraphic	Structural

Symbol	D	owc	go/wc	h_t	h_n
Abbreviations	Depth to Crest (m) Subsea	Oil-Water contact (m) Subsea	Gas-Oil or Gas – water Contact (m) Subsea	Gross Reservoir Thickness (m)	Net Reservoir Thickness (m)
Symbol	θ	H_g	H_o	K_v / K_h	K_h
Abbreviations	Dip Angle (degrees)	Gas Column Thickness (m)	Oil Column Thickness (m)	Permeability Ratio	Horizontal Permeability (md)
Symbol	S_{oi}	S_{orw}	S_{org}	ϕ	ρ_o
Abbreviations	Initial Oil Saturation	Residual Oil Saturation (if water flooded)	Residual Oil Saturation (if gas flooded)	Porosity (%)	Oil Density (Kg/m^3)
Symbol	V_{clay}	γ_g	ρ_c	μ_g	μ_c
Abbreviations	Clay Content (ratio)	Gas Gravity (air =1)	Condensate Density (Kr/m^3)	Gas Viscosity (cp)	Condensate Viscosity (cp)
Symbol	μ_o	p_b	p_d	R_s	C_L
Abbreviations	Oil Viscosity (cp)	Bubble Point Pressure (bar)	Dew Point Pressure (bar)	Solution Gas / Oil Ratio	Condensate Content

				(Sm^3/Sm^3)	$Sm^3/(MSm^3$ gas)
Symbol	B_o	B_g^{-1}	C_1	C_{2-4}	C_{5-12}
Abbreviations	FVF of Oil (Rm^3/Sm^3)	Expansion Factor for Gas (Sm^3/Rm^3)	Mole Percent C_1	Mole Percent C_2-C_4	Mole Percent C_5-C_{12}

Symbol	C_S	C_{Di}	T	P
Abbreviations	Salinity (mg/l)	Concentration of Divalent Ions (mg/l)	Reservoir Temperature (°C)	Reservoir Pressure (bar)

Table 06 *Volume Table's Abbreviations of Norwegian (North Sea) Sand Stone Reservoirs*

Symbol	A	V_b	N	N R_s
Abbreviations	Reservoir Area (Km^2)	Gross Rock Volume (10^6 Sm^3)	Initial Oil In Place (10^6 Sm^3)	Initial Associated Gas In Place (10^9 Sm^3)
Symbol	G_{Fi}	R-oil	R-gas	R-ngl
Abbreviations	Initial Free Gas In Place (10^9 Sm^3)	Oil Reserves (10^6 Sm^3)	Gas Reserves (10^9 Sm^3)	NGL Reserves (10^6 Tons)
Symbol	N_p	G_p	g / w	p
Abbreviations	Cumulative Oil Production (July 1991, 10^6 Sm^3)	Cumulative Gas Production (July 1991, 10^9 Sm^3)	Gas / Water Injection	Pressure Depletion

5.3 Comments

Some fields specific comments are given in this paragraph since the data reported in some case cannot easily be included in sample table.

The same symbols and units are used as in the tables, and the units are therefore not repeated here.

- Balder:

Mole Fraction $C_{5\text{-}9}$ = 8.6

Range of Pb = 145-165

- Brage:

Statfjord; mole fraction $C_{5\text{-}7}$ = 14.78

Fensfjord; mole fraction $C_{5\text{-}7}$ = 5.79

- Gullfaks:

Brent; Pb = 217-270 and R_s = 87.5-100

Cook = Reported parameters in Properties Table and A and V_b in Volume Table are for Phase-02

- Gullfaks Sor:

Brent; owc = 3300-3470, Brent; goc = 3321-3220. Composition in table is for oil. Gas composition is C_1 = 84%, C_2 = 10%, C_3 = 4%

Statfjord; gas composition is C_1 = 85%, C_2 = 9%, C_3 = 4%

- Heidrum

Tilje and Are; owc = 2415-2452, goc = 2292-2314

Tilje; μ_o = 0.84-1.63, Pb =221-245, R_s = 78-114, B_o = 1.21-1.31

Tilje; gas composition is C_1 =41-46%, $C_{2\text{-}4}$ =7-11%, ($C_{5\text{-}12}$, Co_2, N_2) = 43-51%

- Oseberg

R_s = 132-158

- Smorbukk

This condensate field only has oil in Tilje with R_s = 440. A producing GOR of 1458 is reported from the gas zone of Tilje. For Garn, Ile, Tofte are reported producing GOR's in the range 840-1700.

Ile; Ile-01 go/wc = 4085

Tilje; B_o = 2.42-2.64, B_g^{-1} = 224-238

- Smorbukk Sor

Garn; Pb = 330-393, R_s = 295-570, B_o =1.95-3.00

Tilje-02; R_s = 362-513

- Snorre

Statfjord; owc = 2595-2599, ρ_o = 710-765, μ_o = 0.77-0.84, Pb = 90-126, R_s = 58-84, B_o =1.19-1.27, gas composition C_1 =20-26%, $C_{2\text{-}4}$ = 20-22%, $C_{5\text{-}9}$ = 24-26%, C_{10+} = 24-34

Lunde-BC; owc = 2574-2595, $C_{5\text{-}9}$ = 20%, C_{10+} = 25

Lunde-DEF; owc = 2561-2574, C_S = 34,000-42,000, C_{Di} = 2000-2500, $C_{5\text{-}9}$ = 19%, C_{10+} = 21

- Ula

Varying contact owc = 3789, 3759, 3714, 3561, 3544, 3491

- Frigg

Initial gas saturation is reported in the table in the S_{oi} column. Initial oil saturation in the oil rim was 73.9

- Midgard

Ile; composition in the table is for gas. Oil composition is 47, 16, and 37. Initial saturation in the table is for gas. Initial oil saturation is 80. Oil rock volume is reported as 47.10^6 m^2

- Sleipner Vest

Tabulated values are from the southern part of the field. The field has varying gwc. Range of condensate content $C_L = 250\text{-}470$.

For the northern part, the following values have been reported: $\gamma_g = 0.86$; $\rho_c = 637$, $\mu_g = 0.041$; $Pd = 431$; $C_L = 250\text{-}470$; $B_o = 1.688$; $Bg^{-1} = 271.6$; $C_1 = 77.29\%$, $C_{2\text{-}4} = 13.51\%$, $C_{5\text{-}12} = 4.52\%$, $p = 447.5$.

- Troll

Sognafjord; owc = 1549-1569, goc = 1543-1547, ρ_o = 890-910, μ_o = 1.3-1.8, R_S = 55-69. Composition in table is for oil and the gas composition is $C_1 = 93\%$, $C_2 = 4\%$, $C_3 = 3\%$.

Table 07 - A *Properties of Norwegian (North Sea) Sand Stone Reservoirs*

Field	*Group/ Form.*	*Age*	*T*	*D m ss*	*owc m ss*	*go / wc m ss*	h_f *m*	h_n *m*	Θ °	h_g *m*	h_o *m*	Φ *%*	k_h *md*
Balder	Heimdal	P	au	1680	1760	-	116	95	0-2	-	80	33	1-10 D
Brage	Statfj.	EJ	h	2300	2381	-	110	88	0	-	61	23	1 D
	Fensfj.	LJ	an	2080	2149	-	35	20	1-2	-	27	26	100
Draugen	Rogn	LJ	an	1596	1638	-	0-46	0-46	-	-	0-37	32	6-7 D
Gulf.	Brent	MJ	u	1740	1947	-	250-300	190	12	-	207	31	3.2 D
	Cook	EJ	u	1750	2090	-	50-75	48	0-15	-	340	28	550
	Statfj.	EJ	u	1860	2028	-	175	105	1-2	-	168	27	1 D
Gulf.-S	Brent	MJ	u	2850			300	135	17	0-470	5-250	20	5-250
	Statfj.	EJ	u	3000	3365	3222	260	170	17	222	143	20	0.01-3 D
	Lunde	LT	a	3250	3680	-	>420	>50	17	-		15	0-20
Gyda	Farsund	LJ	au	3700	4155	-	50	45	4	-	45	17	30
Heidrun	Fangst	MJ	h	2080	2478	2283	70	63	7	203	195	28	0.7-20 D
	Tilje	EJ	h	2100	2452	2292	120	90	6	203	130	25	0.07-2 D
	Are	EJ	h	2240	2415	2314	205	103	3	63	130	27	0.1-10 D
Oseberg	Brent	J	ef	2120	2711	2497	186	111	8	377	214	23	0.5-3.5 D
Smorb.	Garn	J	u	3952	-	4077	40	36	6	125	-	11	>10
	Ile	J	u	4025	-	4550	60-70	2-45	6	525	-	12	>10
	Tofte	J	u	4143	-	4305	80	47	6	163	-	12	>10
	Tilje	J	u	4208			140-185	7-102	6			14	>10
Smorb.-Sor	Garn	J	u	3799	3982	-	87.5	70.6	<3	-	182.5	15	2-850
	Ile	J	u	3925	-	4039	71	21	<3	114	-	14	6
	Tilje-3	J	u	4125	-	4242	65		<3	117	-	12	1.7
	Tilje-2	J	u	4190	4242	-	52		<3	-	52	17	60
Snorre	Statfj	EJ	u	2300	2595	-	90	40	9	-	120	24	1000

	L-DEF	LT	u	2360	2561	-	570	140	8	-	90	24	380
	L-BC	LT	u	2340	2574	-	180	45	8	-	50	24	125
Statfj.	Brent	MJ	u	2360	2586	-	155	115	7	-	226	28	2300
	Statfj.	EJ	u	2575	2806	-	125	63	7	-	231	21	1000
Statfj.-N	Volgian	LJ	u	2600	2718	-	46	37	10	-	118	25	785
	Brent	MJ	u	2620	2718	-	140	105	10	-	98	25	1000
Ula	Ula	LJ	u	3345	3561	-	110	100	10	-	90	17	300
Veslef.	Brent	MJ	u	2755	2906	-	125	71	1-3	-	151	18	200-700
	IDS	EJ	u	3000	3079	-	52	12	1-3	-	79	20	10-600
	Statfj.	EJ	u	3170	3208	3194	>200	>100	1-3	24	14	16	50
Frigg	Frigg	E	a	1785	1957	1948	55	52	0	50	9	28	0.5-4 D
Heimdal	Heimdal	P	an	2020	2150	2146	0-126	0-101		0-126	4	26	1000
Midgard	Garn	MJ	h	2300	-	2490	50	49	<10	200		29	5000
	Ile	MJ	h	2300	2500	2490	65	62	<10	200	12	27	5000
	Tilje	EJ	h	2350	-	2490	220	110	<10	200		25	1000
Sleip.-V	Hugin	MJ	au	3450	-		203	70-158	10	88-160	-	22	10-450
Sleip.-ø	Heimdal	P	u	2260	-	2417	100	95	0	157	-	27	400
Snohvit	Sto	LJ	u	2300	2419	2405	70-95	62-85	2	105	14	16	250
	N-mela	MJ	u	2300	2419	2405	60-105		2	105	14	14	10
Troll	Sognefj.	LJ	rf	1300	1559	1547	230		1-4	230	0-26	27	10^3-10^4
Ekofisk	Ekofisk	Da	u	2900	3200	-	170	120	3-7	-	170	33	1-100
	Tor	Cr	u	3030	3250	-	85	60	3-7	-	85	30	1-100
Eldf.-A	Ekofisk	Da	u	2683		-	45	45	7-9	-	45	35	1.0
	Tor	Ma	u		2896	-	30	30	7-9	-	30	35	2.5
Eldf.-B	Ekofisk	Da	u	2807	2940	-	76	76	5-7	-	76	33	1.0
	Tor	Ma	u			-	91	91	5-7	-	91	33	3

Table 07 – B *Properties of Norwegian (North Sea) Sand Stone Reservoirs*

Field	*Group/ Form.*	$k_v - k_h$	S_{oi} %	S_{orw} %	S_{org} %	*V clay* %	ρ_o	γ_g	ρ_c	μ_o *cp*	μ_g *cp*	μ_c *cp*
Balder	Heimdal	0.1-0.5	85	15		0-25	914	0.677	-	3.0	0.016	-
Brage	Statfj.	0.1-0.2	68	15	7		835		-	0.7		-
	Fensfj.	0.1-0.4	48	22			843	0.766	-	0.58	0.024	-
Draugen	Rogn	0.6-0.7	72-85	30-35	-	<10	824	1.010	-	0.68		-
Gulf.	Brent	0.5-0.9	80	30		5-25	882	0.705	-	1.12		-
	Cook	0.05-0.2	72	21		20-40	844	0.821	-	0.43		-
	Statfj.	0.5	85	30		15	838	0.810	-	0.40		-
Gulf.-S	Brent	0.1	70-95	32	30	10	860	0.670	790	0.35	0.035	
	Statfj.	0.1	60-85	28	30	5	860	0.670	790	0.65	0.035	
	Lunde	0.1	40-70			15	865		-	0.41		-
Gyda	Farsund	0.1-1	47-83	15	-	0-30	822	1.030	-	0.28		-
Heidrun	Fangst	0.9	86-97	25-35	5-15	0.8	882	0.660		0.75	0.021	
	Tilje	0.5	51-75	12-25	20-50	15	900	0.660		1.24	0.020	
	Are	0.1	60-71			9	922	0.660		2.29	0.020	
Oseberg	Brent	0.1-1	60-89	27	10	8	850	0.680	728	0.43	0.023	-
Smorb.	Garn		76	-	-		-	0.905	766	-		0.13
	Ile		57-75	-	-							-
	Tofte		64	-	-		-	0.926	771	-		0.12
	Tilje		61-84	-			774	0.946			0.090	
Smorb.-Sor	Garn	0.6	64-76	24			832	0.961	-	0.14	0.055	-
	Ile		60	25	20		-	0.992	768	-	0.052	
	Tilje-3		60	17	20		-	1.146	788	-		
	Tilje-2		55	17	20		820	1.100	-		0.070	-
Snorre	Statfj	0.3	86	17	10	6			-			

	L-DEF	0.25	76	22	-	10	690		-	0.42		
	L-BC	0.25	71	22	-	10	700		-	0.48		
Statfj.	Brent	0.5	84	30	-	13	824	0.771	-	0.31		-
	Statfj.	0.1	64	18	5	17	840	0.848	-	0.29	0.032	-
Statfj.-N	Volgian	0.3	83	35	-		842	0.844	-	0.74		-
	Brent	0.4	80	35	-		846	1.154	-	0.71		-
Ula	Ula	0.15	82	30	-	0-15	689	1.293	-	0.37	0.015	-
Veslef.	Brent		72	30	-	10	840	0.950	-	0.43		-
	IDS		70	30	-	12	830	0.970	-	0.34		-
	Statfj.		76			10	838	0.838	-	0.17		-
Frigg	Frigg	0.001-1	91		-		835	0.581	797	4.83	0.021	
Heimdal	Heimdal	0.01-0.8	86.7	29	-	9		0.712	710		0.022	
Midgard	Garn	0.5	94	-	-		-	0.762		-	0.022	
	Ile	0.2-0.3	92	25	10		663	0.762		0.36	0.022	
	Tilje	0.01-0.1	76	-	-		-	0.762		-	0.022	
Sleip.-V	Hugin	0.4-0.5	-	-	-	10		0.84	649	-	0.047	-
Sleip.-ø	Heimdal	0.1	-	-	-	5-10	-	1.456	653	-	0.009	1.2
Snohvit	Sto	0.10	93		-		866	0.749	750	0.59	0.023	
	N-mela	0.10	93		-		866	0.749	750	0.59	0.023	
Troll	Sognefj.	0.25-0.9	30-95	20-40	20-60		900	0.610	750	1.60	0.002	-
Ekofisk	Ekofisk	0.025-.10	88	38-63		<1	838	0.700	-	0.13	0.040	-
	Tor	0.025-.10	82	38		<1	838	0.700	-	0.13	0.040	-
Eldf.-A	Ekofisk	0.005-0.1	80	25-40		<5	830	0.830	-	0.11	0.048	-
	Tor	0.005-0.1	85	25-40		<5	830	0.840	-	0.11	0.049	
Eldf.-B	Ekofisk	0.10	70	25-40		<5	842	0.880	-	0.10	0.061	-
	Tor	0.10	80	25-40		<5	842	0.880	-	0.10	0.061	-

Table 07 - C *Properties of Norwegian (North Sea) Sand Stone Reservoirs*

Field	*Group/ Form.*	p_b *bar*	p_d *bar*	R_S	C_L	B_o	B_g^{-1}	C_1 *%*	C_{2-4} *%*	C_{5-12} *%*	C_S *mg/l*	C_{Di} *mg/l*	*T* *°C*	*p* *bar*
Balder	Heimdal	155	-	53	-	1.15	120	33.9	5.9				77	177
Brage	Statfj.	90	-	60	-	1.22	-	20.1	17.5		50210	5400	98	244
	Fensfj.	168	-	93	-	1.29	164	36.5	17.5		41710	2700	87	215
Draugen	Rogn	59	-	52	-	1.19	-	16	23	60	37500	400	71	165
Gulf.	Brent	244	-	94	-	1.25	-	45.4	6.2	47.0	41300	1970	72	310
	Cook	217	-	116	-	1.41	-	43.6	12.9	42.1			80	319
	Statfj.	270	-	171	-	1.46	-	49.6	13.6	35.7			80	320
Gulf.-S	Brent	383	418	200	240	1.60	286	58	10	30	41200	1560	125	450
	Statfj.	386	463	200	310	1.60	278	56	12	29	38800	1210	125	470
	Lunde	381	-	180	-	1.60	-	58	10	31			129	510
Gyda	Farsund	207	-	327	-	1.69	-	34.3	25.4	37.7	273000	33000	154	595
Heidrun	Fangst	241	245	117	108	1.34	219	44.3	12.7	43.0	27000	Low	85	252
	Tilje	232	224	79	85	1.21	219	43.8	9.0	47			85	251
	Are	201		60		1.16	219	40.8	3.4	55.8	32000	Low	85	251
Oseberg	Brent	281	281	145	310	1.43	222	46.3	13.8	38.9	37800	1450	100	281
Smorb.	Garn	-	447	-		2.32	238	73	13.9	9.2			143	467
	Ile	-		-			246	74.2	14.2	7.7			155	476
	Tofte		382	-		2.32	238	70.8	16.5	8.5			150	473
	Tilje		410	440		2.53	231	66.9	16.8	11.6			152	474
Smorb.-Sor	Garn	362	-	433	-	2.48	-	56	17	14	50000		140	403
	Ile	-	386	1356		-	234	70	17	9	48000		140	414
	Tilje-3	-		1247		-	230						145	436
	Tilje-2	323	-	438	-		-	55	25	15	64350		145	436
Snorre	Statfj		-		-		-				34000	2000	90	383

	L-DEF	179	-	133	-	1.40	-	37	23	40			93	383
	L-BC	155	-	105	-	1.33	-	32	22	45	34000	2000	93	383
Statfj.	Brent	276	-	190	-	1.58	-	49	17.7	32.6	14800	540	92	383
	Statfj.	196	-	155	-	1.54	-	39.5	19.5	40.3	14000	1250	99	404
Statfj.-N	Volgian	131	-	93	-	1.30	-	27.6	21.1	30.0	22000	600	98	398
	Brent	109	-	66	-	1.24	-	23.5	19.5	30.4	22000	600	98	398
Ula	Ula	166	-	164	-	1.35	-	28.1	20.6	28.4	200000	34000	143	491
Veslef.	Brent	195	-	125	-	1.46	-	37.0	20.1	42.9	19800	250	122	321
	IDS	200	-	140	-	1.49	-	36.0	20.8	43.2	29500	990	128	346
	Statfj.	332		320	-	2.1		54.8	17.1	28.1	43727	1663	133	355
Frigg	Frigg			61	5	1.15	194	95.5	3.7	0.07	60000		61	198
Heimdal	Heimdal		210		156		211	86.3	10.3	3.4	60000		76	218
Midgard	Garn	-	251	-	190	-	214	82	13.5	3.0	87000		90	251
	Ile	251	251	159	190	1.48	214	82	13.5	3.0	87000		90	251
	Tilje	-	251	-	190	-	214	82	13.5	3.0	87000			
Sleip.-V	Hugin	-	356	-	360	1.54	271	70.8	15.2	4.1	70000		120	442
Sleip.-ø	Heimdal	-	235	1729	336	2.19	213	71.0	21.4	6.2	36986	2820	93	245
Snohvit	Sto	263	259	149	112	1.44	229	81.4	8.8	2.28	93000	5210	93	267
	N-mela	263	259	149	112	1.44	229	81.4	8.8	2.28	93000	5210	93	267
Troll	Sognefj.	158	158	62	33	1.18	151	36	7	40	50000		68	158
Ekofisk	Ekofisk	383	-	273	-	1.78	-	58	15	27	50000	4400	131	497
	Tor	383	-	273	-	1.78	-	58	15	27	75000	3300	131	497
Eldf.-A	Ekofisk	340	-	471	921	2.42	266	54.7	16.9	28.4	50000	850	126	472
	Tor			479	933	2.45	268						126	
Eldf.-B	Ekofisk	400		458	1113	2.29	270	63.3	14.1	22.6	47000	1050	126	476
	Tor		-	458	1113	2.29	270						-	-

Table 08 *Volumes of Norwegian (North Sea) Sand Stone Reservoirs*

Field	Group/ Form.	A km^2	V_b $M\,m^3$	N $M\,Sm^3$	$N\,R_{si}$ $G\,Sm^3$	G_{Fi} $G\,Sm^3$	R_{oil} $M\,Sm^3$	R_{gas} $G\,Sm^3$	R_{ngl} $M\,Sm^3$	Period years	Meth	N_P $M\,Sm^3$	G_P $G\,Sm^3$
Balder	Heimdal	30	310	131	7	0	35						
Brage	Statfj.	7.7	470										
	Fensfj.	47	1260	149.2	9.8	0	46.2	1.7	1	1994-2010	W		
Draugen	Rogn	60	956	155	14	0	68	3		1993-2010	W		
Gulf.	Brent	35	2777	438	41	0	190						
	Cook	15	789	71	11	0	15	16.5	2.3	1986-2006	W	54	3
	Statfj.	10	651	52	10	0	25						
Gulf.-S	Brent		6200										
	Statfj.	88	1220	80.9	15.1	77	22.3	56.1	3.0				
	Lunde												
Gyda	Farsund	20	1000	75	23	0	30.5	2.9	2.4	1990-2010	W	3	0.4
Heidrun	Fangst	30	1311	153	15.3	14.7	62.7						
	Tilje	22	2329	172	14.3	23.7	23.1	37.8		1995-2010	W		
	Are	14	1046	10	1		1.5						
Oseberg	Brent	115	7662	460.4	67.2	64.0	226	70	6	1988-2017	W G	44	
Smorb.	Garn		592										
	Ile	90	5794	80	125	125	20	65					
	Tofte		1534										
	Tilje		7589										
Smorb.-Sor	Garn		1200										
	Ile		1268	89.4	30.5	9.8	31	24					

	Tilje-3 Tilje-2		1618 601										
Snorre	Statfj L-DEF L-BC	30 50 30	2045 3730 3195	341	39.2	0	106	6.7	3.2	1992- 2011	W		
Statfj.	Brent Statfj.	80 35	6513 4964	795.5 295	152 48	 0	396.4 130	 59	 18	1979- 2009	W G	339	18
Statfj.-N	Volgian Brent	 13	157 280	 66.8	 5.1	 0	 30.9	 2.5		1994- 2015	W		
Ula	Ula	16	1800	130.7	15.8	0	69.2	4.7	3.5	1986- 2009	W	25	1.7
Veslef.	Brent IDS Statfj.	22 12	1097 278 229	92	12		36.4	3.1	1.3	1989- 2008	W	4	
Frigg	Frigg	104	5030	1.2		235	0.7	180		1977- 1995	P		173
Heimdal	Heimdal		1616	9.4		60	5.7	35.6		1985- 1997	P		18
Midgard	Garn Ile Tilje	53	3000				15	80					
Sleip.-V	Hugin	80	6972	0	0	189	27	135	9	1996- 2013	P		
Sleip.-Ø	Heimdal	59	1446	0	0	88	19	51	10	1993- 2002	P		
Snohvit	Sto N-mela	80	5850	65.2			6.5	76	5.7				
Troll	Sognefj.	710	60000	670	48	1812	41	1288	30	1996 – 20??	P		
Ekofisk	Ekofisk	49	8300							1971-	WGP	161	73

	Tor	49	4150	1080	304.4	0	320	154	14.9	2048	W		
Eldf.-A	Ekofisk	11	488										
	Tor	11	325	366	95	0	74.6	55.3	5.2	1979-2025	P	47	18
Eldf.-B	Ekofisk	8	577										
	Tor	8	691	366	95	0	74.6	55.3	5.2	1979-2025	P	47	18

5.4 Formations

In this section short description is given of the group and formations in the tables in order to qualify the average values of the parameters. Whenever reading or applying average values, the effect of reservoir heterogeneities, such as permeability contrasts and flow barriers, should be considered.

- Lunde Formation

The Lunde Formation consists of channel and sheet sandstones (fine to medium grained), deposited in braided and low sinuosity river systems. Associated with the sandstones are shales deposited in floodplains and in lacustrine basins. The shales can represent flow barriers. The flow communication is moderate to good in the lower parts of the formation, but variable in the upper parts. This is mainly due to increasing frequency of shale barriers.

- Statfjord Formation

The Statfjord Formation is stratigraphically divided into three units: Nansen, Eriksson, and Raude. The formations consist of interbedded sandstones, siltstones and shales. Eiriksson and Raude represent fluvial deposits, while Nansen is deposited in a shallow marine environment. The river systems in Eiriksson and Raude are partly braided and partly meandering with varying sinuosity. The Nansen unit has excellent reservoir characteristics. The horizontal permeability in Eiriksson and Raude is good, while the vertical flow capacity is to some extent limited by the shale layers. The shales can represent continuous pressure barriers over large area of fields. Some of the channel sandstones have excellent reservoir characteristics and thereby represent high permeable zones. Diagenesis is important throughout the formation and is partly destroying the good primary porosity. Carbonate cement with limited distribution can locally represent flow barriers.

- Cook Formation

The Cook Formation in the Dunlin Group is deposited in a shallow marine, tidally influenced environment. The reservoir units are heterolitic with interbedded finegrained sandstones, siltstones, and shales. This generally implies an overall low permeability, and the vertical permeability is supposed to be low. The reservoir characteristics are best in the uppermost parts of the formation. Shale beds, calcite cement and internal textures are strongly reducing the vertical permeability throughout the formation.

- Intra Dunlin Sand

The Intra Dunlin Sand belongs to the Lower Jurassic Dunlin Group, and comprises three coarsening upward sequences, where only the uppermost has reservoir quality. The geological model is uncertain; both with respect to deposition environment and sedimentological processes, but mapped geometry and lithological variations indicate an elongated rather than a sheet like sand body. The prevailing interpretation is a near shore sand ridge / sand wave, probably deposited by enforced tidal currents. The reservoir flow characteristics vary from fairly well, with permeabilities that may attain values of 3 D, to extremely poor, and seem to be in accordance with elongated geometry of the sand body.

- Brent Group

The Brent Group is stratigraphically divided into the following formations (from base): Broom, Rannoch, Etive, Ness, and Tarbert. In the Oseberg / Veslefrikk area, the Oseberg Formation is developed below the Rannoch Formation.

The Broom Formation is not regarded as very productive in the Viking Graben.

The Oseberg Formation represents a fan delta complex deposited at the edge of the Horda Platform into a marine environment. The fan delta complex predates the huge fluvial Brent Delta and is genetically not related to the Brent Delta. The Oseberg Formation consists of stacked coarse grained sandstones with excellent reservoir characteristics. In parts of the basin, the sand layers are alternated with marine shale. Some of these shales are continues and act as flow barriers. In parts of the formation, carbonate cemented horizons are frequent. Some of these horizons represent omission surfaces and are widely distributed over each fan. Other carbonate cemented layers have a more limited distribution, but still act as local barriers during production.

The Rannoch Formation is interpreted as the lower / middle part of a prograding delta front and consists of interbedded shales, siltstones and fine grained micaceous sandstones with increasing sand content and permeability upwards. In some areas, the formation is regarded as non-reservoir unit.

The Etive Formation represents the upper part of the delta front, consisting of sandstones with high permeabilities in the lower parts and increasing occurrence of siltstones and shale horizons in the upper parts. The most important problems in the Rannoch and Etive are related to "high permeable zones" (in Etive and partly in the upper parts of Rannoch), "semi-permeable layers" (in lower / middle parts of Rannoch) and "barriers" (coal / shales in the upper parts of Etive and calcite cemented zones in Rannoch).

The Ness Formation represents the fluvial parts of the delta with straight to low sinuous channels. In the northern part of the Viking Graben, the formation is influenced by shallow marine processes implying more continuous sand bodies. Production is complicated by zones with very good reservoir characteristics, interbedded with poor quality layers. The coal layers are mostly interpreted to be widely distributed and may therefore act as a barrier to flow. The horizontal communication is moderate to good, with reduced vertical communication.

The Tarbert Formation represents the final event of the Brent delta system and shows large variations in the different fields. The Tarbert Formation has in general a very high sand content, but some interbedded shale barriers distributed over large area are recognized. The formation has overall good reservoir characteristics. The vertical permeability contrasts are larger than the horizontal. The vertical flow capacity is limited by the coal and shale layers.

- Hugin Formation

The Hugin Formation is of early Bathonian to early Oxfordian age, representing a marine transgression over the underlying delta complex of the Sleipner Formation. The thickness and content of the Hugin Formation is highly dependent on the structural setting. The formation is dominated by coastal, near shore marine sandstones, with the depositional environment ranging from coastal marsh and back barrier, through barrier and offshore bars to offshore sand and mud sheets. The reservoir characteristics are generally good, but change depending upon type of deposition. The net / gross values vary between 80% and 95% for the most productive zones.

- Fensfjord Formation

The Fensfjord Formation consists of offshore siltstones and fine grained, well sorted, clean sandstones of lower shore face environment. A cyclisity of coarsening upwards sequences probably reflects a variation in depositional environment, from transitional / inner shelf to lower shore face, caused by relative sea level fluctuations.

Consequently, there are permeability contrasts vertically which have great influence on reservoir behavior, where as only gradual change are expected in the horizontal continuation of these laterally persistent sands.

- Sognafjord Formation

The Sognafjord Formation comprises, together with the underlying Middle Heather Formation, six depositional cycles controlled by minor sea level fluctuations during an overall transgressive period. Each cycle commences with a micaceous, poorly sorted upward coarsening pro-gradational sequence, and is terminated by a transgressive component including excellent reservoir sands. These are cleaner, have good sorting sands and good reservoir characteristics, with permeabilities ranging from 1 to 10 Darcy. The reservoir characteristics in the pro-gradational sequences are rather poor, with permeabilities in the order of 100 to 200 md. Laterally, continuous and extensive calcite cemented horizons are believed to occur related to the interfaces between most of the depositional cycles, and also related to the interfaces between some of the pro-gradational and transgressive components. It is expected that these horizons will act as effective barriers for fluid flow in Troll Reservoir.

- Volgian Sand (= Intra Draupne Sand)

The Volgian Sand is deposited as submarine fans. The association comprises an upper proximal part, consisting of nearly 100% sand with very good reservoir characteristics. The lower distal part of the fans consists of alternating sands and shale, where the shales can be widely distributed. Some carbonated intervals with limited lateral distribution are recognized in the sandstones.

- Ula Formation and The Farsund Formation

The Ula Formation and the Gyda sandstone member of the Farsund Formation were deposited in marine environment on a storm-dominated shallow marine shelf. The sandstones generally consist of several coarsening upwards units, representing either regressive events caused by relative sea level changes, or storm generated pro-gradational blanket sands.

The difference units can be correlated within most of the individual fields. Although almost the entire interval consists of sandstones, the reservoir quality varies from very good to extremely poor. This is due both to variation in grain size and clay content and diagenetic effects (i.e. quartz and carbonate cementation) caused by great burial depth.

- Heimdal Formation

The Heimdal Formation is of Paleocene age and comprises alternations of two dominating facies, massive sandstones and fining upward sequences of bouma divisions, respectively. The facies association defined by these two facies suggests a submarine fan depositional environment, with deposits representing both infill channels and supra-fan areas. The reservoir properties are good, in spite of zones of low permeability associated with argillaceous and clayey divisions of the bouma sequences. Sandstone permeabilities often exceed 1 Darcy. Concretions and discontinuous layers of carbonate cement occur, but do not affect the gas production in the Heimdal Field.

- Frigg Formation

The Frigg Formation of Eocene age is a part of a Paleocene-lower Eocene submarine fan complex. The lower part of the formation is mainly sandy, but also contains heterolitic facies and breccias with strong syn-sedimentary deformation due to rapid sedimentation related to turbid tic deposition.

The pay zone (Frigg Formation Upper Member) consists of clean, unconsolidated sandstones with good reservoir characteristics. Average permeabilities range from 0.9 to 3 Darcy. The sandstones are organized in amalgamated beds with locally strong erosional contacts, related to deposition by grain flows in the channelized, proximal part of a submarine fan.

Some shale layers also occur. These layers are local and have limited lateral extent. However, they cause relatively strong dynamic pressure barriers that locally and temporarily have prevented the rise of water level in the reservoirs during production.

- Bat Group

The Bat Group comprises four formations: Are (base), Tilje, Tofte, which is only recognized on the western part of the Halten Terrace, and Ror (top).

The Are formation is interpreted as a coastal plain to delta plain deposits with swamps and channels pass upwards into marginal marine facies. It consists of alternating sandstones and claystones interbedded with coals and coaly claystones. Especially in the lower part the claystones act as vertical and lateral barriers.

The Tilje Formation consists of very fine to coarse grained sandstones interbedded with shales and siltstones. A near shore marine to intertidal depositional environment is typical of the formation. The formation is divided into reservoir zones with significant variation in reservoir properties separated by shale barriers.

The Tofte Formation is interpreted as fan deltas and consists of moderately to poorly sort coarse grained sandstones. In the Smorbukk Field, the formation is part of the reservoir, with peermeabilities > 10 md.

The dominant lithology in The Ror Formation is mudstones. Towards the top, interbedded silty and sandy coarsening upwards sequences are common. The formation was deposited mainly below wave basis in open shelf environments. The formation acts as a barrier between the Tilje Formation and the Fangst Group.

- Fangst Group

The Ile Formation is interpreted to represent various tidal influenced delta or coastline settings. The formation consists of fine to medium and occasionally coarse grained sandstones interbedded with thinly laminated siltstone and shales. Mica rich intervals are common. The reservoir properties are generally good. Especially within the lower part barriers may locally reduce the possibility for vertical fluid flow.

The basal part of The Not Formation consists of claystones deposited in lagoons or sheltered bays. Towards the top, the formation consists of claystones which coarsen upwards into bioturbated fine grained sandstones. This part of the formation consists of pro-grading deltaic or coastal front sediments. Generally, the formation acts as a barrier between the Ile and Garn Formation.

The Garn Formation consists of medium to coarse grained, moderately to well sort sandstones. Mica rich zones are present, and the sandstone is occasionally carbonate cemented. The formation may represent pro-gradation of braided delta lobes. Delta top and delta front facies with active fluvial and wave influenced processes are recognized. The permeability is generally good (> 10 md).

- Rogn Formation

The Rogn Formation shows a coarsening upward sequence from siltstones and shales to sandstones which constitute the bulk of the unit. The sandstones are interpreted as shallow marine bar deposits. The permeability ranges from good (100-1000 md) in the lower part to very good (> 1 Darcy) in the upper part of the reservoir.

- STO Formation

The sands in the formation were deposited in pro-grading coastal regimes, and a variety of linear clastic coast lithofacies are represented. Moderately to well sorted and mineralogically mature sandstones are dominant. Thin units of shale and siltstone are clear markers. Phosphatic lag conglomerates occur in some wells, especially in upper parts of the unit.

- Nordmela Formation

The Nordmela Formation was deposited in tidal flat to flood plain environments. Individual sandstone sequences represent estuarine and tidal channels which dissected this low lying area. The formation consists of interbedded siltstones, sandstones, shales, and claystones with minor coals. Sandstones become more common towards the top.

- Shetland Group

The Shetland Group includes the formations of the former Chalk Group. The group consists of pelagic limestone (chalk) and calcareous shales. The main reservoirs are situated in the pure chalks in the upper part of the group (Tor and Ekofisk Formations). Sedimentologically the chalks can be separated into two main facies, the open marine pelagic chalk and reworked submarine chalk facies. Generally, the reworked chalk facies have the best reservoir characteristics. Superimposed on the primary reservoir characteristics diagenesis and fracturing play an important role for the porosity and permeability development in the chalk reservoirs. The overpressure is also an important factor in conserving the anomalously high porosity in the chalk.

- Tor Formation

Overall, the Tor Formation has the most extensive and productive reservoirs in the Shetland Group. The formation is characterized by very pure chalks. The depositional environment of the Tor Formation is a mixing of pelagic chalk and submarine debris flow and turbidities. In the upper part of the formation, mass flows are very frequent and create stacked submarine fans of highly porous chalk. Another typical feature is the development of syn-sedimentary faults creating small grabens filled with re-sedimented chalk, also highly porous. The porosity in the Tor Formation ranges from 20-40%, in extreme cases up to 50%. The matrix permeability, on the other hand, is low and typically between 2-4 md, but may be locally exceed 10 md. Effective permeability caused fracturing may reach 150 md.

- Ekofisk Formation

The deposition of pelagic chalk and mass flows continue into the Ekofisk Formation. In the lower part the sediments are more argillaceous and tight, and can act as a flow barrier between the Tor and Ekofisk Formations. The best reservoir zones in the Ekofisk Formation are situated in stacked mass flow deposits containing reworked material from the Tor Formation. In other parts, slumped chalk plays an important role to improve the reservoir quality. Even the pelagic chalks are an important reservoir facies in the Ekofisk Formation, but in this facies the permeability is generally low. The porosity range in the Ekofisk Formation is 18-45%, and the matrix permeability is not dramatically different from the values in the Tor Formation (0.5 – 10 md).

5.5 Observation

On the basis of the available parameters (especially clay volume), the fields which have the initial potential for magnetized water treatment are;

- ✓ Balder (Heimdal Formation),
- ✓ Draugen (Rogn Formation),
- ✓ Gulf (Brent Group, Cook Formation, & Statfjord Formation),
- ✓ Gulf (Brent Group, & Lunde Formation),
- ✓ Gyda (Farsund Formation),
- ✓ Heidrun (Tilje Formation),
- ✓ Snorre (L-DEF & L-BC),
- ✓ Statfjord (Brent Group & Statfjord Formation),
- ✓ Ula (Ula Formation),
- ✓ Sleip. –V (Hugin Formation),
- ✓ Veslef. (Brent, IDS, & Statfjord Formation)

Table 09 *Fields Suitable for Magnetize Water Injection*

Field	*Group/ Form.*	*V clay %*	*Period years*	*Meth*	*Remarks*
Balder	Heimdal	0-25			Highly suitable for magnetize water injection
Brage	Statfj. Fensfj.		1994-2010	W	Both formations are not suitable for magnetize water injection
Draugen	Rogn	<10	1993-2010	W	Not highly suitable for magnetize water injection
Gulf.	Brent Cook Statfj.	5-25 20-40 15	1986-2006	W	All three formations are suitable for magnetize water injection
Gulf.-S	Brent Statfj. Lunde	10 5 15			• Brent group & Lunde formation are suitable for magnetize water injection. • Statfjord formation are not suitable for magnetize water injection.
Gyda	Farsund	0-30	1990-2010	W	Suitable for magnetize water injection.
Heidrun	Fangst Tilje Are	0.8 15 9	1995-2010	W	• Tilje formation is suitable for magnetize water injection • Fangst & Are formations are not suitable for magnetize water injection
Oseberg	Brent	8	1988-2017	W G	Incase of Oseberg field, the Brent is not suitable for magnetize water injection.
Smorb.	Garn Ile Tofte Tilje				All four formations are suitable for magnetize water injection
Smorb.-Sor	Garn Ile Tilje-3				All four formations are suitable for magnetize water injection

	Tilje-2				
Snorre	Statfj L-DEF L-BC	6 10 10	1992-2011	W	• Statfjord formation is not suitable for magnetize water injection • L-DEF & L-BC are not highly suitable for magnetize water injection
Statfj.	Brent Statfj.	13 17	1979-2009	W G	• Brent group in this case is suitable for magnetize water injection • Statfjord formation is not suitable for magnetize water injection because of gas injection
Statfj.-N	Volgian Brent		1994-2015	W	Not suitable for magnetize water injection
Ula	Ula	0-15	1986-2009	W	Suitable for magnetize water injection
Veslef.	Brent IDS Statfj.	10 12 10	1989-2008	W	All three formations are suitable for magnetize water injection
Frigg	Frigg		1977-1995	P	Not suitable for magnetize water injection
Heimdal	Heimdal	9	1985-1997	P	Not suitable for magnetize water injection
Midgard	Garn Ile Tilje				Not suitable for magnetize water injection
Sleip.-V	Hugin	10	1996-2013	P	Not suitable for magnetize water injection
Sleip.-ø	Heimdal	5-10	1993-2002	P	Not suitable for magnetize water injection
Snohvit	Sto N-mela				Not suitable for magnetize water injection
Troll	Sognefj.		1996 – 20??	P	Not suitable for magnetize water injection
Ekofisk	Ekofisk	<1	1971-2048	WGP	Not suitable for magnetize water injection

	Tor	<1		W	
Eldf.-A	Ekofisk Tor	<5 <5	 1979-2025	 P	Not suitable for magnetize water injection
Eldf.-B	Ekofisk Tor	<5 <5	 1979-2025	 P	Not suitable for magnetize water injection

CHAPTER 06

COCLUSION

CHAPTER 06

CONCLUSION

- Clay minerals decrease the efficiency of displacement in an experimental system with about 40%.

- The filtration characteristics of clay containing porous medium can be regulated by a steady transverse magnetic field applied to fluids passing through the medium.

- By subjecting the fluid to a steady transverse magnetic field, it is possible to control the extent of clay mineral swelling.

- It has been established that the decrease of the displacement efficiency and the change of the filtration characteristics of the clay containing porous medium are mainly due to the presence of a ferromagnetic film on the surface of the clay minerals.

- On the basis of the results of Tatariya oil field; by using magnetize field we can increase 30% oil production, 33%intake capacity of injection wells, and can improve the damage of borehole zone.

- Magnetic treatment device working with permanent or electromagnets should be used in the sphere of oil recovery for coping with complications caused by emulsion formations caused by emulsion formation, salt precipitation and asphalt and paraffin precipitation.

- In case of Norwegian Offshore Fields;
  Balder (Heimdal Formation), Draugen (Rogn Formation), Gulf (Brent Group, Cook Formation, & Statfjord Formation), Gulf (Brent Group, & Lunde Formation), Gyda (Farsund Formation), Heidrun (Tilje Formation), Snorre (L-DEF & L-BC), Statfjord (Brent Group & Statfjord Formation), Ula (Ula Formation), Sleip. –V (Hugin Formation), and Veslef. (Brent, IDS, & Statfjord Formation) are suitable for magnetize water injection

REFERENCES

- ✓ Quantitative Analysais.
  Moscow, Visshaja Shcola, 256-257 pages. Babko, A.K. and Pjatnicki, 1962.
- ✓ Physical Properties of Rocks and Mineral Resources.
  Reference book of geophysics. Nedra, page 140-194. Dortman, H.B. 1976.
- ✓ The Filtration Research of Non-Homogenous System.
  Moscow Leningrad, 351 pages. Efros, D.A., 1963.
- ✓ Electro-Surface Effect of Dispersed Systems.
  Energy, Moscow, pages 34-47. Grigorov, O.N., 1972.
- ✓ A Method of Production of Hydrocarbons.
  Patent. DD240235 A_1 WP E 21B43/13.22.10.86. Heeg, W. and Gadziew, G., 1986.
- ✓ Theory of Drying.
  Energy, Moscow, 416 page. Lykov, A.B. 1950.
- ✓ Magnetism of Mud Soils.
  Nedra, Moscow, 192 page. Osipov, U.B., 1978
- ✓ Soil Mechanics is Engineering Practice.
  Mc Graw-Hill, New-York-London, 607 page. Terzaghi, K. and Peck P., 1948.
- ✓ Linked Water in the Mud Soils.
  MGU, Moscow, 176 page. Zalchevskaia, R.I., 1969.
- ✓ Geology of the Norwegian Oil and gas Field.
  A.M. Spencer, C.J. Campbell, S.H. Hanslien, P.H.H. Nelson, E. Nysther, and E.G. Ormaasen (eds.), Graham and Tortman, London (1987).
- ✓ A Revised Triassic and Jurassic Lithostratigraphic nomenclature for the Norwegian North Sea. J. Vollset and A.G. Dore (eds.), NPD-bulletin No. 3 , Norwegian Petroleum Directorate, Stavanger (1984).
- ✓ A Lithostratigraphic Scheme for the Mesozoic and Cenozoic Succession Offshore Mid and Northern Norway.
  A. Dalland, D. Worsley, and K. Ofstad (eds.), NPD-bulletin No. 4, Norwegian Petroleum Directorate, Stavanger (1988).
- ✓ Internet (Wikipedia, & SPE)