Selective Production Possibilities in Order to Stabilise the Crude oil Production in Oil Field Bockstedt

Master's Thesis

Tzoni T. Raykov

University Adviser:
Univ. - Prof. Dipl. - Ing. Dr. mont Ruthammer Gerhard

Industry Adviser:
Dipl. - Ing. Joachim Sommer, Wintershall AG

Affidavit

I declare in lieu of oath that I did this work by myself using only literature cited at the end of this thesis

Tzoni T. Raykov

Leoben, February 2008

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Abstract

Water production in the Oil&Gas industry is a very concerning issue. Every day more and more of the world's major oil fields, produce more water because of aquifer encroachment and widely applied waterflooding. It has been reported that at this stage the Oil&Gas industry has to deal with more water than with oil, which makes it to appear like a "water industry". World-wide, we produce an estimated 3 bbl's of water for each bbl of oil (~75 billion bbl of water/yr). In countries with mostly "mature" fields, the average is typically greater than 7 bbl water for each bbl oil. In countries with mostly new fields, the average may be less than 1 bbl water per bbl oil.

As oil field mature excessive water production can threaten the economic value of a well by increasing production costs and reducing recovery. The only way to protect reservoir assets is to identify problem well early and to locate the zones within those wells which are water sources.

To avoid this excess water production, different flow conformance - water shutoff techniques during the years have been developed – mechanical and chemical.

Within the years of oil production the water cut in the Bockstedt field in North Germany started to increase. With the increasing WC the crude oil production rate started to decrease.

The objective of this thesis was to select the best candidates for water shutoff treatments in order to decrease the water production and to increase the production of crude oil from the reservoir.

Kurzfassung

Exzessive Wasserproduktion stellt ein Problem für die Öl – und Gasindustrie dar. Die größten Erölfelder der Welt produzieren Tag für Tag mehr Wasser, entweder aufgrund von grundwasserführender Schichten (Grundwasserleiter) oder durch das weit verbreitete Wasserfluten. Weltweit werden pro Barrel Öl drei Barrel Wasser gefördert (rund 75 Mrd. bbl Wasser pro Jahr). Die Wasserförderung in Ländern mit sogenannten " Mature Fields " liegt im Durchschnitt bei über 7 bbl Wasser pro bbl Öl. Für neue Felder kann der Durchschnitt bei weniger als 1 bbl Wasser pro bbl Öl liegen.

Der hohe Verwässerungsgrad erhöht die Produktionskosten und verringert die Ausbeute. Um das zu verhindern müssen nicht nur die Sonden, welche zu exzessiver Wasserproduktion führen, sondern auch die für die Wasserproduktion verantwortlichen Gesteinsschichten früh identifiziert werden.

Es gibt verschiedene Möglichkeiten exzessive Wasserproduktion zu verhindern, hauptsächlich chemische und mechanische.

Als Folge des steigenden Verwässerungsgrad im Bockstedt Feld in Nord Deutschland begann die Ölproduktion zu sinken.

Ziel dieser Arbeit ist es geeignete Sonden für " Water shutoff " auszuwählen und dadurch die Wasserproduktion zu senken sowie die Ölproduktion zu erhöhen.

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1. Introduction

The objective of this thesis was to investigate an oil field in North Germany – Bockstedt, in order to select the best candidates for water shut off treatment. Also the water shut-off (WSO) mechanisms are discussed and appropriate techniques are recommended.

The oilfield Bockstedt is one of the oldest assets owned by Wintershall. The field is situated in Wintershall's Ridderade Concession and covers an area of roughly 10 km^2. It has been discovered in the early nineteen fifties, and production from the field started in 1960. Up today the cumulative production is 3.9 MM tonnes of oil (API gravity of 27.4), which would correspond to 60 % of the calculated Original Oil in Place (OIIP). It is not well understood, why the recovery factor is so high. The high Recovery Factor can be explained by the presence of undiscovered blocks in the reservoir, which may share production with the discovered ones. Another possibility may be the inaccurate production data, which can lead to such results.

The pay zone in this reservoir is the Obervalengin Sandstein. There are no barriers in between, that mean that water phase and the oil phase are communicating.

Thickness of the pay zone varies between 2 and 30 meters. The porosity of the reservoir is in the range of 20 – 27 %. The permeability is very good with an average value of 1000 mD. In some places the permeability rise to the value of 7000 mD. On Tab.1 the data is summarized.

Permeability	140 – 7000	mD
Porosity	20 – 27	%
Net Thickness	2 - 30	m
Area	10	km^2

Tab. 1 Geological Properties

The field is divided into compartments Fig. 1. These compartments are separated from each other by different faults. Some of the compartments are added together and count as one producing Block. That's why the field is divided into six big blocks. It is assumed that the six blocks do not communicate with each other.

Block 1/2/3 consist of the compartments 1 and 2. The wells still in production in this block are: Bo_31, Bo_33, Bo_35, Bo_36, Bo_37, Bo_39, Bo_45, Bo_47b, Bo_H3 and the injection well Bo_46a.

Block 9/10/69/64a consist of the compartments 9, 10, 69 and 64a. The wells producing from this block are: Bo_9, Bo_29, Bo_56, Bo_69 and the injection well Bo_56

Block 8/7 consist of the compartments 8 and 7. The wells, which are still in production, are Bo_62, Bo_68 and the two injection wells Bo_23 and Bo_H1a

Block 12 consist contains only compartment 12. Wells, which are producing from this block, are: Bo_28a and the injection well Bo_R1

Block 4 contains two producing wells Bo_59 and Bo_60 and one injection well Bo_51

Block 6 consists of compartment 6, but there are no producing wells at this moment.

From the structure map on Fig. 2 beside the geologic structures the position of the wells can be seen.

Block 1/2/3 is the biggest one with the most oil producing well. Also the OOIP in this compartment has the highest value - 3.34 Mio m^3**.**

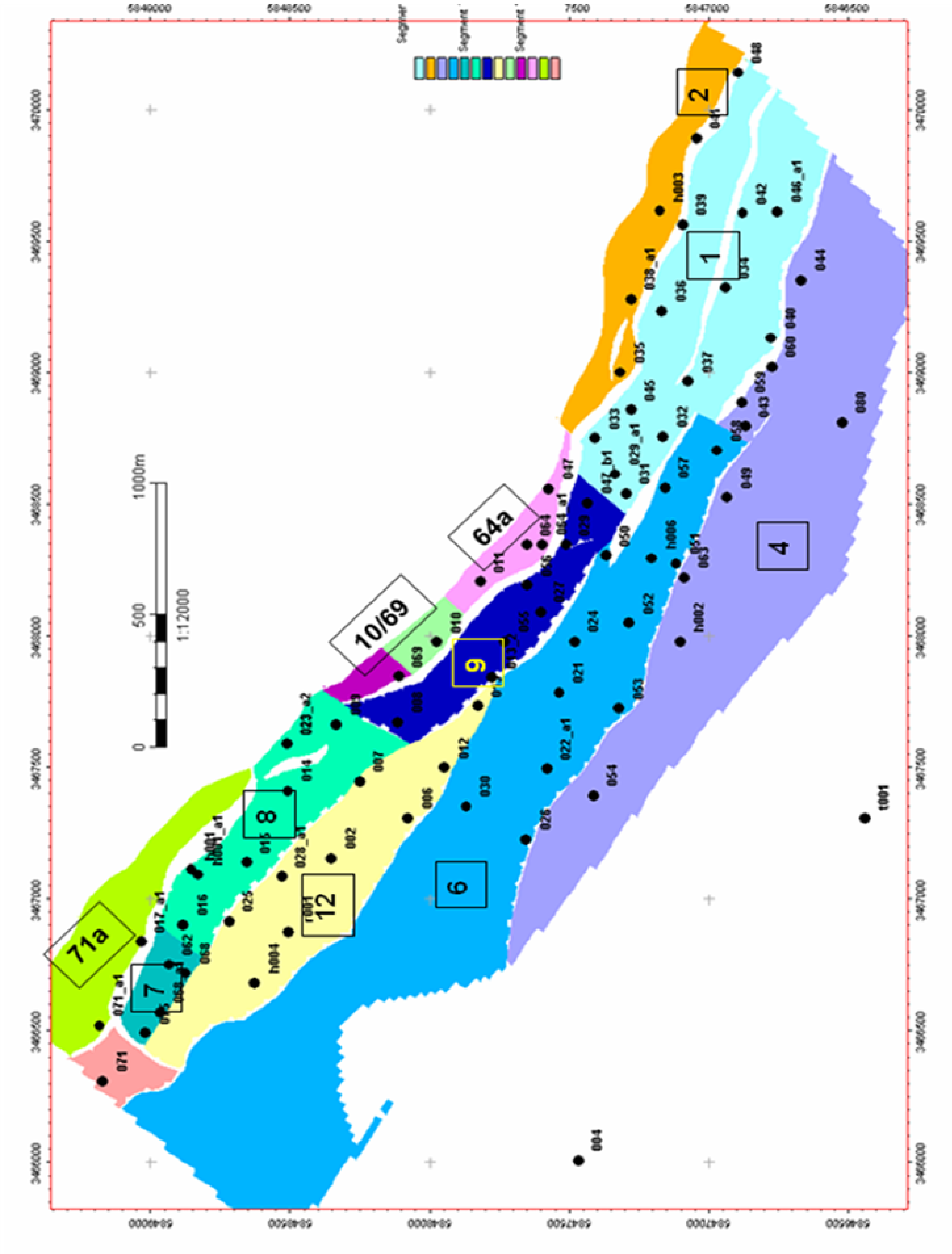

Fig. 1 Compartments in Bockstedt[23]

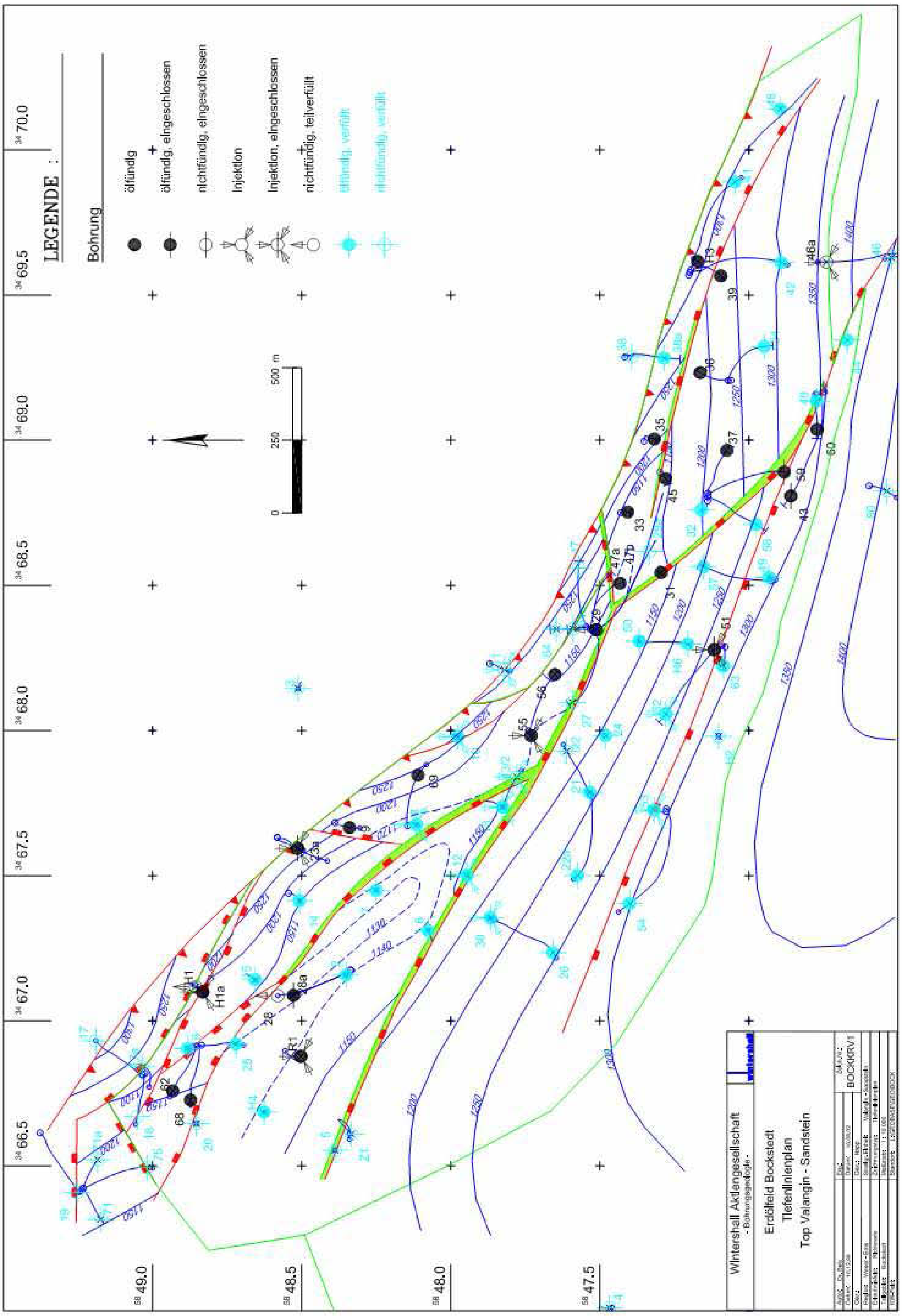

Fig.2 Structure map[27]

1.1 Pulse test

During production of the field, pulse tests were carried out in the reservoir. Pulse tests can confirm the existence of a connection through reservoir in between two wells. The tests are based on the following principle. An increase of injection rate (volume) in an injection well can or cannot be measured after a certain time with special measuring equipment in production wells in the surrounding area of the injection well. Whenever the emitted pulse is measured there is a certain connection between the injector well and the production well. This connection should have been established via the reservoir. By means of pulse tests an estimate of the permeability of this particular part of the reservoir can be made (through Darcy's Law). If no connection is confirmed by the pulse test, this can be caused by various reasons. Firstly, we can have such an attenuation of the emitted signal (e.g. caused by gas in the reservoir) that it is impossible to measure it with the equipment in the producing wells. Secondly there is the possibility of a permeability barrier like a fault or an impermeable body (or simply no reservoir existing) in between the wells. The confirmation of a connection in between wells can be used directly (see Figure 3).

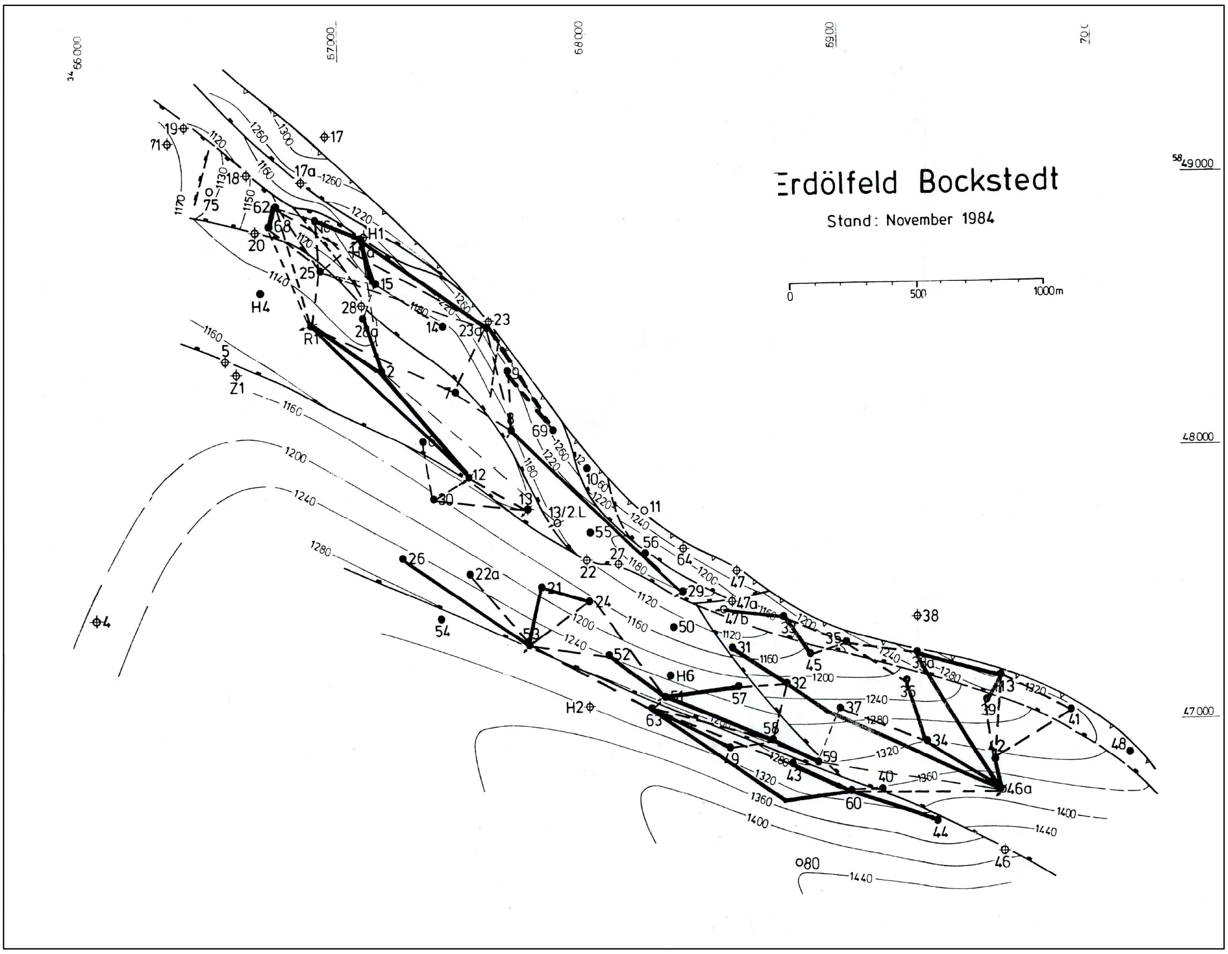

Fig 3. Pulse Test 1984[27]

The last tests carried out in the field are from year 1984.

The dotted lines on the Figure 3 are indicating that the connection between the wells is not proved. The black lines are indicating that the connection between the wells is proved.

1.2 Current Status of the field

As the field started to produce 80 wells were drilled. Today 70 from them are abandoned. Currently there are 17 producing wells in the field. The average crude oil production is approx. 71 m³/day (March 2007).

The drive mechanisms in the compartments 1/2/3 and 4/5 are the natural aquifer. In year 1962 well Bo_46 started to inject water in order to maintain the pressure in the compartment 1/2/3 and also to drive the oil toward the producing wells.

Water is injected in the field through six wells. Injection rates and position of the injectors are given bellow.

Well	Position (compartment)	Average Injection rate [m³/month]
BO_46	1	6,300
BO_51	6	4,900
BO_55	9	2,200
BO_R1	12	1,500
BO_H1	8	4,600
BO_23	8	800

Tab.2 Injection wells position and injection rate

Fig.4 Water cut for all wells in the field

As can be seen on Fig.4 the water cut in almost all of the wells in the field are above 96%. The high recovery factor linked to the increasing water cut of around 96% is indication that the field is in the depletion stage of its life.

1.3 PVT Data

In the Table below the reservoir properties and PVT data are listed

Based on viscosity and density two types of oil can be distinguished in the field. That's why the field is divided into a north and south part with dynamic viscosity of 22mPas and 12mPas for the south part. The north part includes the compartments 8/9, 7/12. 1/2/3, 4, and 6 belong to the south part of the field. The PVT data is coming from 2 wells (Bo_35 and Bo_2a)

Pay zone	Obervalangin Sandstein	
OOIP	7,19 10^6	m³
OWC – block 1/2/3	1360	m
OWC – block 4	1330	m
Reservoir Temperature	50	℃
Reservoir pressure - P_i	132	bar
Bubble point pressure	36	bar
Density @ 15℃	0,89	g/cm³
Oil Formation volume factor Bo	1,045	
Oil Formation volume factor at p_b - Bo_b	1,052	

Tab.3 PVT Properties

1.4 Wettability

Wettability is explained by the ease with which oil or water adheres to the surface of the rock. If production takes place in water – wet rocks it is easier and more efficient than in oil – wet rocks. The contact angle is used as a measure of wettability. If the contact angle is smaller than 90 degrees the fluid is treated as wetting, if the contact angle is larger than 90 degrees it is referred as non – wetting.

The wettability can be obtained by the relative permeability curves. On the figure below typical wetting and non – wetting fluid examples are shown.

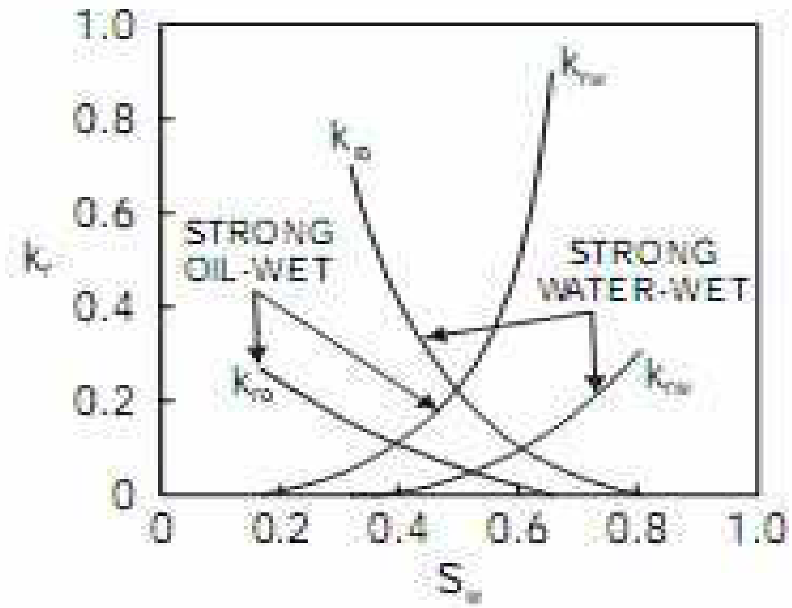

Fig. 5 Oil – water wet relative permeability curves[15]

Basically water wet system will exhibit a greater oil recovery under waterflooding, because oil moves easier in water wet rocks.

As can be see on Fig.5 the wettability affects the shape of the relative permeability curves. If having accurate data and the relative permeability curves are constructed the wettability of the system can be easily obtained. The type of wettability in the Bockstedt filed will be discussed in the next chapter, where the relative permeability curves will be plotted.

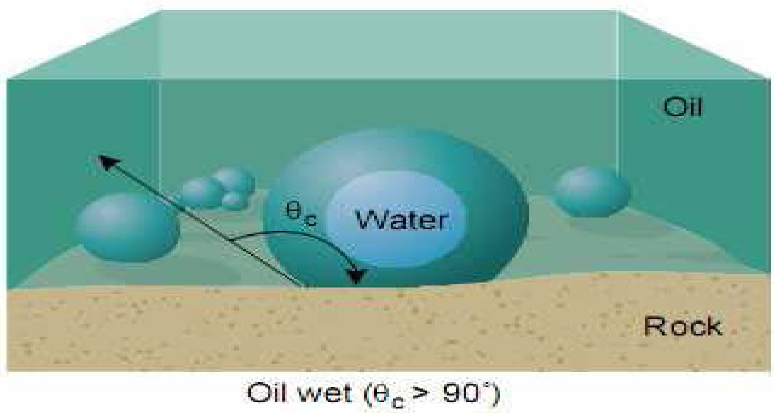

Fig. 6 Oil - Wet rock[12]

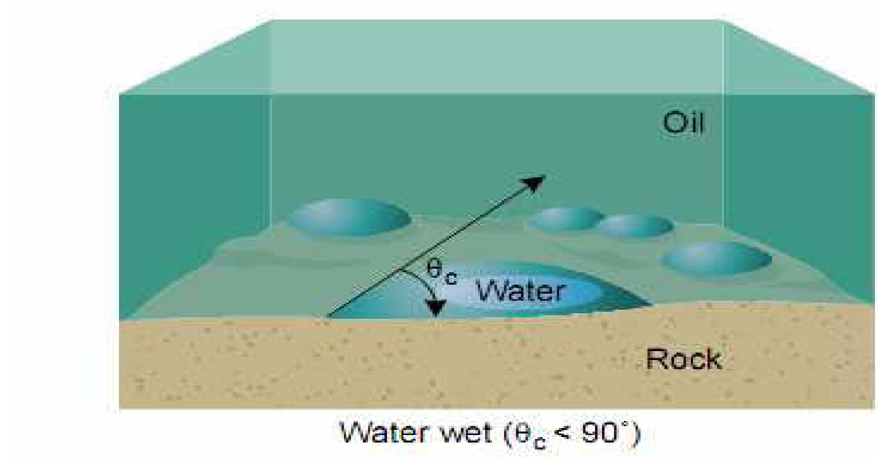

Fig.7 Water - wet rock[12]

2. Methodology

All workover and maintenance reports, which have been done in the Field, are put together in the Zechenbuch. From their reasons for the production changes were searched out.

Wellbore images for each well were made. They are showing the depth of the well, top and bottom depth of the payzone, perforation interval, and also completion type. This wellbore information was done, to get an overview of the producing wells. Also this images are showing, the accessibility of each well. Some wells are not accessible to their bottom, because of unsuccessful fishing jobs, or sand deposition within the well. This sand can be sucked out of the hole, but there are some problems associated with the performance of this job. While sand suction it is possible to damage the pay zone. That can happen if sand is also sucked out from the producing zone, leading to lower k*h value.

At the beginning of the work it was very important to understand the production trend in the field, and to detect the water flow paths. In order to do these Diagnostic plots in EXCEL were made (Fig.8). On this plots crude oil, wet oil and water production were plotted. This is a very good tool, allowing easily detection of problems in the field.

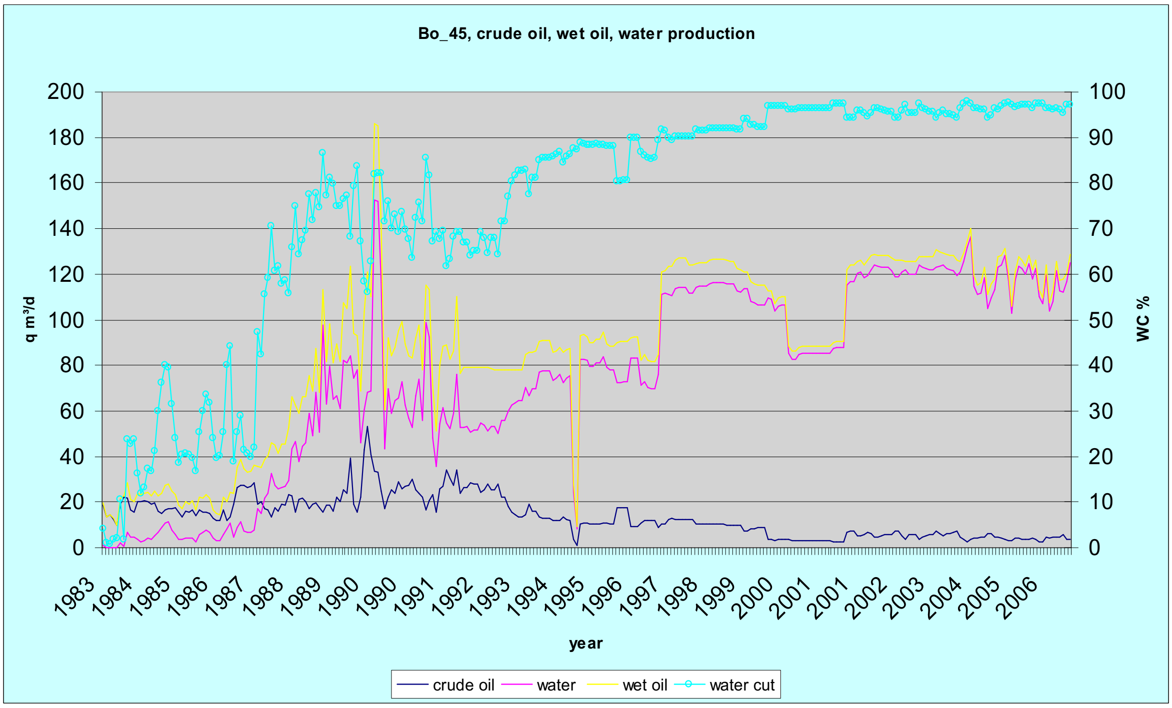

Fig. 8 Diagnostic Plots

After that the wells were divided into 2 groups, good wells, and bad wells. This assumption was made based on the increase in free water and decrease in crude oil production.

“Good wells” are those wells, where crude oil and water production is almost constant or water increases at a constant rate with time.

“Bad wells” are those wells, which water production increases very fast and the crude oil production decreases also fast. These are the wells, which are interesting in this project and need to be investigated further. Each increase and decrease in crude oil and water for this wells were noted and the reasons for this fluctuations were studied.

As mentioned before the average water cut in the field is above 96%. During the field history analysis, 2 wells in the field were found which produce with a WC 10% and 40 %. These are the wells Bo_31 and Bo_37. Booth of them are situated in block 1/2/3. On Fig. 9 and 10 the production profile of the wells can be seen.

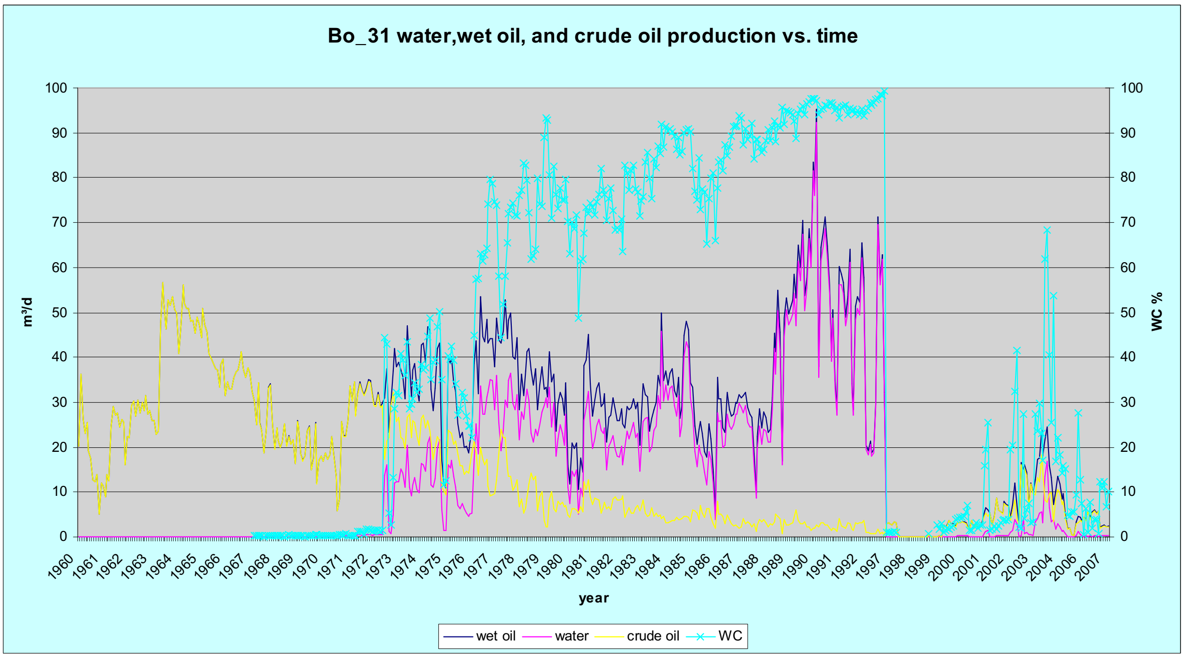

Fig.9 Production profile of well Bo_31

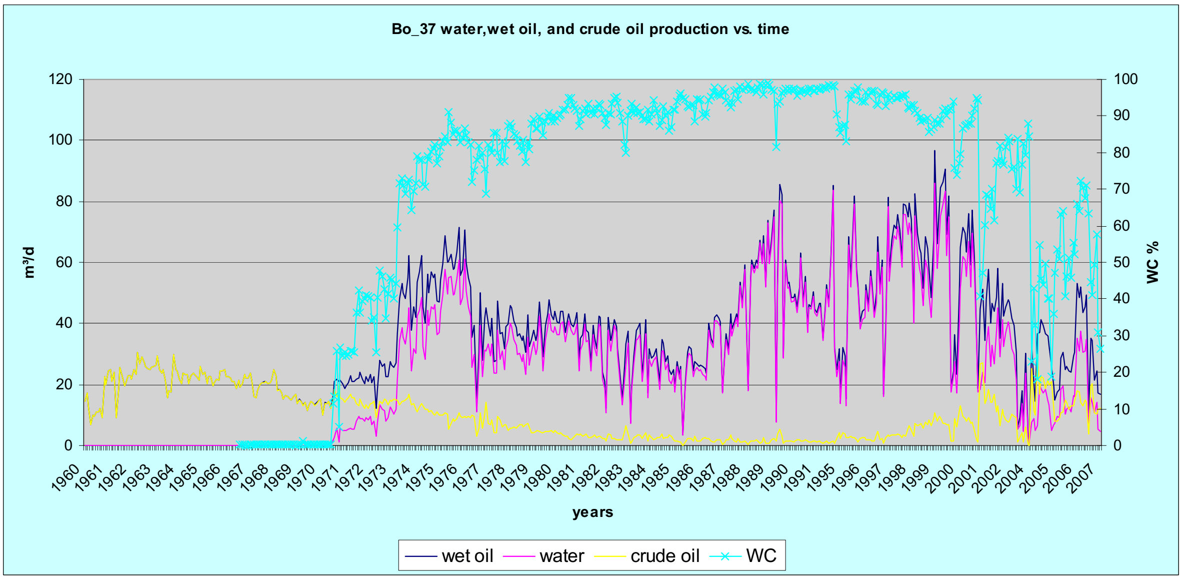

Fig.10 Production profile of well Bo_37

Production from Bo_31 started in year 1960. Until 1972 the well produced water free. Between 1972 and 1973 the water production increases up to 30 – 40%. That led to a decline in crude oil production. WC in 1998 was 99.3% and crude oil production was 0,8 m^3/d. Between 1998 and 2000 the well was shut in. In the years after that the crude oil production started to increase, and the water cut was fluctuating between 20% and 60%.

This drastic fluctuation in water production can be seen only at this well.

After year 2000 almost the same trend can be followed at well Bo_37. The water production started to decrease steadily, but it remains still above the crude oil production. After 2004 crude production overturned the water one. Today WC is 40% and crude oil production ranges between 10 – 12 m^3/d.

2.1 TDT Log[28]

Effective reservoir management relies on an accurate picture of oil and water saturations behind the casing. Saturation measurements track reservoir depletion over time and are crucial inputs for the development of workover and enhanced recovery studies and for the diagnosis of water related production problems such as injection-water breakthrough.

There are two ways to perform reservoir evaluation and monitor saturation through casing. The first measures the decay of thermal neutron populations and the other determines the relative proportions of carbon and oxygen in the formation using inelastic gamma ray spectrometry.

The salinity of formation water determines which of these methods is appropriate for any particular well. Chlorine, which is abundant in saline water, has a large neutron capture cross section, and its presence is readily established using the TDT (Thermal Decay Time) technique. However in wells where formation water salinity is low or unknown the carbon/oxygen method must be used, because the TDT data may be meaningless.

TDT - The Thermal Decay Time Log is a record of the rate of capture of thermal neutrons in a portion of formation after it is bombarded with a burst of 14-MeV neutrons. An electronic neutron generator in the tool produces pulses of neutrons, which spread into the borehole and formation.

The neutrons are quickly slowed down to thermal energies by successive collisions with atomic nuclei of elements in the surrounding media. The thermalized neutrons are gradually captured by elements within the neutron cloud, and, with each capture, gamma rays are emitted. The rate at which these neutrons are captured depends on the nuclear capture cross sections which are characteristic of the elements making up the formation and occupying its pore volume. The gamma rays of capture, which are emitted, are counted at one or more detectors in the sonde. During different time gates following the burst, and from these counts the rate of neutron decay is automatically computed. One of the results displayed is the thermal decay time, t, which is related to the macroscopic capture cross section of the formation, S, which is also displayed.

Because chlorine is by far the strongest neutron absorber of the common earth elements, the response of the tool is determined primarily by the chlorine present (as sodium chloride) in the formation water, like the resistivity log. Therefore, the measured response is sensitive to the salinity and amount of formation water present in the pore volume. The response is relatively unaffected by the usual Borehole and casing sizes encountered over pay zones. Consequently, when formation water salinity permits, Thermal Decay Time logging provides a means to recognize the presence of hydrocarbons in formations, which have been cased, and to detect changes in water saturation during the production life of the well. The TDT log is useful for the evaluation of oil wells, for diagnosing production problems, and for monitoring reservoir performance. TDT is a mark of Schlumberger.

Measurements for each well have been checked out. There was only one TDT measurement, made in year 1983, for the well Bo_45.Fig .11[27]

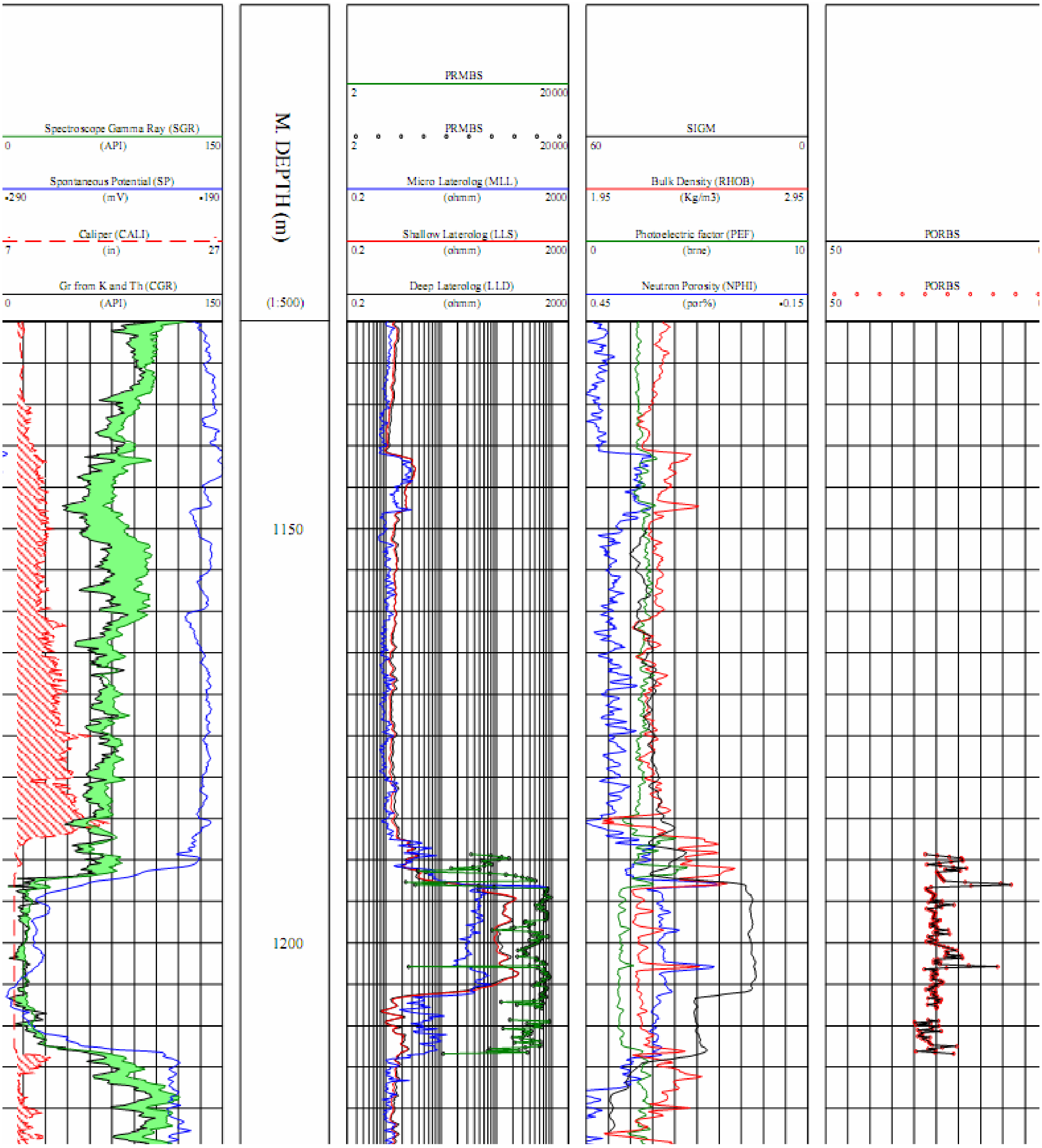

Fig. 11 TDT measurement Well Bo_45 – Yea 1983[27]

From this measurement can be clearly seen, where does the water moves within the pay zone. Also it can be seen, that there is only one layer without any barriers in-between. That means that the water and the oil phase are in contact.

To better understand the flow, the Dykstra – Parsons Method is used.

2.2 Dykstra – Parsons Method[15]

An early paper by Dykstra and Parsons presented a correlation between waterflood recovery and both mobility ratio and permeability distribution. This correlation was based on calculations applied to a layered linear model with no crossflow.

This first work on vertical stratification with inclusion of mobility ratios other than unity was presented in the work of Dykstra and Parsons who have developed an approach for handling stratified reservoirs, which allows calculating waterflood performance in multiayered systems. But their method requires the assumption that the saturation behind the flood front is uniform, i.e. only water moves behind the waterflood front.

There are other assumptions involved such as: linear flow, incompressible fluid, piston-like displacement, no cross flow, homogeneous layers, constant injection rate, and the Pressure drop (P) between injector and producer across all layers is the same.

The TDT measurement from 1983, divides the pay zone in well Bo_45 into 8 sections with different permeability, thickness and water saturation.

Based on this assumption, the Dykstra – Parsons Method was found to be suitable, to perform the calculation in order to evaluate through which one of the subdivided layers the water will flow faster (water breakthrough will occur earlier).

2.2.1 DATA SET

In order to proceed with calculations it is important to have accurate plug data.

For the calculation of vertical sweep efficiency, relative water permeability k_{rw} and relative oil permeability k_{ro} values are needed. The data used in this example is from the well Bo_45.This well is chosen in order to make comparison with the results from the TDT measurement for the same well. Well Bo_45 is situated in the west part compartment 1/2/3.

Six probes are available. Each one is for a depth interval within the pay zone. Permeability k, porosity PHI, water saturation S_w, krw and kro are given for each probe – depth interval.

This data is used to assign an average permeability for each layer of well Bo_45

- The permeability data is obtained from the core analysis
- The pay zone is divided into 8 individual layers based on the TDT measurement
- Water saturation Sw and layer thickness h are taken from the TDT Log from 1983
- The depth for each of the 8 layers are given in the Log report
- An average permeability is calculated for each depth interval and is assigned to the corresponding layer
- The layers are ordered according decreasing permeability

- Data for Sw, krw, and kro from six probes (for different depth) are available.
- The average permeability values for each one of the layers are added together and an average value is obtained (5445 mD).
- The resulting permeability is compared with the permeability obtained from the probe.
- There is an adjacent value of 5675 mD.
- Sw, krw, kro from that probe are used in the model (Probe Num. 70081d – Depth 1196, 4).

The relative permeability curves and the water saturation within each layer are calculated.

2.2.2 CALCULATIONS[15]

To be able to proceed with calculations, the distance from the injector Bo_46 to the production well Bo_45 was needed. It is approximately 800m.

Also the water viscosity was needed for the calculation of the fw. It was calculated following the Brill and Beggs correlations[11].

$$\mu_w = \exp(1{,}003 - 1{,}479 * 10^{-2} * T + 1{,}982 * 10^{-5} * T^2),$$

where T is in Fahrenheit and μ_w is in cp.

Following this correlation which is temperature dependent a value for μ_w was obtained μ_w =0,0006 Pas

The oil viscosity is taken from the PVT data μ_o=0,0108 Pas
The mobility ratio is calculated according the following formula

$$M = \frac{\lambda_w}{\lambda_o} \quad ,$$

The Oil mobility equals:

$$\lambda_o = \frac{k_{ro}}{\mu_o}$$

The water mobility equals:

$$\lambda_w = \frac{k_{rw}}{\mu_w}$$

The mobility ration equals:

$$M = \frac{k_{rw} / \mu_w}{k_{ro} / \mu_o}$$

From this equations mobility ratio of M=6,246 is calculated

$$q_o = - \frac{kk_{ro} A}{\mu_o}\left(\frac{\partial P_o}{\partial x} + \rho_o g \sin \alpha \right)$$
$$q_w = - \frac{kk_{rw} A}{\mu_w}\left(\frac{\partial P_w}{\partial x} + \rho_w g \sin \alpha \right)$$

and replace the water pressure by $P_w=P_o-P_{cow}$

$$q_w = - \frac{kk_{rw} A}{\mu_w}\left(\frac{\partial (P_w - P_{cow})}{\partial x} + \rho_w g \sin \alpha \right)$$

After rearranging, the equations may be written as:

$$- q_o \frac{\mu_o}{kk_{ro} A} = \frac{\partial P_o}{\partial x} + \rho_o g \sin \alpha$$

$$- q_w \frac{\mu_w}{kk_{rw} A} = \frac{\partial P_o}{\partial x} - \frac{\partial P_{cow}}{\partial x} + \rho_w g \sin \alpha$$

Subtracting the first equation from the second one, we get

$$-\frac{1}{kA}\left(q_w \frac{\mu_w}{k_{rw}} - q_o \frac{\mu_o}{k_{ro}} \right) = -\frac{\partial P_{cow}}{\partial x} + \Delta\rho g \sin \alpha$$

Substituting for

$$\mathrm{q} = \mathrm{q_w} + \mathrm{q_o}$$

and

$$f_w = \frac{q_w}{q},$$

and solving for the fraction of water flowing, we obtain the following expression for the fraction of water flowing:

$$f_w = \frac{1 + \frac{kk_{ro}A}{q\mu_o}\left(\frac{\partial P_{cow}}{\partial x} - \Delta\rho g \sin\alpha\right)}{1 + \frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}}$$

For the simplest case of horizontal flow, with negligible capillary pressure, the expression reduces to:

$$f_w = \frac{1}{1 + \frac{k_{ro}}{\mu_o}\frac{\mu_w}{k_{rw}}}$$

The plots for the relative permeability and the fractional flow curve are given bellow:

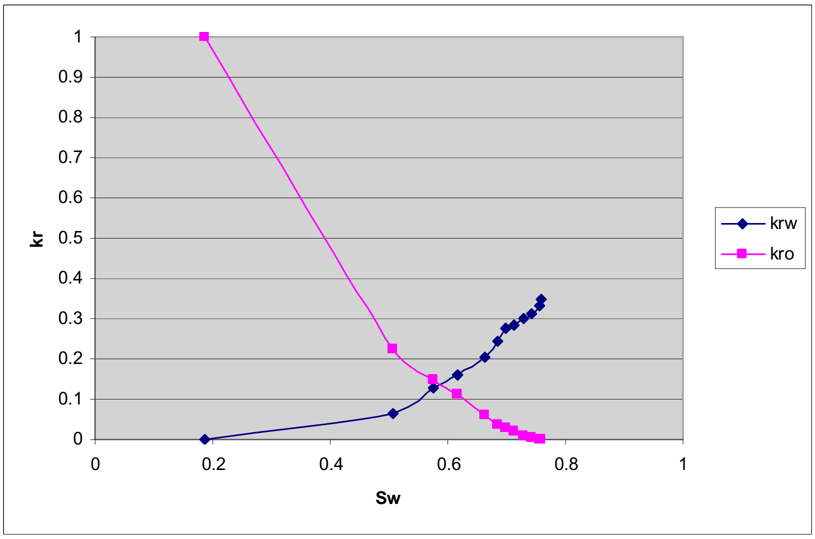

Fig. 12 Relative permeability curve Well Bo_45

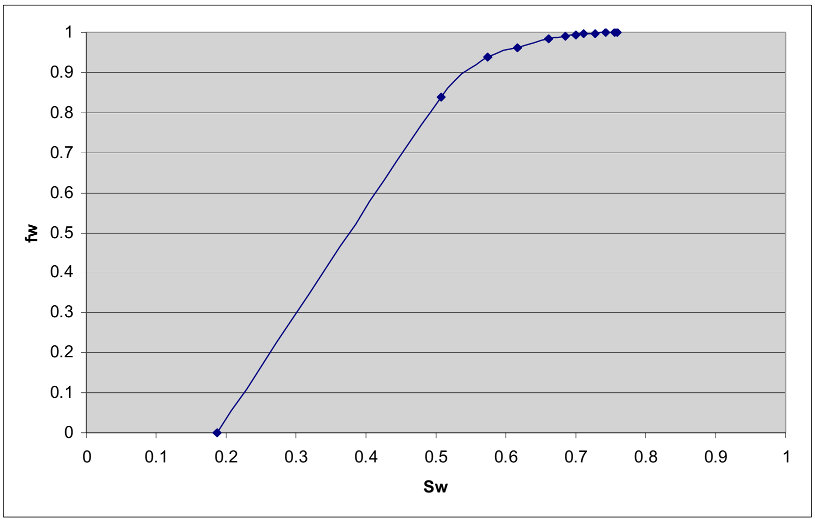

Fig.13 Fractional flow curve Bo_45

After this calculation was made, the time at which water breaks through each layer was calculated. The following formula was used:

$$t_j = \frac{L^2 * \phi(d)}{2 * \lambda_w * \Delta p * kj} * (1 + M)$$

The position of the front is given by:

$$(\frac{x}{L})_i = \frac{-M + \sqrt{M^2 + (1-M^2)\frac{ki}{kj}}}{1-M}$$

The total sweep efficiency of the n layers is given by

$$EI = \frac{1}{H}\left[\sum_{i=1}^{j} hi - \frac{M}{1-M}\sum_{i=j+1}^{n} hi - \frac{1}{M-1}\sum_{i=j+1}^{n} hi\sqrt{M^2 + (1-M^2)\frac{ki}{kj}}\right]$$

With the results obtained from the calculation it was possible to calculate the position of the water front and to plot it for each layer separately Fig.14.

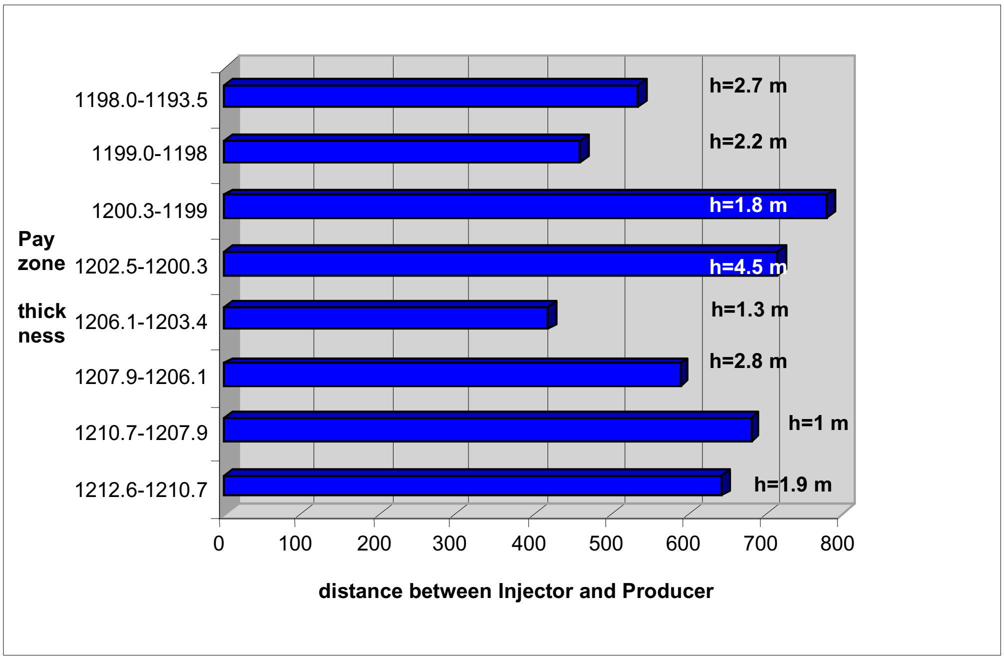

Fig.14 Results from DP showing the position of the front within each layer

2.3 Volume calculations

Before to precede with the calculation a short definition of how OOIP is calculated will be explained. The formula for the OOIP is:

$$N = \frac{V * \phi * (1 - S_{wi})}{B_{oi}},$$

N= OOIIP (barrels)

V_b = Bulk (rock) volume (acre-feet or cubic meters)

ϕ= Fluid-filled porosity of the rock (fraction)

S_w = Water saturation - water-filled portion of this porosity (fraction)

B_{oi} = Formation volume factor (dimensionless factor for the change in volume between reservoir and standard conditions at surface)

To able to calculate the exact amount of oil, bulk (BV) and pore (PV) volume must be known. Also the presence of initial water saturation is important.

The bulk volume is the whole volume of rock (V=a*b*c) and the pore volume is the volume within the rock, through which flow can occur. By dividing the pore volume through the bulk volume the porosity of the rock is obtained.

$$\phi = \frac{PoreVolume}{BulkVolume}$$

When some stimulation jobs are planned, they are performed for the sake of production improvement. In the case of oil production, it must be known from the beginning, which zones are good and have potential for further development.

In this project some simple material balance calculations were done, showing the production and the injection volume, from and into each compartment of the field. The data used for these calculations is taken from FINDA. FINDA is the production database of the company, where production data is stored. Calculations are very simple, but they present the volumes of crude oil which are still in the reservoir.

These calculations are done for each compartment separately and if some compartments are communicating, there in – out fluid volume is add together.

2.3.1 Compartment 1/2/3

Seventeen wells are drilled in Compartment 1/2/3. During the production life of the reservoir seven wells have been abandoned and nine are still in production, there is one injector well in the compartment. The volumes in this block are calculated separately for each sub-compartment. This is the biggest compartment in the field. It is directly connected to the aquifer.

Compartment 1 and 2 add together give up a Volume of OOIP= 3,343,999 m^3

2.3.2 Compartment 9/10

In this compartment seven well are drilled. Today only four wells are producing and there is one water injection well. There are two small compartments in the north part of this block. In the presentation “Bockstedt – Geological

Modeling" from Christian Derer they are named as Segment Well 69 and Segment Well 64. Both of them are taken into the volume calculation of compartment 9/10

The cumulative OOIP in this segment is the sum of the OOIP of each one of the sub segments. Results are presented in Table.7

2.3.3 Compartment 7

In this compartment only 2 producing wells are drilled. These are the wells Bo_68 and Bo_62.There is also the injection well Bo_H1a. Results from the calculations are given in Table. 6

2.3.4 Compartment 12

This block consists from one producing well and one injection well

	Compartment 1/2/3	
	Segment 1	**Segment 2**
Bulk V	13,798,807 m³	4,423,709 m³
Net V	13,798,807 m³	4,423,709 m³
Pore V	3,266,756 m³	1,046,658 m³
OOIP	2,535,503 m³	808,496 m³
Average Porosity	0,23	0,23

Tab. 5 Porosity, OOIP and Volume data Compartment 1/2/3

	Compartment 7	Compartment 12
Bulk V	1,040,029 m³	2,814,339 m³
Net V	1,040,029 m³	2,814,339 m³
Pore V	248,526 m³	697,666 m³
OOIP	180,000 m³	535,628 m³
Average Porosity	0,24	0,25

Tab. 6 Porosity, OOIP and Volume data Compartment 7 and 12

	Compartment 9/10			
	Segment 9	Segment 10	Segment Well 64	Segment Well 69
Bulk V	3,330,710 m³	905,151 m³	99.309 m³	623,938 m³
Net V	3,330,710 m³	905,151 m³	99.309 m³	623,938 m³
Pore V	824,798 m³	208,750 m³	25,770 m³	144,769 m³
OOIP	655,722 m³	159,793 m³	12,295 m³	144,293 m³
Average Porosity	0,25	0,23	0,25	0,23

Tab. 7 Porosity, OOIP and Volume data Compartment 9/10

On the table below the crude oil production and the water injection/production for the individual compartments can be seen.

	Compartment 1/2/3	Compartment 9/10	Compartment 7	Compartment 12
Crude oil produced	2,393,432 m³	409,073 m³	83,563 m³	201,309 m³
Water produced	//////////////////////	1,377,377 m³	341,857 m³	850,772 m³
Water injected	5,726,496 m³	446,255 m³	//////////////////////	1,201,240 m³
Remaining OIP	950,567 m³	540,927 m³	96,437 m³	540,000 m³
RF	71,57%	42,06%	46,42%	37,28%

Tab. 8 Recovery Factor, Water injected/produced and remaining OIP for all compartments

2.4 Pressure calculation

No pressure calculations in the field were done in the last 20 years. To be able to calculate the well flowing pressure P_{wf} and the Bottomhole pressure BHP, the data from the fluid level measurements were used. BHP and P_{wf} are needed in order to construct the IPR curve for the wells.

The wellbore is divided into 3 sections, as shown on the picture bellow.. For each section the hydrostatic pressure is calculated. There are some assumptions made, allowing simplifying the calculations.

It is assumed that the space between the top perforation and the intake of the pump (section number 1), is filed with oil - water mixture. The space above the pump intake till the liquid level (section number 2) is assumed to be filled with crude oil. And section number three is the space from the top of the well annulus to the fluid level. The pressure for this section is not calculated, because it can be read at the surface.

So we have three sections and each section has different pressure. Adding this 3 section together will give the well flowing pressure for the well.

When conducting a fluid level measurement, the well is stopped for a while in order to carry out the measurement. This short time period, do not allow significant build up in pressure. That's why the measured pressure is assumed to be the flowing one.

The static well pressure calculations are done for a time period, where the well was in rest for a long period. This non-producing time will allow pressure build up, until reaching the reservoir one. Because the BHP is needed in order to construct the IPR curve, it is very important to have accurate date to be able to conduct the calculation. Thata's why fluid level measurements for exact time periods are needed. These measurements are not conducted for the periods needed to construct the IPR curve. That can be seen on Fig.27, which is showing an unordinary IPR curve

In order to calculate the reservoir pressure a datum depth of 1260m is used. The pressure in each well is calculated at this datum depth, and so the reservoir pressure is obtained.

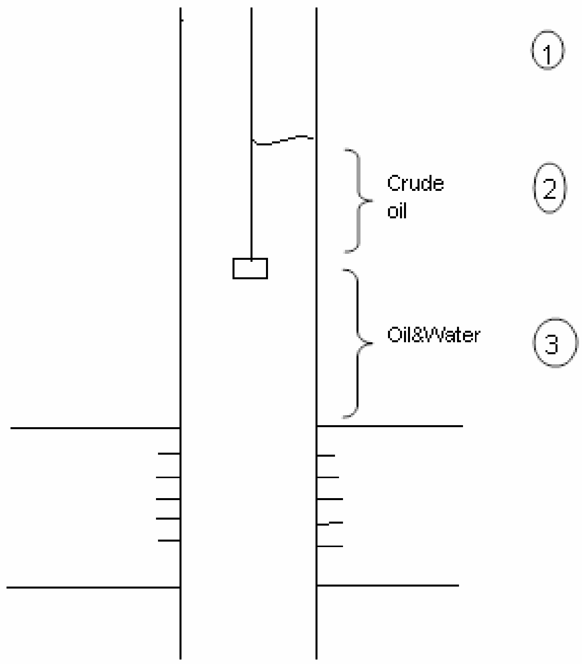

Fig 15 Allocation of each pressure zone

2.4.1 Calculation

As sad before, there are three different parts in the wellbore, for which pressure is calculated.

Part number 1

The pressure in this part is red on the surface, and after that written in the FL measurement report. So it doesn't need to be calculated.

Part number 2

This is the part between the intake of the pump and the fluid level in the annulus. It is assumed that this space is filled with crude oil. That's why in the calculation of the hydrostatic pressure in this column the density of the crude oil is used.

$$p_2 = \rho * g * h$$

Part number 3

In this column it is assumed that the fluid is a mixture of oil and water. If the well is producing above the bubble point pressure, than the presence of gas must be considered also. The formula used in this part is the same as in part two, only the density of the mixture is different.

The density is calculated on the basis of the water cut. Because the well is producing different amount of water, the density of the mixture in this part will diverse for the different periods of time.

For example:

WC	95	%
H_2O density	1127	kg/m³
Oil density	855	kg/m³
g	10	m/s²

Tab.9 Calculation example

The density for $WC_{95\%}$ will be calculated as fallows:

Density $_{(95\ \%\ WC)}$ = (WC_{95} x H_2O density / 100) +(1 – (WC_{95}/100)*oil density)

3. Water shutoff mechanisms

Basically by doing water shut of treatment the pressure drawdown (difference between the reservoir pressure and well flowing pressure) is increased by decreasing the well flowing pressure in the well. This means, that the productivity index of the well is increased, if the well after the treatment is producing the same quantity of fluid as before.

$$PI = \frac{Q}{p_r - p_{wf}}$$

Q – Production rate in m³/d
P_r – reservoir pressure in bar
P_{wf} – well flowing pressure bar
PI – Productivity Index

Assuming successful WSO treatment at having the same Q rate as before, will means that the crude oil production rate will be increased and the water quantity will be decreased.

Many different types of excess water production problems exist. Each problem type requires a different approach (e.g., different blocking agent properties) for optimum solution.

- **Cement, sand plugs, calcium carbonate**
- **Packers, bridge plugs, mechanical patches**
- **Pattern flow control**
- **In fill drilling/well abandonment**
- **Horizontal wells**
- **Gels**
- **Resins**

- **Foams, emulsions, particulates, precipitate, microorganisms**
- **Polymer floods**

Many different materials and methods can be used to attack excess water production problems. Generally, these methods can be categorized as chemical or mechanical.

Chemical & Physical Plugging Agents	Mechanical & Well Techniques
cement, sand, calcium carBonate	packers, bridge plugs, patches
gels, resins	well abandonment, infill drilling
foams, emulsions, particulates, precipitates, microorganisms	pattern flow control
polymer/mobility-control floods	horizontal wells

Tab. 10 Chemical and Mechanical methods for WSO

There are 3 fundamental questions in water control evaluation:

- How is water produced at the well?
- Can performance be improved by decreasing produced water volume?
- Is water control volume justified by field economics?

In order to achieve better results, the source of the water problem must be detected. Common water problems, ranging from the relatively simple to the complex one [22]

Category A: “Conventional” Treatments Normally Are an Effective Choice

1. Casing leaks without flow restrictions (medium to large holes).
2. Flow behind pipe without flow restrictions (no primary cement).
3. Unfractured wells (injectors or producers) with effective barriers to crossflow.

Category B: Treatments with Gelants Normally Are an Effective Choice

1. Casing leaks with flow restrictions (pinhole leaks).
2. Flow behind pipe with flow restrictions (narrow channels).
3. “Two-dimensional coning” through a hydraulic fracture from an aquifer.
4. Natural fracture system leading to an aquifer.

Category C: Treatments with Preformed Gels Are an Effective Choice

1. Faults or fractures crossing a deviated or horizontal well.
2. Single fracture causing channeling between wells.
3. Natural fracture system allowing channeling between wells.

Category D: Difficult Problems Where Gel Treatments Should Not Be Used

1. Three-dimensional coning.
2. Cusping.
3. Channeling through strata (no fractures), with crossflow

The first three listings are the easiest problems (Category A, Problems 1-3), and their successful treatment has generally been regarded as relatively straightforward. Of course, individual circumstances can be found within any of these problem types that are quite difficult to treat successfully. For example, for Problem Type 3, impermeable barriers may separate water and hydrocarbon zones. However, if many water and oil zones are intermingled within a short distance, it may not be practical to shut off water zones without simultaneously shutting off some oil zones. The ranking of water production problems in Table 1 is based on conceptual considerations and issues related to the ease of treating each type of problem[22].

Each of these problems requires a different approach to find the optimum solution. Therefore, to achieve a high success rate when treating water production problems, the nature of the problem must first be correctly identified.

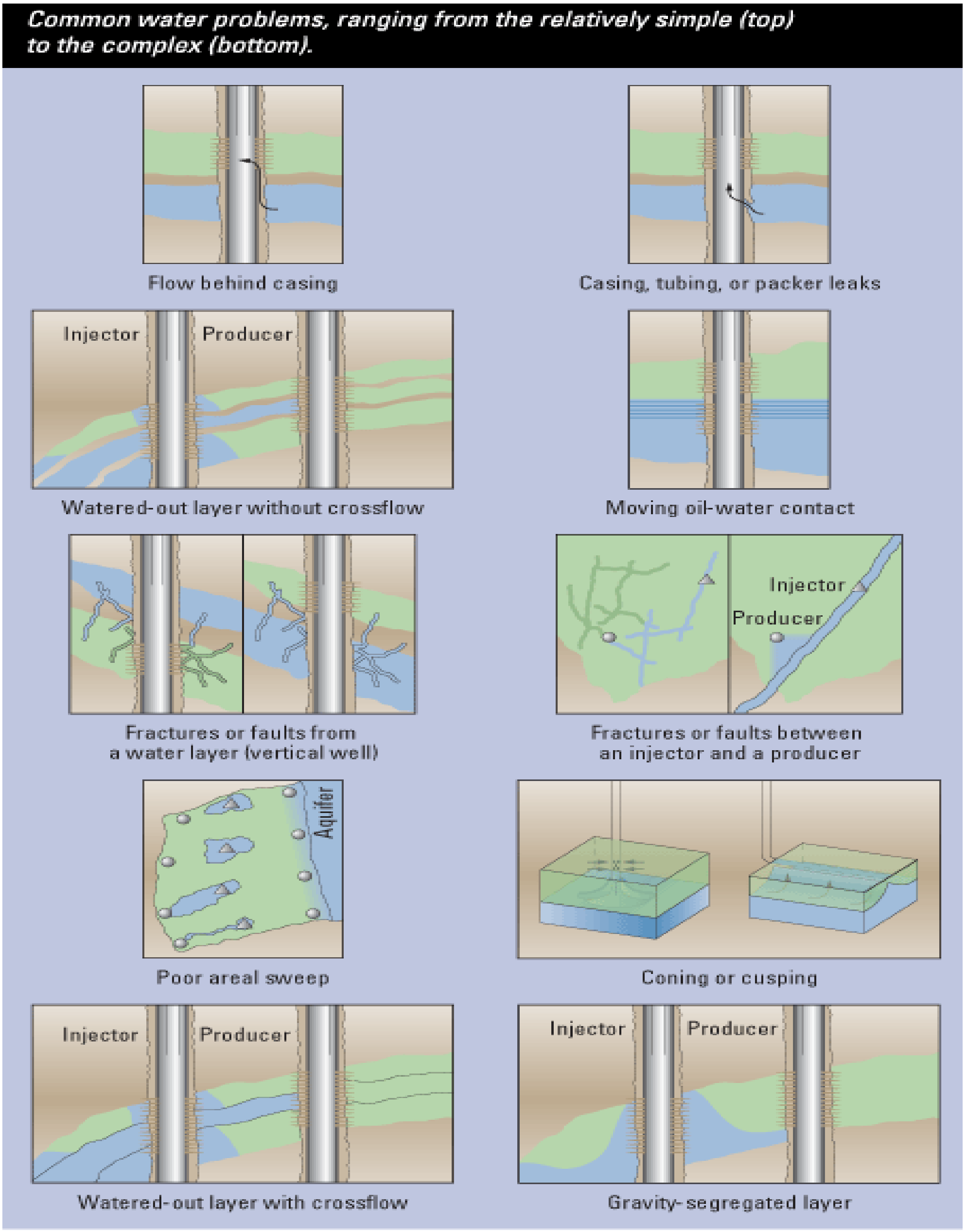

Fig.16 Common water problems[16]

As already mentioned, there are two basic types of water shut of techniques.

- Mechanical
- Chemical

There are a lot of limitations regarding the use of the chemical methods. Most of the operators are not familiar with the chemicals and the success rate by these methods is not so much compared to the mechanical treatments.

3.1 Chemical Treatments

In chapter one the main chemical and physical plugging agents used for water control are listed.

Chemical & Physical Plugging Agents
Cement, sand, Calcium Carbonate
Gels, resins
Polymer/mobility control floods
Foams, precipitates

Tab.11 Chemical and Physical Plugging Agents

According to their plugging mechanisms, chemicals can be divided into five types.

3.1.1 Inorganic salt chemicals

This type of chemicals consist of two kinds of chemical solution separated by seal fluid, after injected into formation, can form precipitant to plug the channels. Because these two kinds of chemicals solution are water solution with very low viscosity (near to the viscosity of water), which can selectively enter water entering interval and react to form plugging material in high permeability formation, such as, water glass (sodium silicate) can react with some gelling agent to form gel and plug the water channels in profile control interval. The gelling agent is acid or metal salt solution, which can form precipitant with water glass.

3.1.2 Polymer gel

The polymer gel plugs the water by physical plug with some absorption and dynamic entrapment.

The lots of reaction groups in polymer chain can react with crosslinking agents to form network structure, which forms visco – elastic gel by fixing the water in crustal constructure. By injecting the gel into the formation it plugs the porous medium and strops the water flow or changes the water flowing chanels. A lot of water shut off gel agents are developed, such as, polyacrylamide, polyacrylonitrile, lignin sulphonate.

Polymer – gel water shutoff treatments are highly reservoir -, well and problem specific. In order to successfully apply a polymer – gel WSO treatment, the underlying problem must be correctly identified and be amenable to polymer - gel WSO treatment. Than an appropriate polymer - gel system must be properly selected, sized and applied. Critical is to identify whether flow in the wellbore is radial (matrix flow) or liner (fractures), because flow regimes influence the required gel composition, V and placement method.

3.1.2.1 Relative Permeability Modification RPM / Disproportionate Permeability Reduction DPR[8]

The usage of this technique is very successful when properly designed. The problem is that there are a lot of limitations concerning the application of this technique.

First time application by inexperienced operator should be considered a somewhat high – risk undertaking.

In order to successfully treat unfractured production wells that are fully draw down, the oil and the water zone should not be in pressure communication and the oil-producing zone must be producing at 100% oil cut.

When these treatments are applicable they can be performed using bullhead injection – bullheading means to pump down the polymer gelants through the existing production tubing without any zonal isolation.

The goal of the treatment is to reduce the permeability to water to greater extent than to oil, by using water-soluble polymers and aqueous polymer gels

RPM/DPR water shutoff in single oil – producing zone is not applicable.

The mechanism of RPM implies that in the zone invaded by the gel water saturation increases, thus reducing the oil permeability. The magnitude of this reduction increases with the fraction of water produced from the zone invaded. Therefore, wells having near – wellbore ‘’virgin’ oil layers are good candidates. Old wells having produced for long periods of time at high water cuts are often bad candidates.

3.1.3 Foam

The foams are divided into two phases and three phase foam according to foam composition, the former consist the foamer and other additives, the later consist the foamer additives and solid phase such as bentonite, chalk and so on.

The three phases foam is much stable and wider application in oilfields than two phases foam.

The profile modification mechanism of three phases foam is that foam produce gas and liquid resistance effect-Jamin effect in formation and change permeable direction and water entering profile of water entry formation. Therefore, the swept area is increased, the water line moving rate on direction of main channels can be retarded, water absorption can be reduced and the swept volume and oil displacement efficiency of water flooding can be enhanced.

3.1.4 Resin

Resin include: phenol formaldehyde resin, epoxy resin, furfural resin and thermo plastic polymers, such as, polyethylene, polyvinyl acetate etc.

The resin diluted is injected into formation and consolidated at formation temperature by harden agent. The resin consolidated has very high hardness, can plug channels fully and life timely. The disadvantages of this method are high cost and low selection. It is difficult to remedy if the resin is injected into and plug the production zone. Therefore, this method is occasionally used to seal interporosity flow and lost circulation for high temperature formation.

3.1.5 Cement

Cement has been widely used for WSO all over the world for its low cost and excellent shut off ability. Cement is used successfully to shut off fractures, large pores, through casing or tubing.

The cement includes: water-base cement, oil-base cement, polymer cement and so on. The water-base cement is the oldest water plug material, sequentially, the oil – base cement is researched out which has selective plug action. The cement has high consolidation strength and low cost, but it is not preferable to inject it in deep into the formation.

3.2 Mechanical

The installation of mechanical isolation tool is not as complicated as the chemical treatments.

The most applied mechanical tools are:

- Bridge Plug
- Packer
- Patches

3.2.1 Bridge Plug

The Bridge plug is a downhole tool, which is set in the wellbore to isolate the lower part of it. Bridge plugs may be permanent and retrievable. They are designed in different sizes to be run and set in different casing and open hole sizes.

For long-term placement, it is recommended to utilize a permanent bridge plug with cement cap above it to ensure sealing and anchoring integrity of the plug.

For short term applications when a retrievable bridge plug is used, a Calcium Carbonate ($CaCo_3$) pill may be placed above the plug.

Both types of plugs can be set at coiled tubing or electric wireline.

The Bridge Plug holds differential pressure from either direction, as with all through – tubing tools. The tool is set, by pressurization of the work string. Continue pumping expands the inner bladder of the element until it becomes restricted by the ID in which it is set.

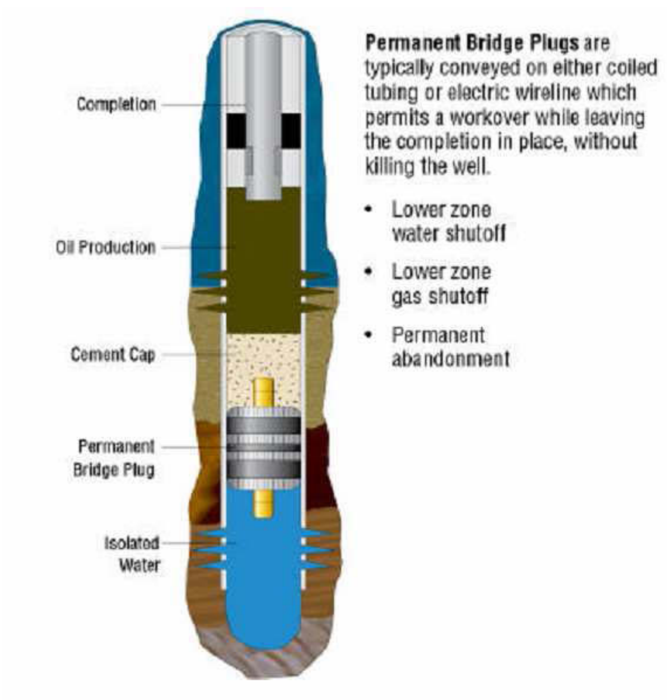

Fig. 17 Permanent Bridge Plug [9]

3.2.2 Packer

Packers can be also retrievable and permanent. Depending on what type of work is done in the well, the one or the other is chosen.

The retrievable packer is designed to provide isolation for chemical treatment jobs of either lower or upper zones. The packer can be run into the hole, on coiled or threaded tubing. To set the packer a predetermined amount of pressure must be applied on it. Once this amount is achieved, a ball seat is blown out the Bottom of the tool into the ball seat catcher. This provides the needed fluid flow path through the tool, into the zone of interest.

Once the job is completed, the packer can be equalized to avoid any potential kicking of the BHA. This can be achieved by straight pull or by dropping a ball to a sleeve in the running assembly.

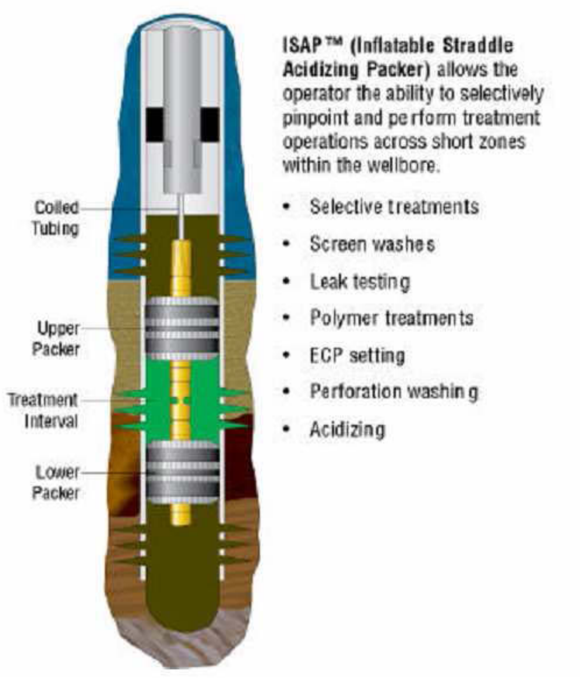

Fig.18 Inflatable Packer 1[9]

3.3.3 Patch

The patch is a downhole tools used in remedial repair of casing damage, corrosion or leaks. Patches are most frequently used as short-to medium-term repairs that enable production to be resumed until major workover operation.

Patches can be used in production wells, in wells that have to be deepened after patching and in disposal storage wells. They are permanent yet can be removed from the well Bore by milling

3.3.4 Permanent Cement Retainer

The cement retainer has been designed to be run on either coiled or threaded tubing. As with the retrievable packer the cement retainer is set hydraulically against a ball seat on the Bottom of the retainer. This permanent tool allow cement to be placed or squeezed through the workstring and into the formation below the tool.

A retrievable spotting valve which connects the running assembly to the retainer has been incorporated above the retainer to allow cement to be spotted to the tool, thus eliminating the need to pump unwanted fluids into the formation prior to cementing operation commencing. This is a good option, allowing leas damage to the formation. Once the cement is in place below the retainer, a spring loaded flapper valve on the Bottom of the tool mandrel is allowed to close locking in any squeeze pressure bellow the tool.

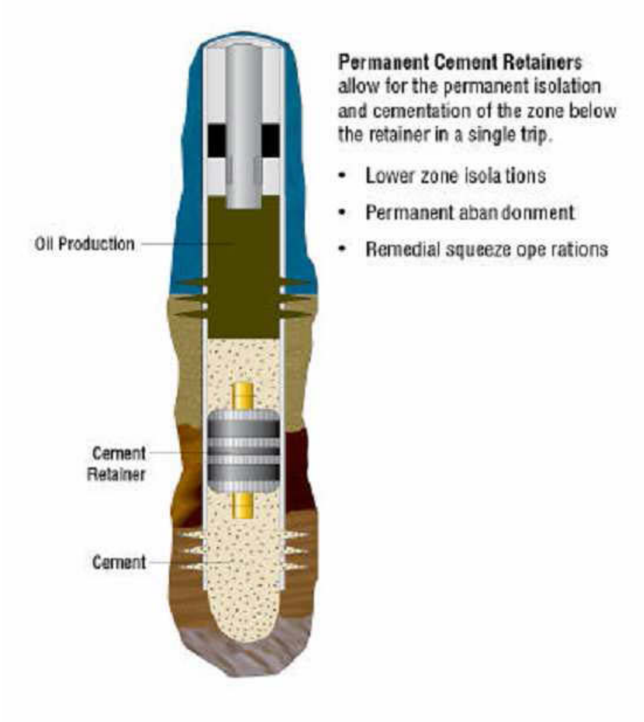

Fig.19 Permanent Cement Retainer[9]

3.3 Dual Injection [10]

Another possibility to perform the gelants placement is the so called DUAL INJECTION technique.

The goal of the dual injection is to improve the placement of gelant within the pay zone without to damage the oil producing zone. It is achieved by complete isolation of the water zone from the oil zone.

Two fluids are injected simultaneously into a well down through separate conduits. The fluids are:

- Protective fluid
- Gelant

The protective fluid can be diesel or water. The intent is to inject the treating fluid into the watered - out zone and the protective fluid into the oil zone without any cross flow between them.

To achieve this task a packer is run in a well and is placed between the two zone of interest. Gelant is injected down through the tubing into the watered out zone, and protective fluid through the annulus into the oil zone. Injection into each zone is controlled one of two ways. Either the individual injection rates are assigned based on the transmissibility and pressure of each zone, or the Bottom hole injection pressures of the two streams are balanced so that near wellbore crossflow between zones is eliminated. There are potential difficulties with either of these approaches. First the transmissibility and pressure of each zone are frequently unknown. Consequently, the assigned injection rate for gelant and protective fluid may be inappropriate. This could be disadvantage if crossflow between zones is high, and can lead to flow of gelant into the oil productive zone. Excessive rates of gelant and protective fluid can lead to hydraulic fracturing.

A dual injection system has been developed. It avoids some of the concerns mentioned above. The system consist of coiled tubing, an inflatable packer, and 12 ft. long 2-1/8 in OD sensor module. The sensor module consist of a gamma ray detector, casing collar locator, temperature gauge, and dual pressure gauge. All downhole data are transmitted up to the surface in real time via electric line run inside the coiled tubing.

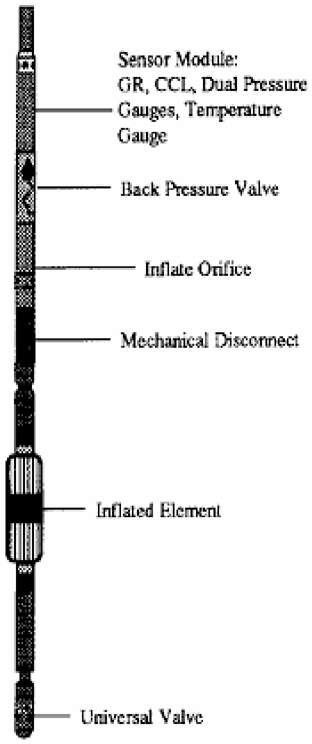

Fig. 20 Dual Injection Tool[10]

The two pressure gauges measure pressure upstream of the inflatable packer. One gauge is ported ti the inside of the coiled tubing and the other to the outside. With this configuration, pressures above the packer are directly measured by on of the pressure gauges. The other gauge can be used to determine the exact pressure below the packer if the pressure drop through the packer assembly is known.

This system allows several benefits. The combination of gamma – ray detector and casing collar locator ensures that the packer is correctly placed in the well. The temperature sensor measures actual downhole temperature during the treatment. This feature is very important for the polymer, because a polymer gelant vary with temperature. The dual pressure gauges can provide accurate pressure control, both above and bellow the packer. This is the critical issue conducting this kind of treatment.

When both the connectivity between intervals and zonal injectivity are high, dual injection should only be attempted if the layer properties are actually known, or if the fluid interfaces between the gelant and protective fluid can be accurately traced and regulated throughout the treatment. If at least one of these conditions is not satisfied, placement of the gelant protective fluid will be highly uncertain.[10]

4. Result and Discussion

Because in this field the most available data is from compartment 1/2/3, this study covers mostly this segment. In the other blocks no information were found, which can be helpful to investigate the compartments in detail. That's why based on the data, the Compartment 1/2/3 was studied into details.

First of all it is of great importance to understand exactly the flow path of the water.

Dykstra Parsons Method was used in order to be able to make comparison between the results from the Method and the results from the TDT measurement from well Bo_45. If there was a match in the water flow behavior, this method could be used for the other well, to predict there performance and water production.

The TDT measurement from well Bo_45 shows clearly, the movement of water in the vertical direction. It can be interpreted as movement of the water in this direction because of the high permeability in the field. From other side the results from DPM are showing the existence of high permeability channels within the reservoir, which are allowing the channeling of the water flow.

Assuming that this results and water behavior are true the same phenomenon must be found in the results from the TDT measurement. But the results from the measurement are showing completely different behavior.

Based on these findings it can be said that the TDT measurement is more accurate than results from the Dykstra Parsons Method (DPM). Some of the assumptions which are made, in order to be able to use the method are not fulfilled in our case. That's why it can be concluded that the TDT measurement is more reliable than the method itself.

The water movement in the reservoir can be explained by the high vertical permeability, which allows the free movement of the displacing fluid in vertical direction.

The relative permeability curves, which are obtained from the DPM are showing clearly that the reservoir is water wet. This data is reliable because it is from the plug data from the well Bo_45.

To be able to make some statements about the water flow path, the Injection Volume of injection well Bo_46 was plotted against time. Also included in this diagnostic plot are the water produced Volume of each well.

From there I come to the conclusion, that there are two water flow paths, one in N direction and one in SW direction. This explanation can be back up by the pulse test. Another explanation for the different flow paths may be the existence of undiscovered fault between the injector well Bo_46 and well Bo_37. If this is true, that can be the explanation for the low water cut in the well.

Another interesting well in the field is B0_31. The water cut today is between 10 – 15%.

During 1993 and 1996 two well close to that well were abandoned. Also Bo_31 did not produce between the ears 1998 and 2000. During that time a lot of fishing jobs were done – with low success rate. As can be seen in the (Appendix) the perforation interval is almost closed, because of sand participation and the tools, which are still in the hole. The non producing time, led to pressure builds up in the well.

Today the well is producing at intermittent production, and there is enough time for the segregation of the two phases.

Also the fluctuations in water production for the wells were studied. The periods where the wells have produced with lower WC have been searched out, and possible reasons for that were investigated. The data for this were taken from the Zechenbuch. It came out that these fluctuations were because of pump changes in the field (Fig.21, Fig.22, Fig23). Also the hot water treatments against paraffin deposition led to decrease in water production for a short time. After performing both of these operations, the WC has followed again its increasing trend.

Based on the results, basic requirements were written, which must be full field by the candidates, in order to perform successful water shut off treatment. The requirements are:

- ***Well producing at their economical limit (input energy vs. output)***
- ***Significant remaining OIP***
- ***Structural position***
- ***High WOR***
- ***High initial productivity***
- ***High producing fluid level***
- ***Perforation interval (length)***
- ***Thickness of the pay zone***

Well producing at their economical Level

By wells producing at their economical limit is meant, such wells which production is at their economical limit, because of high water production (high production costs) leading to high water treatment costs. Any whey there was no information about the economical performance of each well, but this is an important issue, which needs also to be considered before performing the job.

Significant reaming OIP

From the Volume calculations done in the field, can be seen that the block with the most remaining oil is the compartment 1 / 2.

This is also another reason, based on which wells from this compartment were chosen as potential candidates for WSO treatment.

Structural Position

This is also one of the most important requirements. Only wells which are high in structure are chosen. This is because of the results, from the TDT measurement, which is discussed before. In a mature field like this, which contains only one pay zone the lower part of the reservoir are flooded, it make no sense to concentrate on low structure positioned wells.

From compartment 1 /2 the wells, which can be attached to this point, are.

Bo_35
Bo_45
Bo_47ba

These wells are drilled in almost the highest part of the reservoir, which makes them good candidates based on these criteria.

High Initial productivity

In this point, such part and wells of the Compartment were investigated, which production was higher compared to others, and after that started to decrease, because of water invasion.

Here also the wells which fall into the requirement “Structural Position” can be counted.

High Producing Fluid Level

The Fluid Level is also a sign for the ability of the reservoir to deliver fluid into the well. If the wells are having inflow problems they are excluded

Perforation interval

The thickness of the pay zone and the perforation interval are connected to each other. Depending on where the well is perforated within the pay zone, the possibility of new perforations can be analysed.

High WOR

The high WOR is also a good tool to indicate WSO candidates. The difference between WC and WOR is that in the WC calculation the water rate is divided by the sum of the oil and water rates.

In WOR the water rate is only divided by the oil rate. This makes a big difference between Booth formulas.

Let's consider a well producing 4700 m³ of liquid per day.

q_o=200 m³/d and q_w =4500 m³/d

The WOR will be $\frac{q_w}{q_o}$=22,5

And the WC is $\frac{q_w}{q_o+q_w}$=0,0957=95,7 %

In the other way round if the q_o=250 m³/d and q_w=4450 m³/d

WOR = 17,8

WC = 94,6 %

By the usage of WOR instead of WC, a better representation of the water/oil rate is obtained.

As benchmark for the chose of appropriate candidate, the well Bo_33 was chosen. WSO treatment was performed at the beginning of 2007.

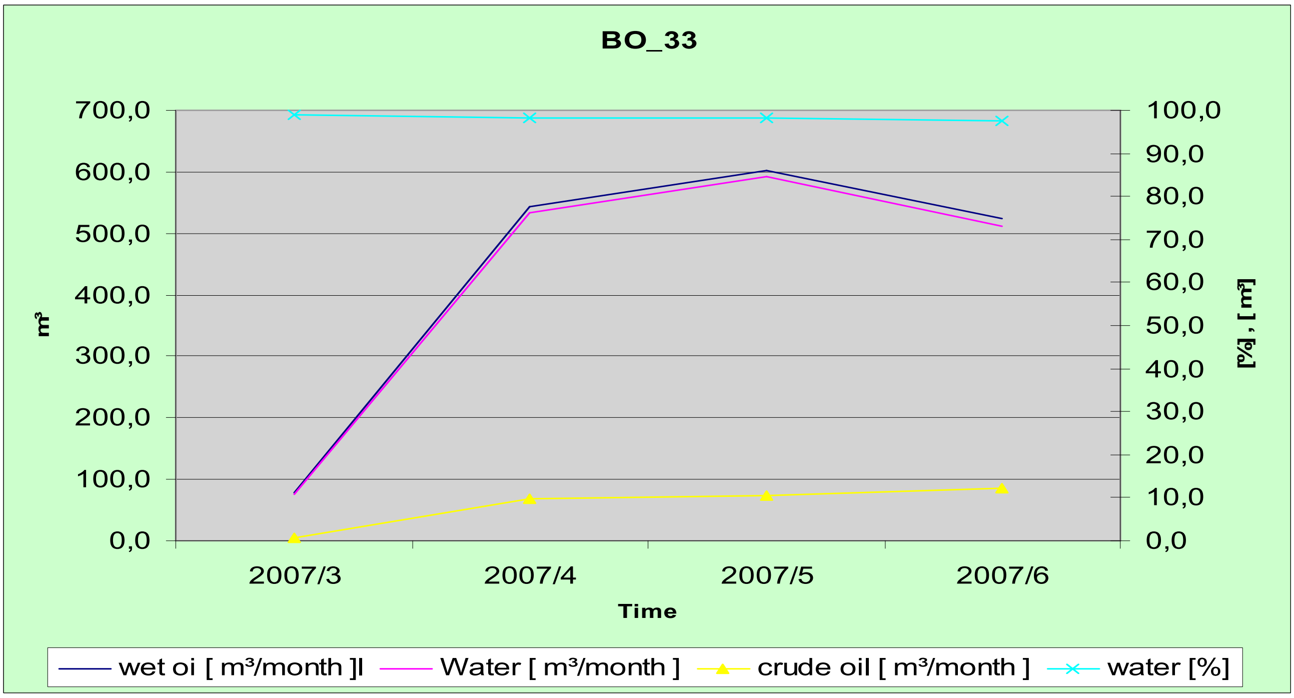

Fig.21 Bo_33 production development after WSO

Figure - 21 is showing the wet oil, water and crude oil production from March 2007 to June 2007. In March 2007 the water production was 99.1% and water shutoff treatment was performed. Bridge plug with cement cap was installed into the well and the crude oil production started to increase from the next month after the workover. After the treatment the crude oil production was increased with approximately 3 m³/month and the WC decreased to 97,6 %.

	Bo_33
Average FL above the pump	270 - 280
Average initial crude oil production m³/month	1150
WOR average	100
Structural Position Dept– casing shoe - m	1260
Perforation interval	1190 – 1211 21m
Thickness of the pay zone	1180 – 1211 31m

Tab.12 Bo_33

Based on the criteria mentioned above, 3 wells were found which fulfill the requirements. These are the wells Bo_35, Bo_45, and Bo_47b

	Bo_45	Bo_47b	Bo_35
WOR (03.2007)	35	28	22
WC	97%	96.57%	95%
Average initial crude oil production m³/month	500	400	700 - 900
Perforation interval	1193,5-1202 8,5m	1206,5 – 1210,5 4m	1259-1274 15m
Thickness of the pay zone	1192,5–1212,5 20 m	1199 – 1213 14 m	1259-1274,3 15,3
Structural position – depth of casing shoe	1250m	1263m	1308m

Tab. 13 Candidate data

The fluctuations in WC were also investigated. On Fig. 22, 23, 24 the reasons for that can be read off.

In order to construct the IPR curve, wellflowing pressure and reservoir pressure are needed. These pressures are calculated based on the data from the fluid level measurements. The data was not sufficient to conduct exact calculation of the static reservoir pressure but some assumptions were made in the sake of simplicity.

$$\frac{Q_o}{Q_{o,\max}} = 1 - 0.2 * (\frac{p_{wf}}{p_r}) - 0.8 * (\frac{p_{wf}}{p_r})^2$$

Only for two from the three candidates was possible to calculate the static reservoir pressure. As explained in Chapter 2.4 to perform a static pressure calculations, such liquid level measurements was used, which are done in periods, where the well have not been produced for a long period of time. However the measurements LL measurements done for the well Bo_47b do not coincide with the non producing time of the well.

That's why the IPR curve was constructed only for the well Bo_35 (Fig.28).

In Chapter 3 the different methods for WSO are discussed. The chemical methods are very promising, but their implementation is associated with high risk in such geological structure like Bockstedt.

The Dual Injection method is also very promising method. If this method would be chosen, the costs must be considered.

5. Conclusions and Recommendations

Basically it is assumed that there are no barriers in the reservoir, which makes the implementation of chemical WSO methods almost impossible.

On the TDT Log the existence of a barrier can be seen. It is not known till now how deep into the reservoir this barrier permeates. There is method which allows testing the pressure difference between the two zones above and below the packer. After the placement one of the zones is allowed to pressure up. If after that a pressure difference between the zones can be obtained the existence of barrier can be proved. If there is no difference in pressure, it can be concluded that there is no barrier.

It is recommended to do this in order to be able to investigate if this barrier exists or not. If this existence is proved the implementation of chemicals can be considered.

It is recommended to use the Through Tubing Bridge Plug as a WSO method. It is one of the easiest and most cost effective techniques being used in the company. To ensure increase in differential pressure a cement cap must be dumped above the plug.

As discussed in the previous chapter the well, which are chosen as candidates for WSO are: Bo_45, Bo_35, and Bo_47b. On Fig.25-27 the diagnostic plots of the wells showing production of oil [m^3/month] and WC [%] in vs. time can be seen

Anyway they must be ranked, from the best suitable to the leas one.

It was found that the well Bo_35 is the best candidate for WSO treatment. These conclusions were made base on the IPR curve (Fig.28), whish shows high potential in this well. After successful treatment the drawdown (difference between p_r and p_{wf}) will be increased by decreasing the p_{wf}, which will lead to increase in production. Another reason to choose this well as best candidate is the report "WIBENAK Rechnung 2006 for the Oil fields, Aldorf, Bockstedt and Düste "[3]. In this report the cumulative production of the wells vs. production cost are plotted, and well Bo_35 is marked as well with very high production costs.

In order to perform the WSO job successfully it is recommended to perform a TDT, RST measurement. This will allow identification of water saturated zones. Without performing this job, it will be difficult to set the bridge plug on the right position. When the OWC is obtained, the setting depth of the plug will be controlled by casing collar locator, which will be run with the wireline.

The second well in the ranking is Bo_45.
An the last is the well Bo_47b

The last production data from Bo_33, which is used in the project, is from 06/2007. The trend after the WSO treatment performed in this well is following increase in crude oil with 2-3 m^3 /month.

If the jobs are performed with TDT or RST measurement before setting the Bridge Plug the success rate for the new candidates may be much higher than Bo_33.

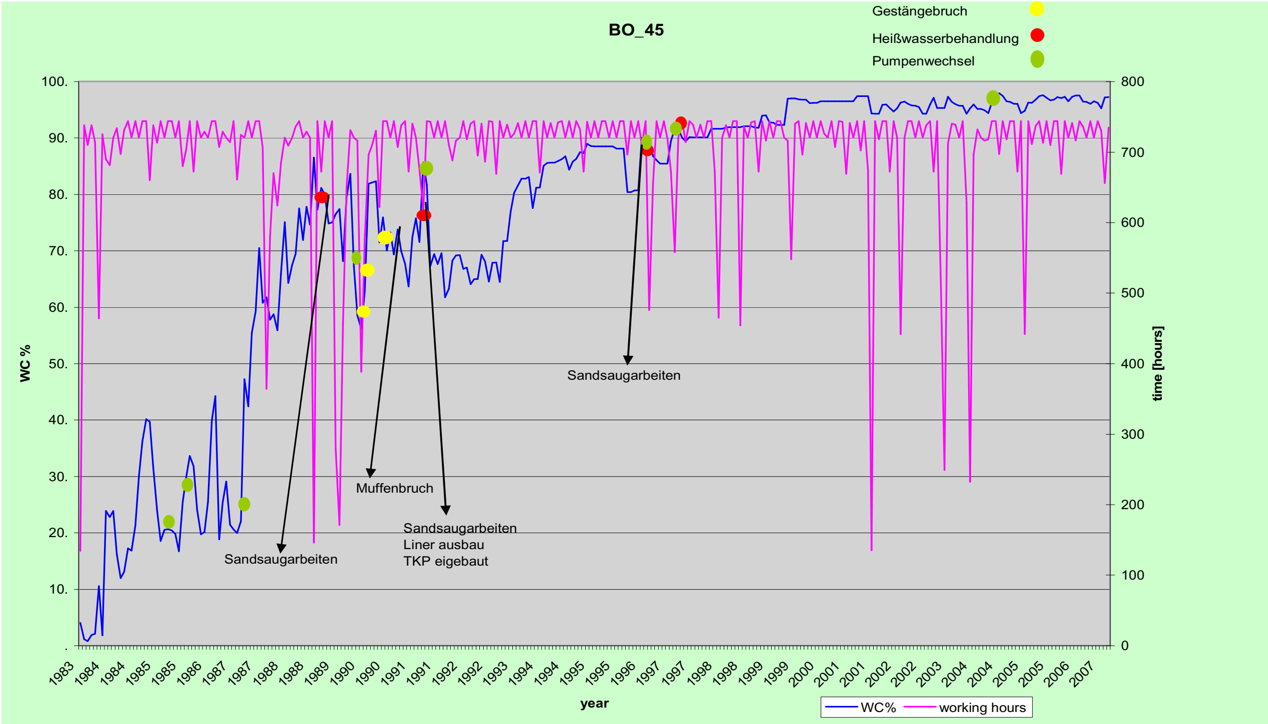

Fig.22 Diagnostic plot Bo_45

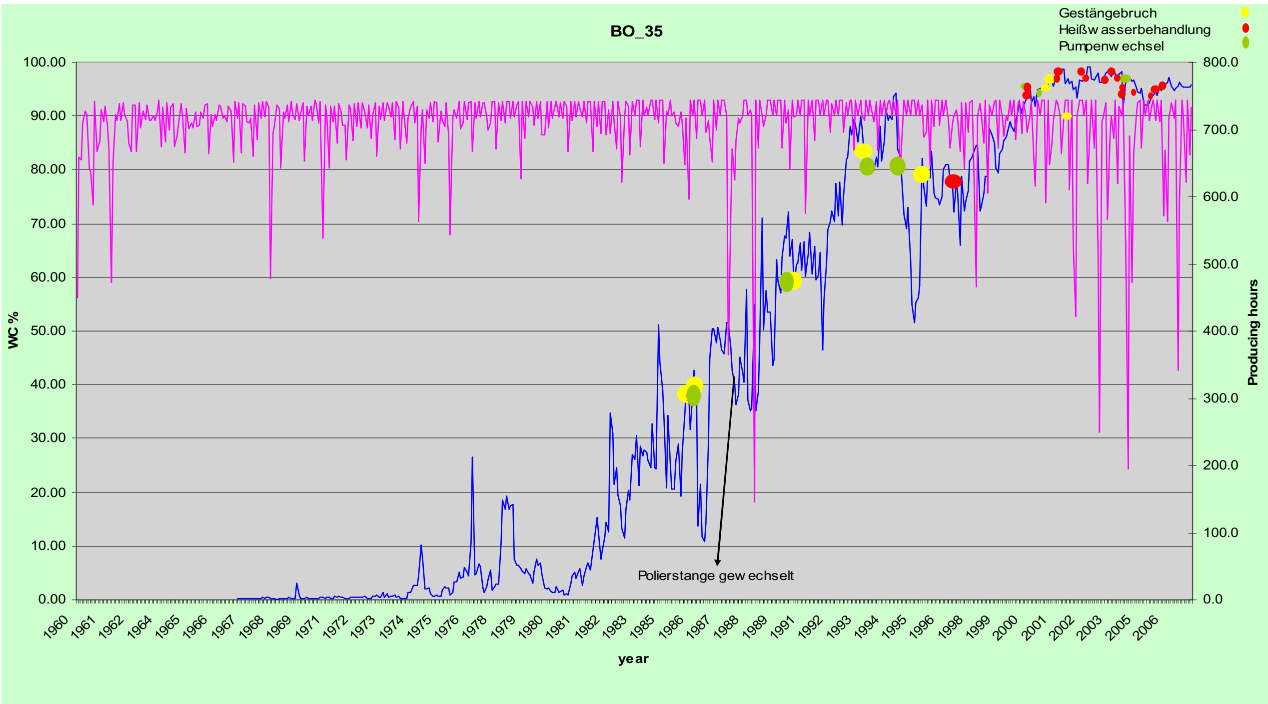

Fig.23 Diagnostic plot Bo_35

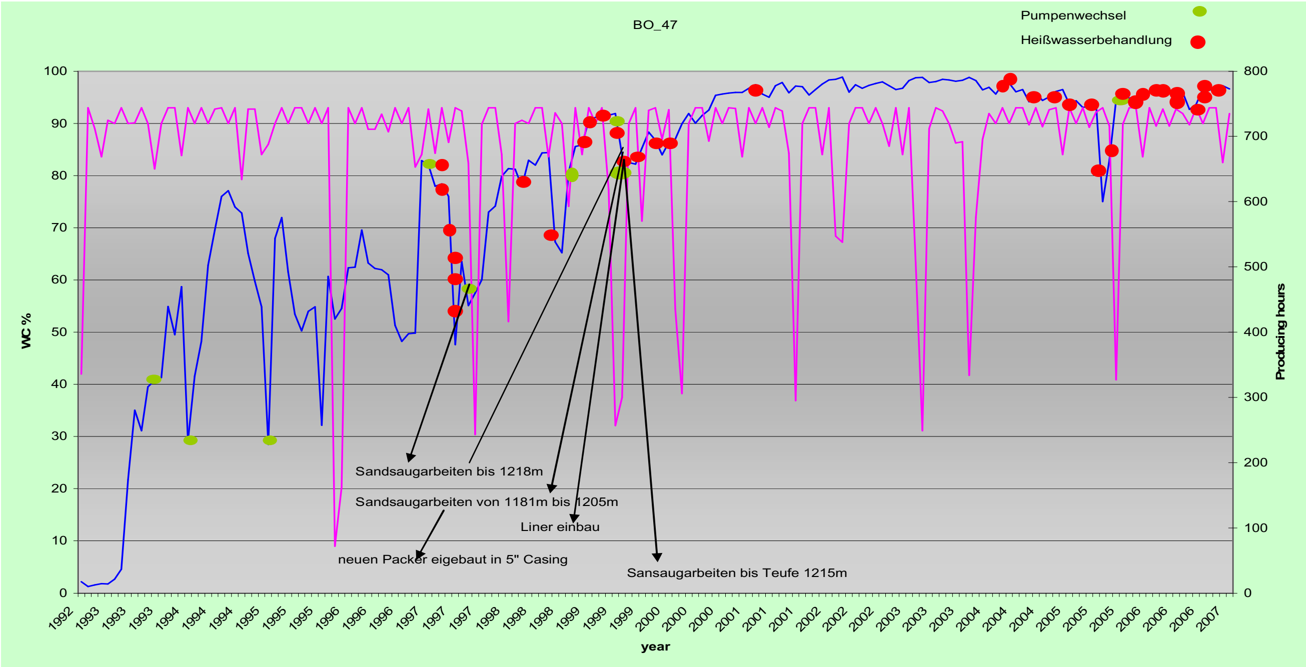

Fig.24 Diagnostic plot Bo_47

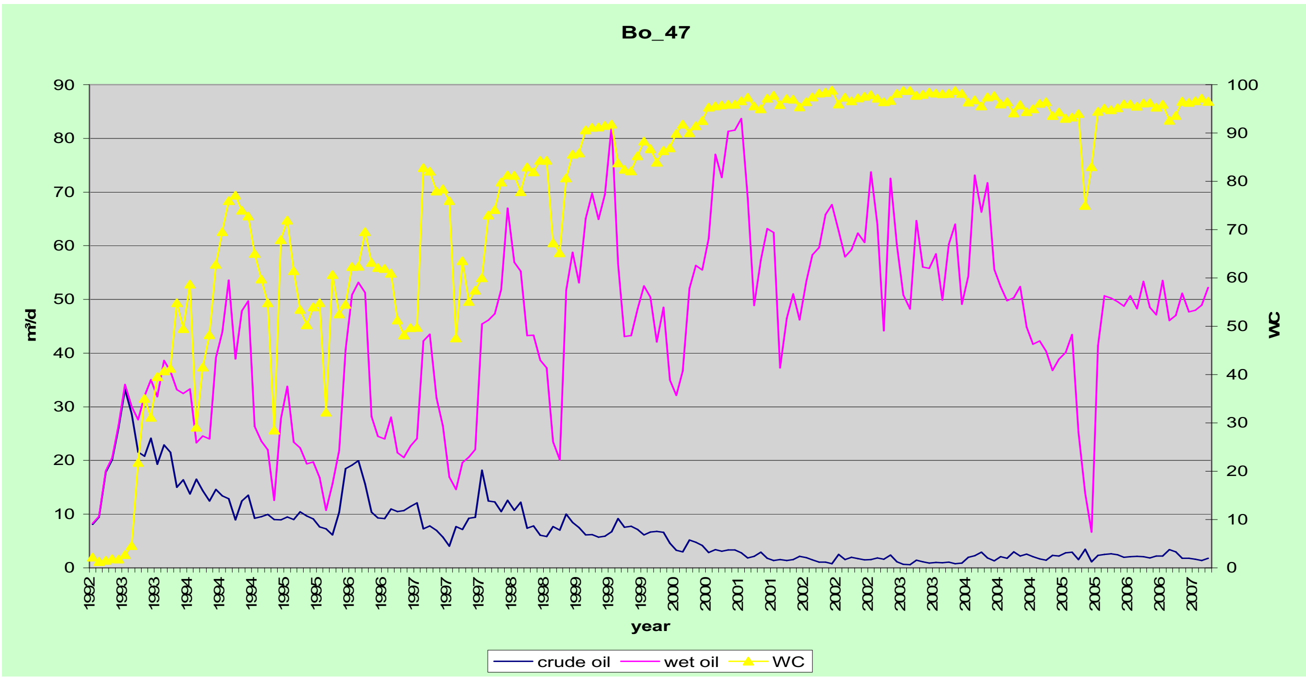

Fig.25 Diagnostic plot Bo_47

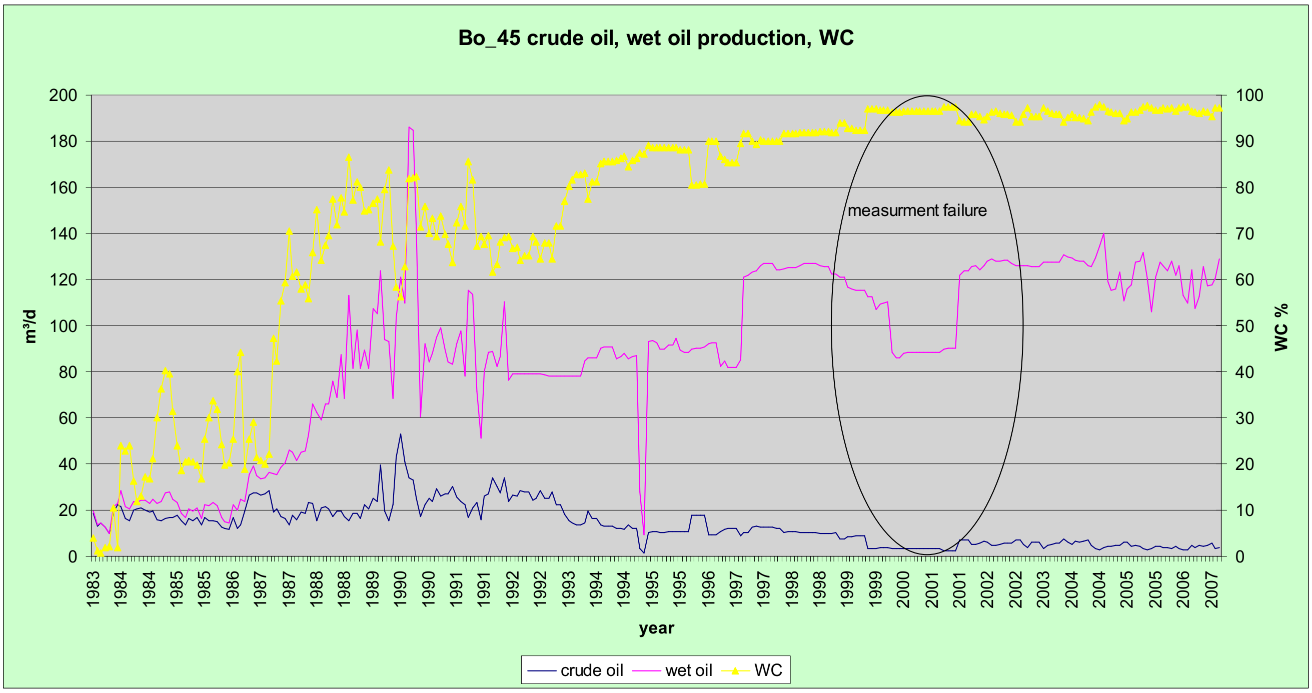

Fig.26 Diagnostic plot Bo_45

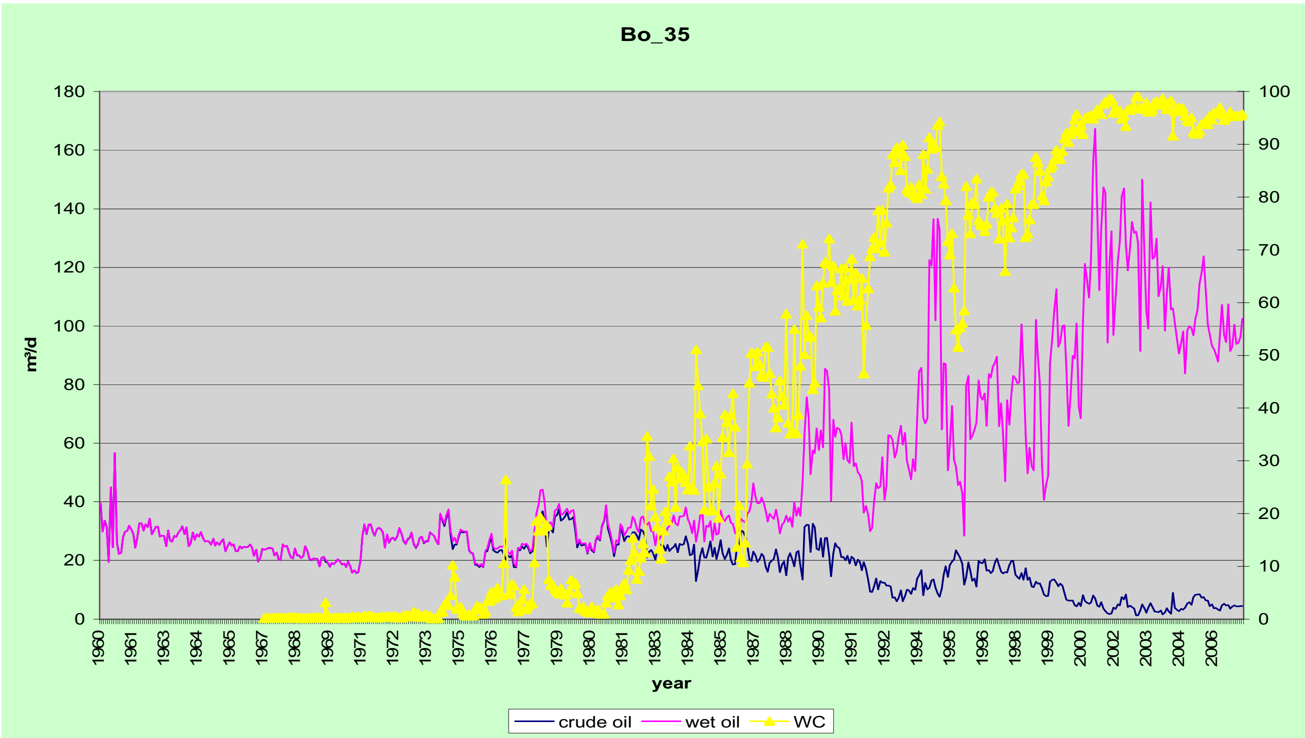

Fig.27 Diagnostic plot Bo_35

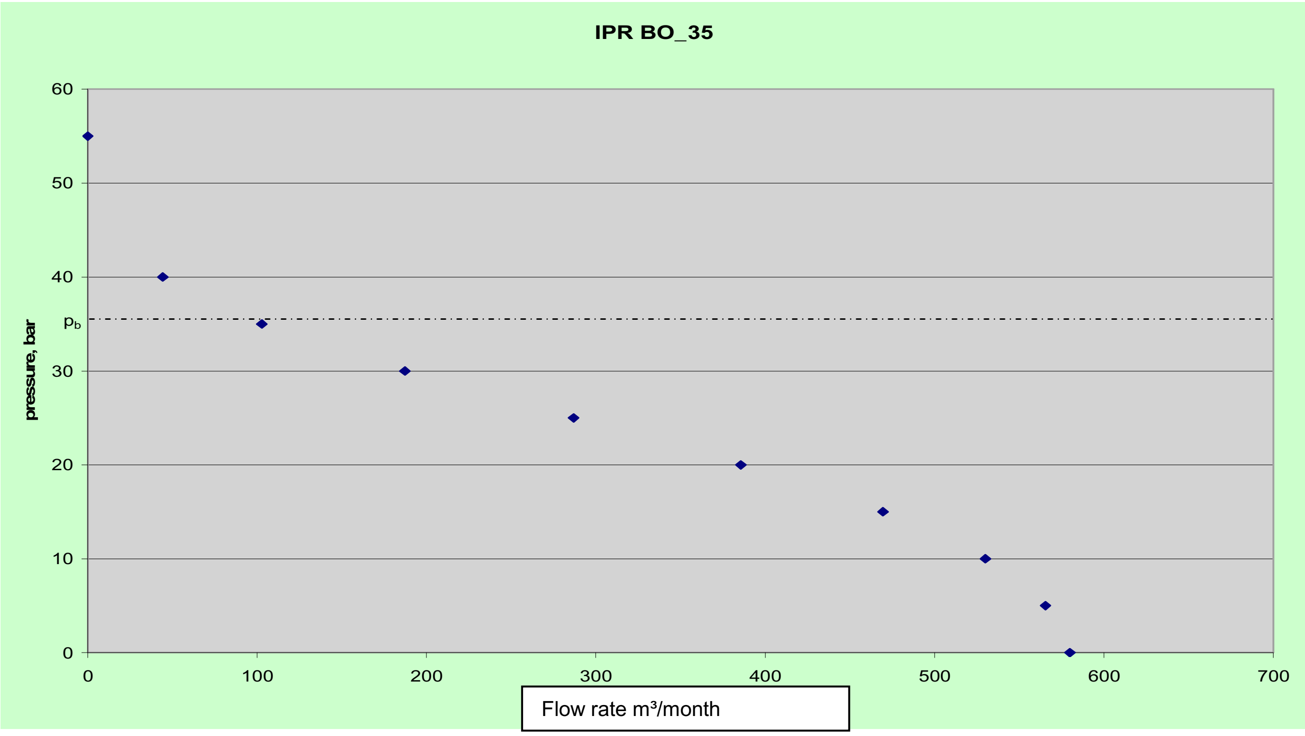

Fig.28 IPR Curve 35

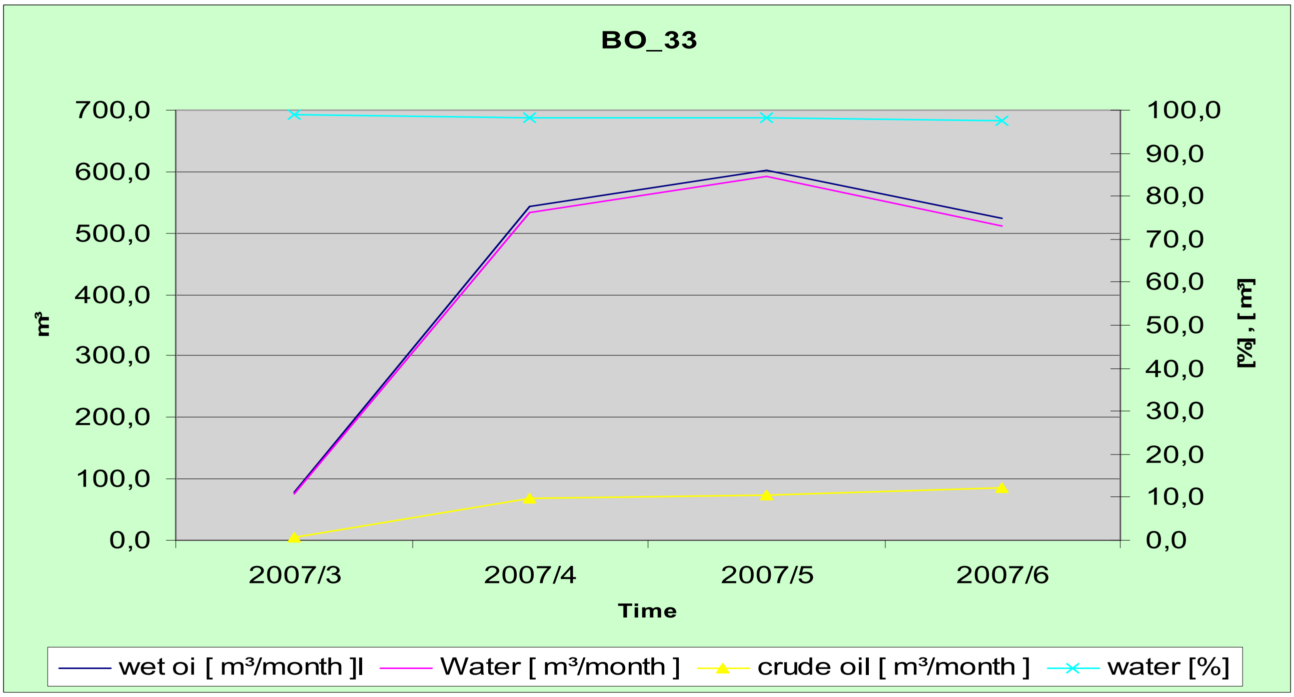

Fig.28 Bo_33 production development after WSO

6. Nomenclature

Permeability	k	[mD]
Density	ρ	[Kg/m³]
Viscosity (oil, water)	μ_o, μ_w	[Pas]
Initial Reservoir pressure	P_i	[bar]
Bubble point pressure	P_{bo}	[bar]
Capillary pressure	P_c	[bar]
Well flowing pressure	p_{wf}	[bar]
Bottom hole pressure -	BHP	[bar]
Time	t	[h], [min]
Length	L	[m]
Original Oil in Place	OOIP	[m³]
Production Rate (oil, water, gas)	q	[m³/d], [m³/month]
Water Cut	WC	
Porosity	ϕ	
Productivity Index	PI	
Mobility ratio	M	
Oil Formation Volume Factor	B_o	
Water Saturation	S_w	%
Oil Saturation	S_o	%
Oil relative permeability	k_{rw}	
Water relative permeability	k_{ro}	
Oil and Water Mobility	λ_w, λ_o	

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