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Water Pressure Measurement Inside a Hydrocarbon Column

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Abstract

This paper documents that it is possible to measure the pressure of water inside a hydrocarbon reservoir. The pressure difference between oil and water could provide valuable information about the hydrocarbon column height of a new discovery. Detecting changes in the hydrocarbon – water pressure difference could work as an early warning system for water approaching a field in production. Knowledge about the hydrocarbon column height could speed up the appraisal process, or guide infill drilling, saving time and money. The environmental impact will be reduced because fewer wells will have to be drilled.

In most hydrocarbon reservoirs the water phase is likely to be continuous even at a very low water saturation and at a significant hydrocarbon overpressure. This is because of the polar nature of the water molecule and the polarity in the surface of the minerals in the reservoir: Water sticks to the surface of the reservoir grains. Given enough time the pressure gradient through this thin film of water becomes the same as if the water was in bulk. By measuring both the water and the hydrocarbon pressure at a given depth inside a hydrocarbon reservoir it is possible to estimate the vertical distance down to the free-water level. The only additional information needed are the densities of the fluids.

The water has lower pressure and lower mobility than the hydrocarbon phase, therefore specialized equipment will be needed to capture the water pressure. The pressure measuring probe must have a hydrophilic filter to prevent invasion of the hydrocarbon phase.

The pressure measurement of the thin water film should be made in an undisturbed part of the reservoir, i.e. it normally cannot be made at the wall of a well. A hole through the wall of the well and a short distance into the reservoir should be made for the probe to secure a representative water pressure measurement.

Background

When a new hydrocarbon discovery is made it is difficult to know the size of the find. One of the most important parameters in the calculation of the reservoir volume is the oil/water contact. If the discovery well does not penetrate the oil/water contact directly it may be necessary to drill additional wells to appraise the discovery before a development decision can be made.

If the well is drilled through the oil/water contact it may be possible to detect it on the saturation log from the well, or from multiple pressure measurements at different depths in the discovery well. Figure 1 shows how the Free-Water Level (FWL) in an oil reservoir can be identified from a pressure versus depth plot. The FWL in a reservoir is the horizontal plane where water and hydrocarbon pressure are the same. The slope of the lines is defined by the density of the fluids.

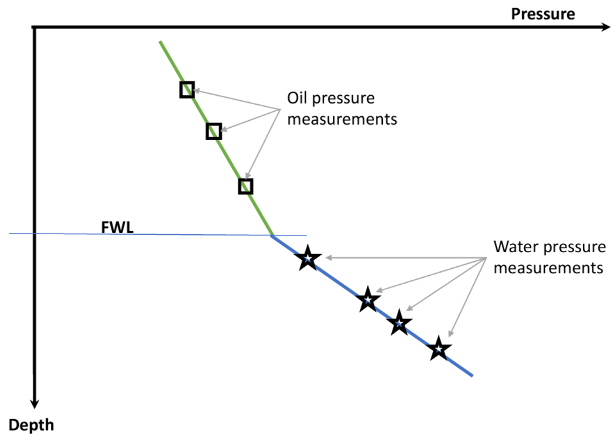

Figure 1—Current art: Pressure measurements at multiple depths defining the FWL

The oil/water contact (OWC) wil be immediately above the FWL only separated by the threshold pressure of the formation.

In some cases, the OWC cannot be estimated from either a saturation log or from a traditional pressure versus depth plot. Figure 2 illustrate one such situation.

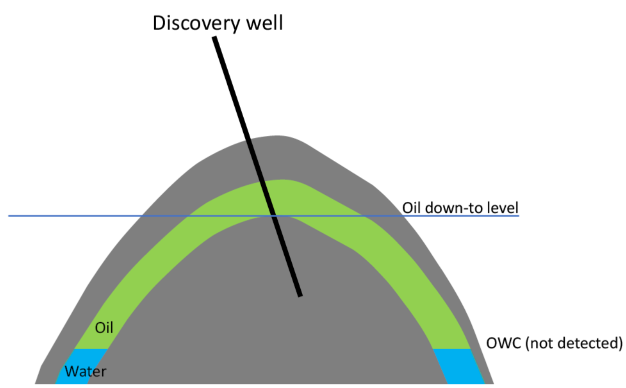

Figure 2—OWC not penetrated by the discovery well

However, by measuring the water pressure inside the oil reservoir the FWL – and the OWC - can be estimated. If we know the densities of water and oil, the pressure trends can be extrapolated downwards. The FWL is where the lines cross – see Figure 3.

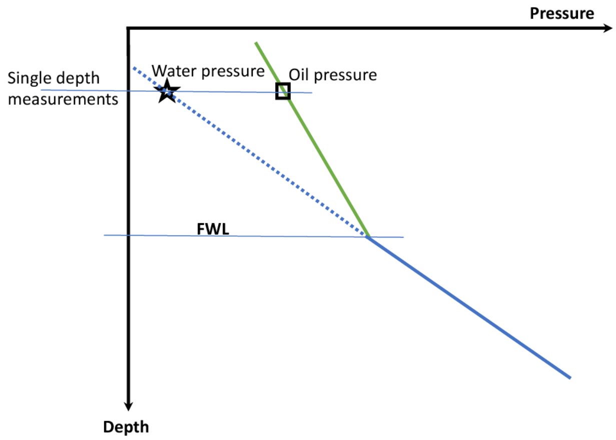

Figure 3—New art: Pressure measurements at a single depth. Density of the fluids are used to extrapolate the pressure trends down to the FWL.

If two measurements are made at different depths the densities – both hydrocarbon phase and water - can be estimated from the pressure changes.

For this to be possible a couple of criteria have to be fulfilled: the water film needs to be continuous all the way down to the aquifer, and the measurement must be made in a part of the reservoir that is not disturbed by water or surface-active chemicals.

Laboratory experiments

In order to demonstrate that the water pressure can be measured in a system with higher oil pressure a test rig was constructed (two actually) – see Figure 4 and Figure 5.

Figure 4—The test rig has a transparent acryllic core chamber and a probe feeder with ball valve. The probe and core can be moved relative to each other both radially and axially. Resitivity can be measured across the core. A porous plate at the outlet end allows water to be drained from the core. The core chamber is filled with oil. The oil pressure can be increased to 15 bar.

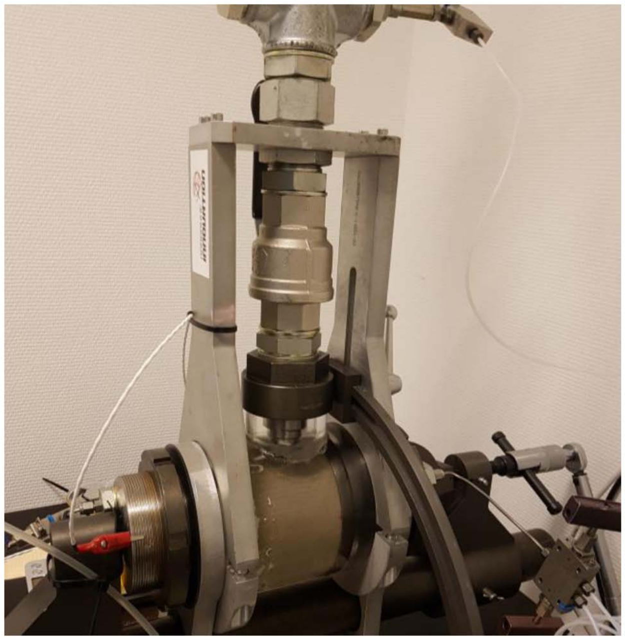

Figure 5—A picture of a 4″ Berea core during drainage with transparent Isopar H oil in the chamber. Probe coming in vertically from the top.

The probe shown in the picture has a hydrophilic microporous ceramic disc at the tip and the pressure transducer immediately behind the disc. Kaolin paste was used between the core and the ceramic filter to secure water continuity at the outlet, and to secure the connection between the ceramic disc at the tip of the probe and the surface of the core. Examples of how the water pressure development during drainage can be tracked is shown in Figure 6 and Figure 7.

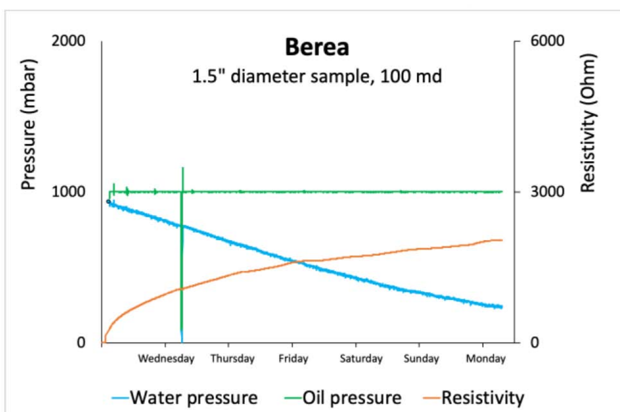

Figure 6—Water and oil pressure development during one-week drainage of a Berea core plug.

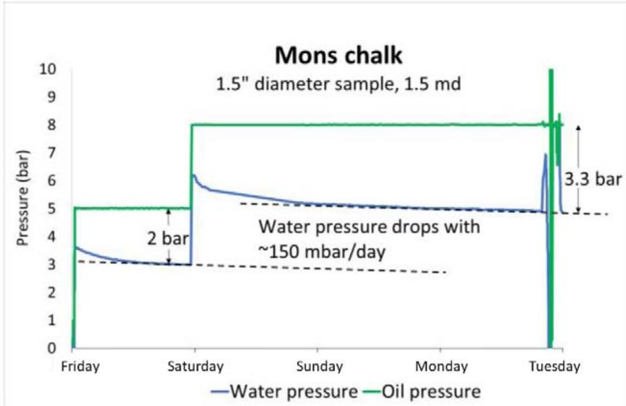

Figure 7—Water and oil pressure development during four days of drainage of a Mons chalk core plug. When the oil pressure is increased, water pressure increases simultaneously. After the sudden increase in oil pressure the decline in water pressure first gets steeper, but after about a day it settles back into a slower linear pressure drop. (The sharp pressure up/down spikes on Tuesday are due to handling of the probe – in/out of chamber etc.).

The mobility of water in a rock containing oil at higher pressure is low, but not zero (Ref. Teige). The mobility of water will – with time – bring the system to static equilibrium.

Response time

The time it takes to measure the pressure of the water with low mobility can be controlled by the volume exchange that takes place between the probe and the thin water film in the rock. The small volume of water which is pushed from the probe to the rock will cause a local increase of the water pressure. The water will then need some time to regain pressure equilibrium with the water inside the reservoir rock. The example shown in Figure 8 had response time of about one hour after a hard push of kaoline paste through the steel tube probe.

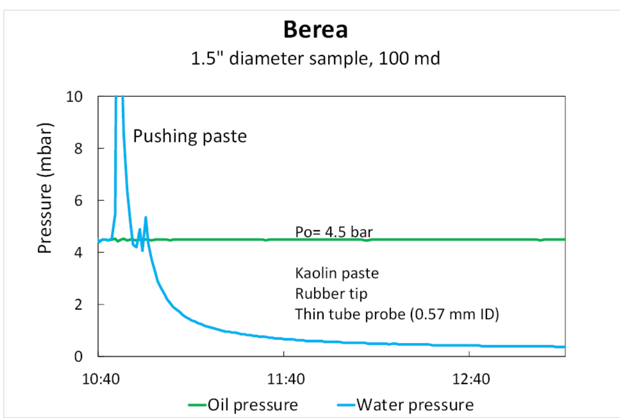

Figure 8—A thin tube filled with kaolinite paste was used to connect to the water in a Berea core plug pre-drained to 4.2 bar pressure difference with Isopar H. Response time of about one hour.

A response time of 25 minutes was seen when measuring on the same Mons chalk plug as in Figure 7. Figure 9 is a closer view at the last part of the pressure development shown in Figure 7.

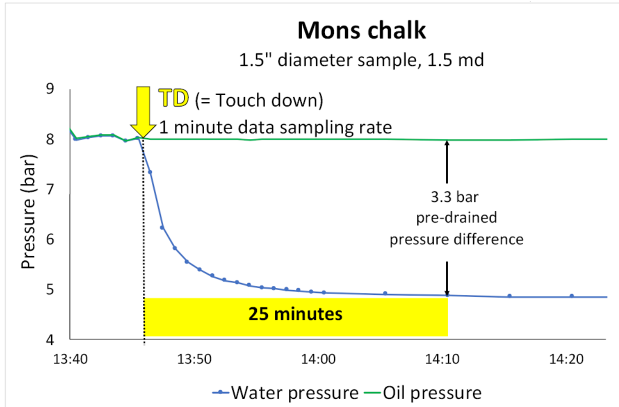

Figure 9—In this experiment a probe with a hydrophilic ceramic disc at the tip was used to measure the water pressure in a Mons chalk plug pre-drained to 3.3 bar pressure difference with Isopar H.

The response time in a realistic reservoir situation is likely to be faster than on a small cylindrical core plug because of the three-dimensional escape paths.

The volume exchange with the rock can be made smaller reducing the response time further.

Limitations

The water phase must be continuous all the way down to the aquifer for the technology to work. If water becomes discontinuous the pressure of the isolated water will be the same, or almost the same, as in the surrounding oil. If the reservoir rock has become less water wet the continuity of water could be lost.

This type of water pressure measurement will probably not provide any useful information if performed at the wall of the well.

For a well drilled with water-based mud there will be a small leak of mud filtrate that will inflate the water pressure immediately around the well. Simulations performed by NORCE with their simulator Maximize® (Ref. Lohne) estimate that the distance of inflated water pressure could be several meters out from a well when drilled in overbalance with water-based mud.

For a well drilled with an oil-based mud the surface-active components will turn the wall of the well and all surfaces a short distance into the reservoir oil-wet. In other words: The continuous film of water on the surface of the rock grains will be lost.

For a precise estimation of the free-water level (FWL) to be possible the reservoir pressure regime must have come to equilibrium. This can be a very slow process, but for a discovery well the equilibrium criteria are likely to be fulfilled.

So far, the thin water film pressure has been successfully measured while the pressure difference between oil and water have been > 6 bar and less than 10% water saturation. A pressure differential of 6 bar represent a 200-meter oil column when the oil density is 700 kg/m^3 at reservoir conditions. Higher differential pressure will be tested going forward to identify if there is a limit where the pressure measurement on the thin water film no longer can be performed.

Measurements on Mons chalk and Berea sandstone have been carried out. Both were easy to measure on. More tests will be carried out on a variety of rocks with a wide range in porosity/permeability.

How to measure?

A tool to perform thin water film measurements in a well have not been constructed yet, but a conceptual tool has been designed by Aarbakke Innovation (AAI). It is a wireline tool that will be lowered into the well, locked in place by two packers (Figure 10). There will be bypass lines to allow the fluids in the well to flow freely past the tool.

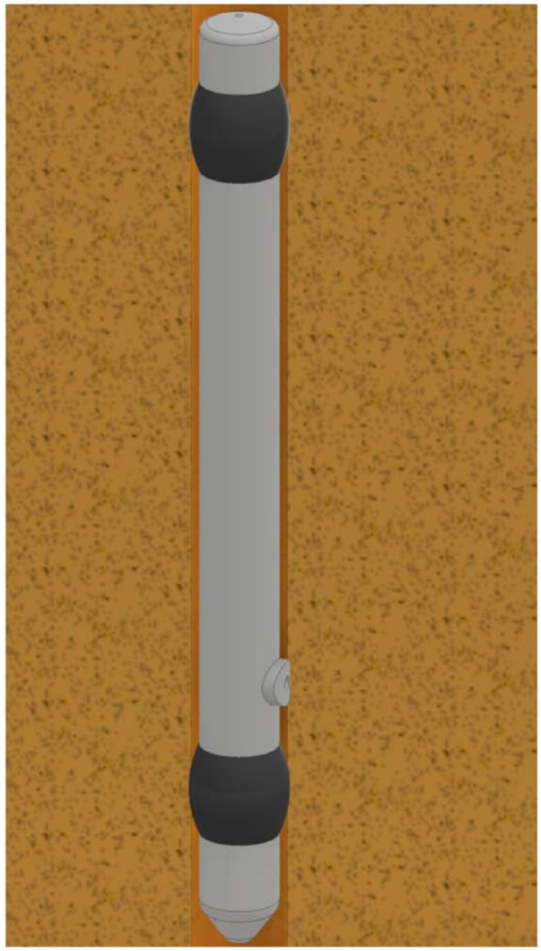

Figure 10—The tool has been lowered into the well, and the packers have locked it in position.

A clamp cylinder will be extended and seal against the formation (Figure 11).

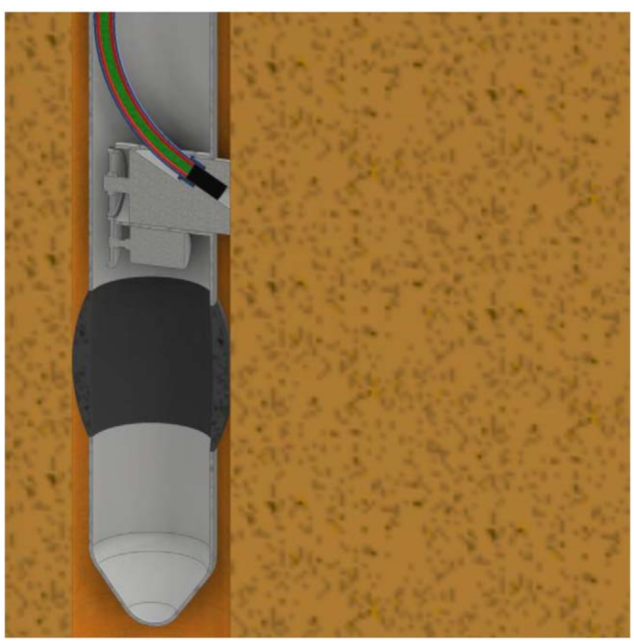

Figure 11—A cross-section of the tool with the clamp cylinder extended and forming a seal towards the wall of the well.

A small drill will penetrate the seal and create a hole into the formation (Figure 12). The drilling of the hole will be achieved using a specially designed drill bit (Figure 13 and Figure 14) and a clean oil carried inside the tool will be pumped through the micro casing, over the bit and circulated back through the annulus and into a waste container. The drilling will be performed in balance with the oil pressure of the reservoir. When the hole is deep enough the drive wire will be pulled back into the tool, and the probe will be inserted through the micro casing and the drill bit. It will then perform the water pressure measurement in virgin reservoir at the toe of the newly drilled hole. The oil pressure is also needed and can be measured anywhere in the tool since the oil inside the tool will be in pressure balance with the oil in the reservoir. The tool will benefit from a gamma ray log for position control, temperature measurement for pressure and fluid density corrections. Fluid sampling, density measurement and resistivity along the hole made for the probe would also provide useful supporting information.

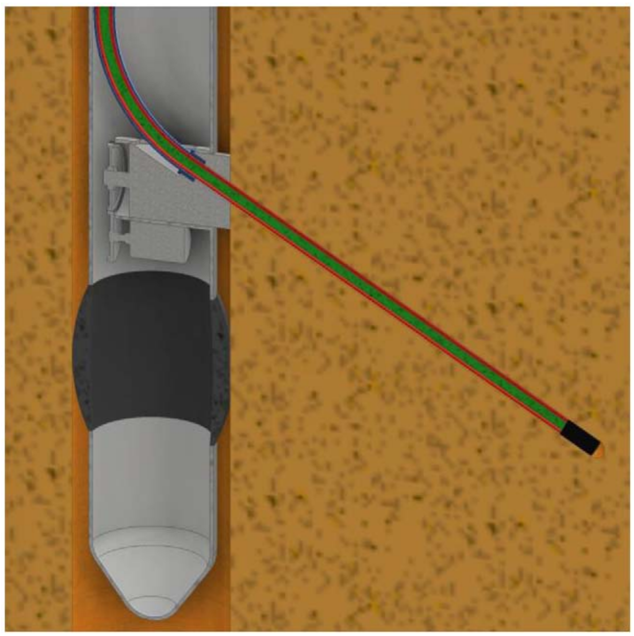

Figure 12—Drilling a hole into the formation

Figure 13—The drill bit with a needle bearing connection with the micro-casing

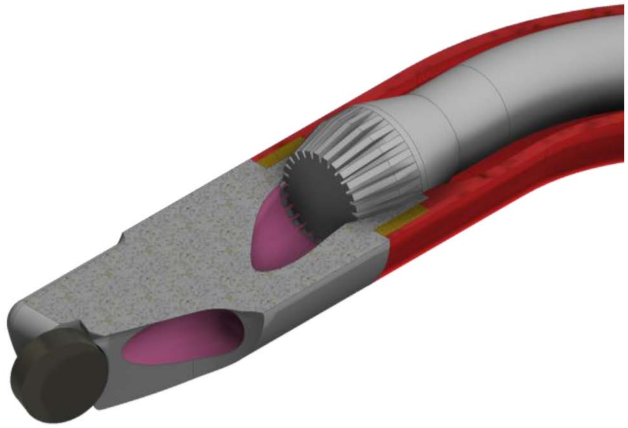

Figure 14—Cross section through the drill-bit and micro-casing with the drive wire connected

Reservoir monitoring

If a hydrophilic probe (Ref. Hydrophilic, patent pending) is permanently installed in a well in a producing field continuous information about the hydrocarbon overpressure in the reservoir would become available. Today such information is not available. Reduction in the hydrocarbon overpressure could become a way of monitoring if water is approaching the well. It could become an early warning system for water approaching the well, or an indicator of how much oil are accumulating around a well that are shut in. Measuring the pressure difference between hydrocarbon and water would be a more accurate way to predict the encroachment of water than a saturation log is today - see Figure 15.

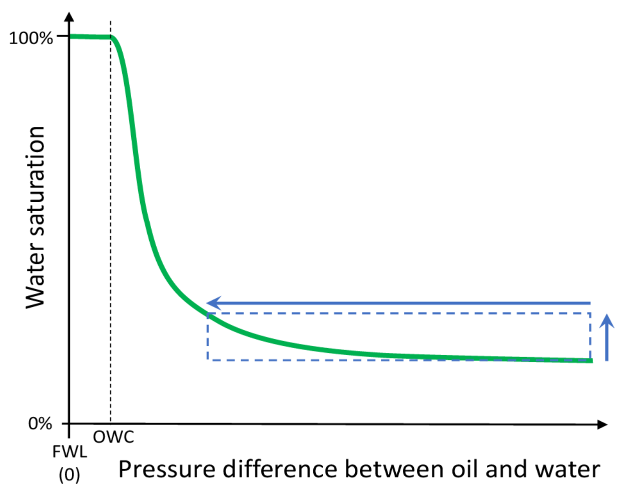

Figure 15—The water saturation in an oil reservoir is a function of the pressure difference between oil and water. When water starts to invade the reservoir the pressure difference between water and oil will drop significantly while the saturation change is still small.

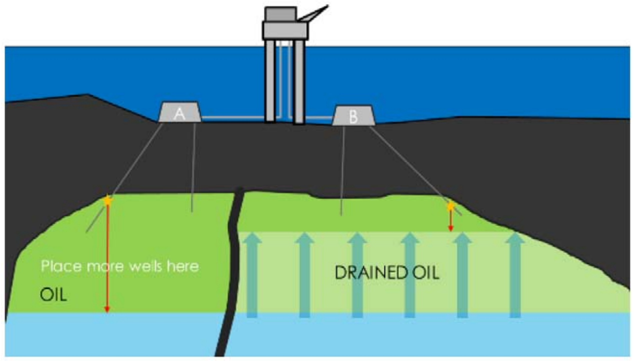

Figure 16—Permanently monitoring the pressure difference between oil and water could provide information about water encroachment before water is produced by the wells, and before it can be detected on saturation logs.

Conclusions

- It has been demonstrated that the pressure of water in the presence of over-pressured oil (> 6 bar), and at low water saturation (< 10%), can be measured.
- For a reservoir in pressure equilibrium, with a continuous water phase, the vertical distance down to the FWL can be estimated based on the pressure difference between the hydrocarbon phase and the water.
- Both the water and the hydrocarbon phase in the reservoir must be continuous for a pressure difference to occur.
- It is possible to build a tool that can perform the thin water film pressure measurement in a well.
- An accurate measurement of the thin water film pressure can be completed in minutes (less than an hour) after the hydrophilic probe touches the surface of the rock.

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The authors also want to thank VRI Rogaland for support to carry out a theoretical study at NORCE to validate the feasibility and potential of in-situ water pressure measurements.

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