Application of Acoustic Stimulation on RAG Production and Injection Wells

Master Thesis

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Affidavit

I declare in lieu of oath, that this master thesis is entirely of my own work. I have consulted only references cited at the end of this volume.

Philipp Herbert Winter

Leoben, November 2014

Abstract

Technology plays a very important role in our modern life, and this is also true for the petroleum industry. As more and more oil fields are entering brown field operation the need for new mechanisms to increase the recovery is very high. A technique that is not well established is the stimulation with seismic waves. The positive impact of acoustic waves on subsurface fluid flow was first observed in water wells following an earthquake, but also noise generated by humans such as the passing of a railroad was observed to cause fluctuations in the water level in the wells. Therefore it was tried to utilize this effect as a stimulation method.

A very important part of this thesis was to find out under which conditions the application of the aforementioned stimulation method showed positive results. This was achieved by looking into the past successful applications of such a technology and the extraction of the reservoir conditions under which it was performed. Furthermore, the possibility to use the acoustic wave stimulation as an alternative to conventional acid stimulation as a more environmentally friendly approach, or the probability to use both methods combined in order to increase the effectiveness, was discussed.

Based on that starting point oil fields currently under RAG operation that, are meeting the requirements were selected. The rendered results of this process are used as a base for further considerations concerning the application of the stimulation method.

Keywords: Hydropuls, Acoustic Stimulation, Seismic Waves, Stimulation, Recovery Increase

Zusammenfassung

Technologie nimmt einen sehr wichtigen Stellenwert in unserer Gesellschaft ein, dies gilt nicht weniger für die Erdölindustrie. Nachdem immer mehr Ölfelder im Bereich der „brown field operation“ betrieben werden, ist ein großer Bedarf nach neuen Mechanismen gegeben, die Helfen die Ausbeute der bestehenden Felder zu maximieren. Eine nicht weitverbreitete Technologie ist der Einsatz von seismischen Wellen als Stimulationsmittel. Der positive Einfluss von akustischen Wellen auf das untertage Fließverhalten in Wasserbrunnen wurde das erste Mal nach Erdbeben festgestellt, aber auch Wellen menschlichen Ursprungs, wie das passieren eines Zuges, erzeugte Fluktuationen im Wasserspiegel von Brunnen. Deshalb wurde versucht sich diesen positiven Effekt nutzbar zu machen.

Ein sehr wichtiger Teil dieser Arbeit war es, herauszufinden unter welchen Bedingungen, positive Erfolge mit dieser Art von Stimulation erzielt werden konnten. Dafür wurden vergangene erfolgreiche Einsätze von seismischen Wellen zur Stimulation genauer unter die Lupe genommen und die Lagerstättenparameter unter welchen sie stattgefunden haben extrahiert. Die Möglichkeit, dass akustische Wellenstimulation entweder gänzlich als Ersatz für herkömmliche Säuerung als eine umweltfreundlichere Alternative eingesetzt wird oder eine Kombination aus beiden Methoden, wurde diskutiert.

Basierend auf diesem Ausgangspunkt wurde eine Auswahl aus den RAG Ölfeldern, die zurzeit betrieben werden, durchgeführt. Die abgeleiteten Ergebnisse dieses Prozesses bilden die Basis für die weitere Anwendung dieser Stimulationsmethode.

Schlagwörter: Hydropuls, akustische Stimulation, seismische Wellen, Stimulation, Erhöhung der Ausbeute

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1 Introduction

Oil and gas are very important natural resources which are essential to meet the demand of the world's growing energy needs. The consumption of petroleum products is rising every year and it is necessary to support this growing demand. This can be achieved by exploration and development of new fields, which requires enormous investments and bears the risk of unsuccessful wells. Another solution in meeting the rising energy demand is to improve the recovery methods that are currently in use. This means utilizing new technology for hydrocarbon recovery.

The amount of oil that is recovered, compared to the total amount of oil that is estimated to be in the reservoir (original oil in place – OOIP) is given as a percentage called recovery factor. The average global recovery factor for oil fields is approximately 35% (1). This factor is governed by reservoir specific parameters, economic parameters and by the technology that is used to recover the oil. The technical limit for oil recovery is approximately 60-70% (1). Therefore it is a very important objective in the petroleum industry to maximize the economic use of the utilized technology to increase the recovery factor.

Figure 1 gives an overview of the different approaches that are being used to recover hydrocarbon resources from the reservoir. It divides the recovery of oil into three categories which are primary, secondary and tertiary recovery. Primary recovery utilizes the natural energy of the reservoir. However it is possible to use the support of artificial lift systems, if the driving mechanism is not strong enough, to produce the liquids freely, either due to the fact that there is not enough energy from the beginning or due to depletion,

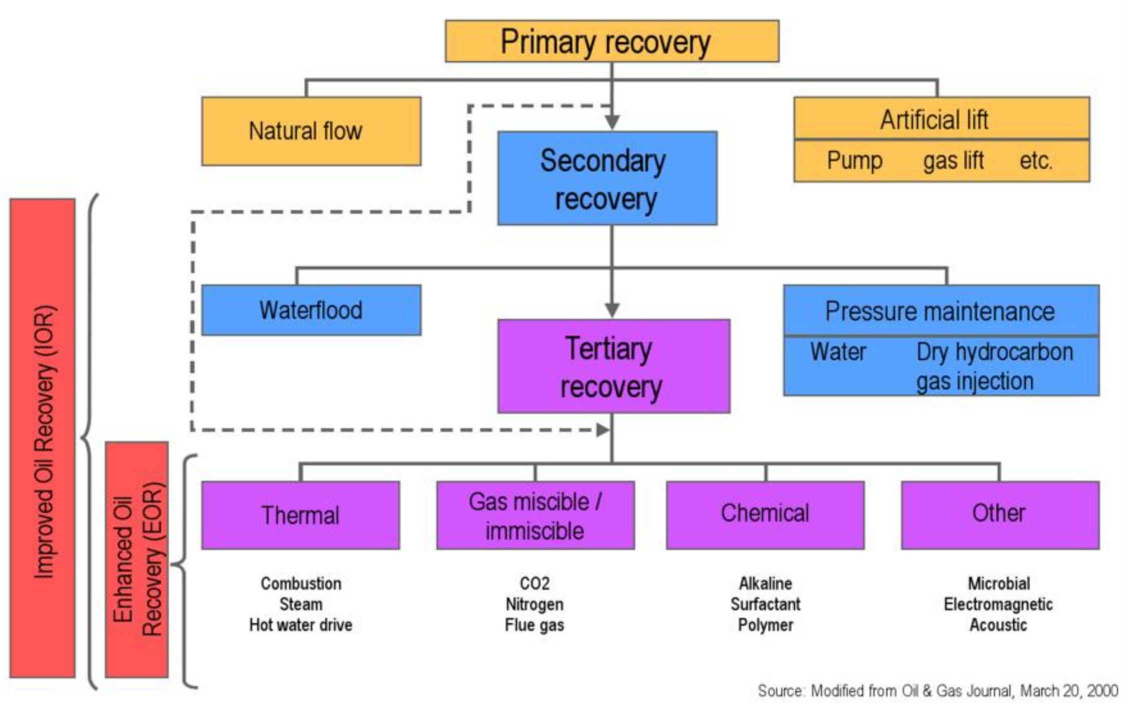

Figure 1: Overview of recovery mechanisms in use in the petroleum industry (Diagram modified after Oil and Gas Journal)

During the course of production pressure is decreasing since fluids are removed and consequently secondary recovery mechanisms are required to add energy to the reservoir in order to keep the operation within an economic region. The applied method is depending on physical displacement of produced reservoir fluids.

As the production of a hydrocarbon field is continuing, secondary recovery may become uneconomic. At this point tertiary recovery may be an option to prolong the life of an oil field, it deals with the fluid flow conditions and properties to improve the movement of oil through the reservoir. Methods used include the injection of steam, water and gas, but also more sophisticated substances like surfactants, polymers or acids are introduced to the reservoir to improve the recovery (2).

1.1 Primary Drive Mechanisms

Primary recovery begins with the first initial production of a field and lasts until the drive mechanism is no longer sufficient enough to ensure an economic production. Throughout the production the pressure in the reservoir is lowered, primary recovery can therefore also be referred to as pressure depletion. Several different mechanisms are characterized as primary drive mechanisms.

1.1.1 Rock and Fluid Expansion Drive Mechanism

When production is starting the pressure in the reservoir is declining which allows fluids and the rock to expand, due to their compressibility. As the pressure is decreasing in the reservoir, the fluid pressure also is declining allowing the grains to expand and the formation to compact which forces the fluids out of the pores and into the wellbore. As the production continues, the porosity is decreasing, due to the fact that the reservoir is compacting. There is also the possibility of surface subsidence in shallow and unconsolidated reservoirs. The basic characteristics of this type of depletion is a rapid decline in reservoir pressure, the gas oil ratio (GOR) remains low, the water production is nearly none existing and the ultimate recovery is around 1% to 10% (3) of the stock tank oil initially in place (STOIIP). This driving mechanism is considered to be the least effective primary mechanism.

1.1.2 Depletion Drive Mechanism

If the initial reservoir pressure is above bubble point pressure (p_b), the reservoir is then called undersaturated. The gas in the reservoir is in solution in the oil. As the production commences the pressure is declining until it falls below the bubble point pressure, at which point the gas is liberated from the oil. The forming gas bubbles are expanding and driving the oil out of the pore space. The gas is produced alongside with the other fluids. If the reservoir pressure is above bubble point there is no free gas and the only driving force is the expansion of the reservoir rock and the fluids. The following points are indicative for a depletion drive reservoir. The reservoir pressure declines rapidly in the initial phase until the bubble point is reached, where the pressure decline curve gets less steep and flattens out. At the beginning the gas oil ratio is constant, later when the pressure is reaching the bubble point pressure, gas starts to get out of solution, but it cannot flow until it reaches critical gas saturation. This can be seen by a decline in the GOR to a certain level where it starts to rise until it reaches a maximum and drops off afterwards. The oil rate rises in the beginning and reaches a high point after reaching the bubble point. After a maximum the rate declines rapidly. If properly produced, there should be very little water production. The ultimate recovery of a solution gas drive reservoir ranges from 5% to 30% (3) of STOIIP.

1.1.3 Gas Cap Drive

On top of the oil sits a gas cap that is expanding as the oil is produced and this is, together with the expansion of the liberated solution gas, the driving force of this reservoir type. During the production of a gas cap drive the reservoir pressure is falling in a slow continuous way and usually stays at a higher level than in the case of a depletion drive reservoir. The rate of pressure decline depends on size or volume of the gas in the cap in relation to the oil volume. Water production is normally not existing or in a negligible amount. The gas oil ratio is continuously increasing. As the gas oil contact is moving downwards the expanding gas cap reaches the production interval of the well, at which point the gas oil ratio will increase significantly. Oil recovery by this driving mechanism is a lot more effective than for the aforementioned mechanisms, because the expanding gas cap can be seen as a displacing type drive. The ultimate recovery is usually expected in the range of 20% to 40% (3).

1.1.4 Water Drive Mechanism

Hydrocarbon reservoirs may be connected to water bearing formations which are called aquifers. On the one hand those aquifers can be so large that when compared to the size of the oil reservoir they can be considered infinite for practical production estimation purposes, on the other hand they can be so small that they can be neglected, when considering the effects on the reservoir performance. The aquifer and the oil bearing formation can be entirely surrounded by sealing boundaries, in which case they would form a closed structural unit. It is also possible that the formation that is containing water is outcropping and may therefore be refilled with water coming from the surface. As the oil is produced from the reservoir, water is moving upwards, replacing the removed oil and displacing it towards the production wells. The typical decline in reservoir pressure is very slow and linear. The reason for the small decline rate is that the voided volume will be replaced by encroaching water while gas and oil are being removed. For wells with structurally low production intervals there will be an early occurrence of water production. The overall water production for all wells will increase over the lifespan of the reservoir to significant amounts. Since the reservoir pressure is declining so slowly, there is very little change in the producing gas oil ratio, since not much gas will be liberated from the oil. The ultimate recovery of water drive reservoirs is usually the highest among the different mechanisms. The efficiency of the recovery is greatly depending on the reservoir heterogeneity, the higher it is the less efficient the production will be, because the encroaching water will not enter the reservoir uniformly. This means in some areas the water oil ratio will reach such high values, that economic production cannot be maintained anymore. The ultimate recovery usually ranges from 35% to 75% (3).

1.1.5 Gravity Drainage Drive

The driving force of the drainage drive mechanism is the density difference of the reservoir fluids. The heavier fluids are encountered on the bottom of the reservoir, whereas the lighter fluids (usually oil) will be above and if there is free gas, it will be on top. The separation of the liquids occurs due to gravitational forces that are acting. In some reservoirs this gravity segregation will contribute to a big extend to the overall production of the oil. Normally there is no reservoir that is only driven by gravity drainage, but rather by a combination with another mechanism. So it is difficult to make a pressure prediction for this type of reservoir, but if the assumption was made that the only drive mechanism present is gravity drainage, the reservoir pressure would show a rapid decline. If the pressure sinks below the bubble point pressure it is possible that a secondary gas cap is formed. The ultimate recovery range from gravity drainage is widely spread. But it is possible that values as high as 80% (3) may be reached.

1.1.6 Combination Drive Mechanism

In reality most of the time there is a combination of different mechanisms encountered, where water from an aquifer as well as free gas are available to displace the oil towards a well. Most commonly there are two different combinations present in a combination drive reservoir:

1. Depletion drive with a weak water drive
2. Depletion with a small gas cap and a weak water drive

The reservoir pressure typically shows a rapid decline, because the advancing water or the expanding gas cap is not efficient enough to maintain the reservoir pressure. The gas oil ratio will show a steady increase for wells with a structurally high production interval, if the gas cap is expanding.

1.1.7 Artificial Lift

If the reservoir pressure is not high enough, that the well can lift liquids on its own, it is necessary to utilize artificial lift technology. Also if the well is not delivering a production rate that is high enough to operate in an economic way, artificial lift may be a possible solution to keep it profitable.

The most important artificial lift methods are:

- Sucker rod pump
- Progressive cavity pump (PCP)
- Electrical submersible pump (ESP)
- Gas lift
- Plunger lift
- Reciprocating and jet hydraulic pumps

Depending on different well conditions the above mentioned artificial lift methods are applied. The selection of the most economical artificial lift method is a very important part during the course of production of an oil field. The best fitting method is chosen based on different parameters, including:

- Desired rate and setting depth of the pump
- Borehole trajectory
- Possibility of sand production
- Gas liquid ratio (GLR)
- Experience based on other successful operation at similar conditions

Furthermore it is important to evaluate the costs, that in contrast to the increase in production of oil.

1.2 Secondary Recovery

When primary recovery mechanisms are not efficient and economic anymore it is necessary to go one step further, as can be seen in Figure 1. The idea behind is to add energy to the reservoir, to enable additional recovery of oil, in order to keep up the pressure and to displace the hydrocarbons towards the wellbore. The added driving force is normally in the form of reinjected water or gas. This process can be seen as a support for the natural mechanisms, when they are not strong enough anymore. There is a positive side effect to water injection, usually during production the water cut which is the percentage of water production to the whole liquid production is rising and reaching very high levels. It is then necessary to dispose this formation water in the most environmentally friendly way possible. This can be either done in a treatment plant or by reinjecting the water into the formation where it originated from.

1.3 Tertiary Recovery

Tertiary Recovery goes one step further, where primary and secondary recovery is not able to ensure profitable operation. Energy of a different kind is added to allow the additional extraction of oil. The main idea behind tertiary recovery is to alter the properties of the fluids to increase the movement through the reservoir. The diagram in Figure 1 divides this type of recovery into four different parts, which are *thermal*, *gas miscible/immiscible*, *chemical* and *other*.

The main idea behind thermal recovery is to introduce heat to the reservoir, to achieve more favorable oil conditions. This means that viscosity, density and interfacial tension are altered. The methods that are used to bring additional energy into formation include:

- Combustion
- Steam
- Hot water

The gases that are used for injection in the next recovery method are not naturally occurring in the reservoir. The used types can be divided into two categories: miscible and immiscible. When miscible gas (like carbon dioxide,

CO_2) is injected it will mix with the oil and reduce the viscosity to increase the ability to flow. Immiscible gas (like Nitrogen, N) is used to increase the pressure and drive the oil out of the reservoir.

The third category described in Figure 1 deals with chemical injection to alter the properties of the liquids present in the reservoir, remove formation damage caused by drilling or perforation operations, and also inhibits corrosion in the production facilities.

The last part is generally termed *other* and includes methods that are either new or not well established and widespread in the petroleum industry. Methods that can be put into this category include microbial, electromagnetic and acoustic, which will be the concern of this work.

1.4 Reservoir Specific Parameters

To ensure an economic production of an oil field, there are important reservoir specific parameters that play a key role in achieving that goal. These parameters govern the deliverability of a reservoir or well respectively and also give an indication about the hydrocarbons that are estimated to be in place in the reservoir.

1.4.1 Porosity

The porosity is defined as the ratio of the void or pore space and the bulk volume of the reservoir.

$$\phi = \frac{V_{pore}}{V_{bulk}}$$

The parameter can be further specified into total and effective porosity. Whereas total porosity gives, as the name suggests, the total void space that is existing in a reservoir, the effective porosity only accounts for pores that are connected and communicating with each other. So the total porosity quantifies the volume that can be filled at the most with liquids, whether they are water, oil or gas. The effective porosity on the other hand gives the volume that is connected and can therefore be moved through the reservoir.

A further classification divides porosity into primary and secondary. Primary porosity is formed during the deposition of sediments. Secondary porosity can be formed during diagenesis, by dissolution of grains.

1.4.2 Permeability

The second important reservoir parameter is permeability. It measures the ability of a porous rock to transmit fluids. So the higher the permeability, the higher the amount liquids can be delivered from the reservoir to the wellbore. That means that permeability is a critical factor that governs how economically a well can be operated. It was first defined by Hendry Darcy in 1856 in the following equation called Darcy's Law:

$$q = -\frac{kA}{\mu}\frac{dp}{dL}$$

Where	q	Flow rate [cm³/s]
	A	Cross-sectional area [cm²]
	k	Proportionality constant (permeability) [Darcy]
	μ	Fluid viscosity [cP]
	dp/dL	Pressure gradient [atm/cm]

It is valid for a single phase and incompressible fluid. If the flow rate is 1 cm^3/s, the area 1 cm^2, the fluid viscosity 1 cP and the pressure gradient 1 atm/cm the permeability is 1 Darcy. It is also called absolute permeability in that case. Since 1 D is a very high value for the typical reservoir, the unit millidarcy (mD) is used in practice to quantify the permeability. Since Darcy's Law is only valid for single phase fluids and in a typical reservoir more than one liquid is present the concept of relative permeability is used to account for that. The measured permeability for a specific phase is called the effective permeability. It is a measure of the conductance of a porous medium for a particular phase, when there is more than one fluid present. The effective permeability is a function of fluid saturation and the wetting characteristics of the reservoir. It is measured for each phase present and noted as such:

k_o Effective permeability of oil
k_g Effective permeability of gas
k_w Effective permeability of water

This effective permeability is used in Darcy's Law to calculate the flow rate of one particular phase.

$$q_w = -\frac{k_w A}{\mu_w}\frac{dp}{dL}$$

Where q_w Flow rate of water [cm^3/s]
k_w Effective permeability of water [Darcy]
μ_w Viscosity of water [cP]

The effective permeability is usually measured in the laboratory for different saturations and is then usually summed up as relative permeability, which is defined as the ratio of effective, at a specific fluid saturation, to absolute permeability and its value lies between 0 and 1. It is displayed visually in a relative permeability curve. There are two endpoint saturations in the diagram, they are called the connate or irreducible water saturation (S_{wc}) and the residual oil saturation (S_{or}). If such an endpoint is reached, the corresponding phase becomes immobile and can no longer be moved through the reservoir.

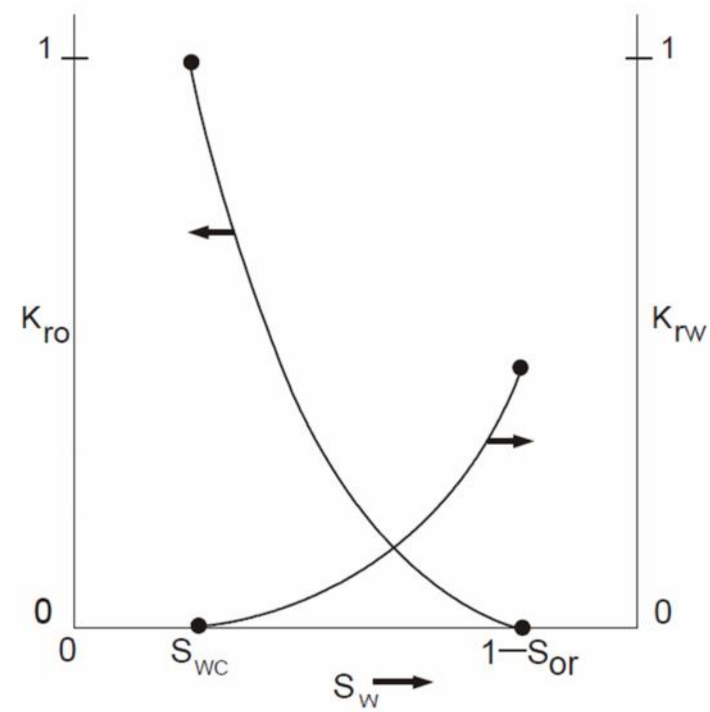

Figure 2: Relative permeability curve for water and oil, with the two endpoint saturation S_{wc} and S_{or} (4)

Another important reservoir parameter is the wettability. It gives the ability of a specific fluid to coat the surface of the rock. The wetting phase occupies smaller pore openings at smaller saturations. Since those small openings do not contribute as much to the flow as the bigger ones, a small wetting phase saturation will not significantly influence the relative permeability of the non-wetting phase. On the other hand, the non-wetting phase occupies the larger pore openings, that are significantly contributing to the flow, so a small non-wetting phase saturation will have a big impact on the wetting phase permeability and will strongly reduce it.

1.4.3 Capillary Pressure

When two immiscible fluids are in contact, there is a difference in pressure between them; this is called the capillary pressure. It is resulting from different parameters in a porous medium. It is depending on the interfacial tension between the rock and the fluids, wettability of the reservoir and the size of the pore. To displace the fluid through a pore throat it is necessary to overcome the capillary pressure, the pressure gets higher the smaller the pore diameter is.

1.5 Wave Propagation through Porous Media

When a wave is travelling through a medium its intensity is diminishing, therefore, the wave becomes weaker the further it travels. The wave is subject to absorption and scattering, which means that it is reflected in a different direction that is not the original one. Both effects together cause the wave to get attenuated. As the wave is going through a medium, it may encounter changes in density of the medium, as it is the case of a typical reservoir, which shows some sort of heterogeneity. If the variations in density are rather high, that means for the wave that it gets reflected more often and hence, the attenuation effect is stronger. For a porous rock formation with a high degree of heterogeneity this means that a wave travelling through it will not penetrate as far as it would in a homogeneous medium.

Seismic waves are elastic waves that propagate through the earth. As they travel through a rock formation they cause elastic deformation (elastic means that the deformation vanishes as soon as the stress is gone). This has also an influence on the pores and their fluid content to some extent

2 Acoustic Stimulation

Acoustic wave stimulation is a technology that has been in use extensively in Canada and Russia. Numerous laboratory and field studies have been conducted on this topic and there are a lot of different results existing. They are ranging from a moderate increase of 20-40% (5) in oil production on average up to very high values which cannot be expected to happen on a regular basis. But there are also reports about experiments that resulted in a negative outcome, where the oil rate did not change and the relative water production (water cut) was increasing.

So it is very important to find out which parameters are mentioned in the literature, that are critical for a successful application of acoustic stimulation.

2.1 History of Acoustic Wave Stimulation

Observations of the positive effect of elastic waves on the delivery of water wells were first made in the 1950s (6). Most of the existing historical information on the impact of waves, either caused by humans or naturally occurring, is concerned with water wells. But there are also numerous records about similar effects caused in oil wells. Beresnev and Johnson (1994) (6) are providing a very profound overview of the observations of the effects of acoustic waves on fluid bearing formations.

2.1.1 Water Wells

The inspection of water wells showed, that there is a direct connection between the fluid levels and seismic excitation that is originating from cultural noise and earthquakes. Figure 3 below shows a distinctive change in water level in a water well with a depth of 52 m, when trains were passing by. The variations caused by trains were given with approximately 1-2 cm (7).

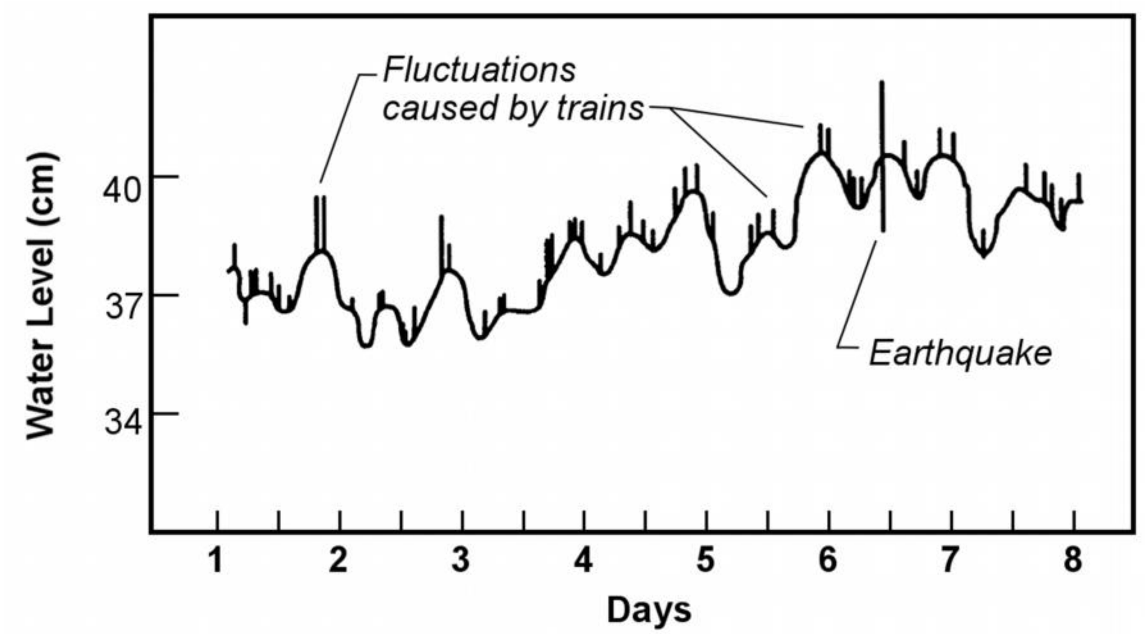

Figure 3: Fluctuations of the water level in a water level with a depth of 52 m induced by passing trains and an earthquake (7)

The fluctuation caused by an earthquake is also seen in Figure 3, but unfortunately, nothing is mentioned about the distance to the epicenter of the earthquake. The same publication is mentioning a fluctuation of 1.4 m of liquid level in a water well in Florida caused by an earthquake with an epicenter distance of over 1200 km.

Studies about the influence of waves on water levels in wells using artificial sources were also conducted. Barabanov et al. (1987) conducted a field trial, where different water wells with depths ranging between 100 and 300 m where stimulated using an artificial power source to generate seismic waves between 18 and 35 Hz. They monitored the changes in liquid level for each well which was between 1 and 20 cm. Besides the changes happening immediately during the stimulation with seismic waves, they also recorded a deviation from the average levels from before the excitation. This period lasted up to 5 days (7). When the reservoir was stimulated at resonance frequency, it was reported, that it showed the strongest effect. Resonance of a system is shown, when it is oscillating with higher amplitudes at some frequencies than at others. When a system is excited at resonant frequency small periodic oscillations can cause large amplitudes.

After a Californian earthquake in 1993 a rise in fluid pressure in an aquifer was observed which increased by 4.3 (8) times and the decay period, lasted for several days to weeks until it reached normal levels again. The rate of normalization was consistent with previous observations for seismic stimulation.

An earthquake in Alaska in 1964 caused changes in fluid levels in water wells all around the world (9). For each well an impact was observed immediately after the wave passed.

2.1.2 Oil Wells

Similar to water wells there are also numerous records about the behavior of oil wells during an earthquake and the period afterwards. Table 1 shows a summary of the results of case studies that are dealing with this topic. The results are shown in a chronological order.

Steinbrugge and Moran (1954) (10) reported variations in oil production caused by an earthquake in Kern county, which happened on July 21, 1952. On the one hand some wells showed an increase in casing pressure many times higher than the average before the earthquake. But on the other hand several wells in the same field did not show any changes at all. This differential behavior of the individual wells is an indication for the complexity of the underlying mechanism.

Table 1: Summary of publications about the influence of earthquakes on oil production (6)

Reference	**Field location**	**Earthquake magnitude**	**Epicentral distance (km)**	**Observed effect**	**Duration of effect**
Steinbrugge and Moran (1954)	Kern County, California	7.6	80	Increased and decreased production, increased casing pressure	
Smirnova (1968)	Cudermes field, Northeastern Caucasus	3.5-4.5	10-15	Increased oil production, largest effect near faults	Less than a month
Voytov et al (1972)	Different fields in Daghestan and Northern Caucasus	6.5	50-300	Large changes in oil production, renewed production for abandoned wells	Several months to three years
Osika (1981)	Anapa, Northern Caucasus	5.5	100	Increased oil production for some wells, pronounced near anticlines	

One specific example of two neighboring wells is clearly showing diversity in results. The first well had an increase in production from 20 bbl/day to 34 bbl/day (10) (1 bbl equals 159 l) and the second well showed a decrease from 54 bbl/day to 6 bbl/day (10). Smirnova (1968) observed the behavior of wells in the Gudermes Field in the Northeastern Caucasus. One particular well showed an increase of 30% (11) in production after two earthquakes on March 23, 1950. The distance was 10-15 km with a magnitude of 3.5 for the first and 4.5 for the second earthquake. During two other earthquakes in August 1955 (magnitude 3.5 and 4.5 respectively) all the wells in the oil field showed either an immediate or a delayed change in production. The effect of modified rate lasted for more than a month and it was most distinct near anticlinal inactive faults.

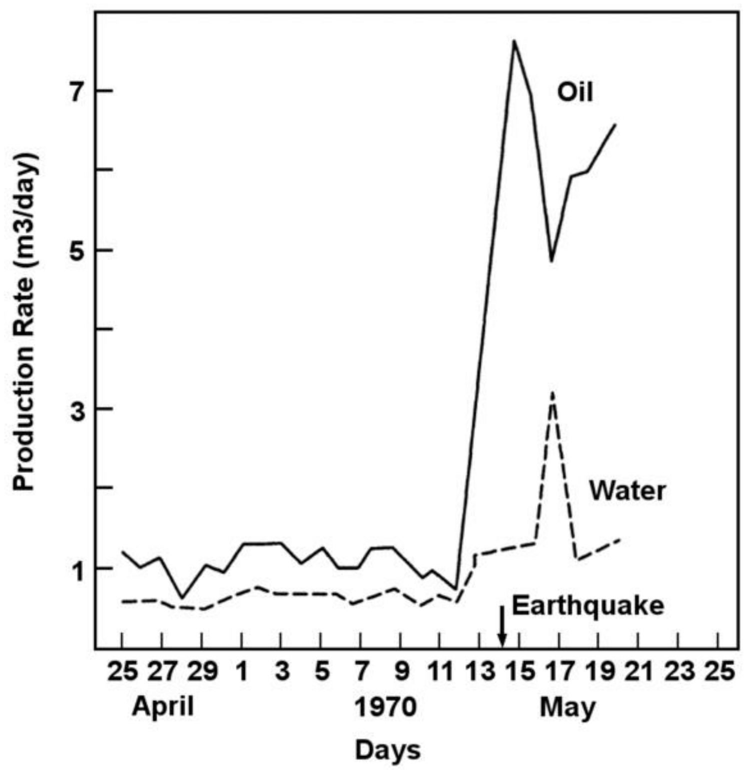

Figure 4: Response of daily oil and water production of a well in an oil field in Daghestan to an earthquake on May 14, 1970 (12)

Figure 4 is from the work of Voytov et al. (1972) (12). It shows the change in production for a well in an oil field in Daghestan. The earthquake happened on May 14, 1970 at a distance of 50 km with a magnitude of 8 at the epicenter and 6.5 where the well was located. The graph shows a sharp increase in both oil and water production. The effect seems to take place before the event of an earthquake. This is due to the fact, that sample values are taken once a day and the data points are connected by straight lines. The largest changes in oil production were encountered near inactive faults. Abandoned wells in the oil field showed oil and water outflow where the earthquake showed highest seismic intensity. Those wells did not show any outflow in the past several years and it continued through 1974.

Osika (1980) (13) did also research the Daghestan earthquake (also mentioned by Voytov et al. (1972)). In particular he gives observations he has made in the Kolodeznoye oil field, located 300 km away from the epicenter of the earthquake. Where oil production from well number 5 increased immediately after the shock from 51.8 m^3/day to 73.6 m^3/d. Well number 162 showed a reservoir pressure increase of around 10%-15% and a third well (no. 130) showed an increase in fluid level by 9 m. As already mentioned in other publications, he also observed that the effect was more noticeable near anticline domes.

Osika (1981) (14) examined data from several earthquakes in the Caucasus region. He mentions an earthquake in 1966 in the Black Sea with the epicenter 100 km away from the oil field Abino-Ukrainskaya where some wells showed increased production following the earthquake.

Comparing the results and observations of different publications and reports shows the erratic behavior of the stimulating effect of acoustic waves. Therefore, there is little chance for predictions of a single well.

2.1.3 Laboratory Studies

Various laboratory tests were carried out on core samples, to further study the effect of vibration on fluid flow in a porous medium.

Snarsky (1982) (15) conducted different gravity segregation experiments on glass tubes that were filled with fine quartz sand. The porosity of that core was between 32% and 34% and a permeability of 9-11 Darcy. Vibration of 9 to 40 Hz was applied. It was observed that drainage was good between 9-10 Hz, decreased around 28-32 Hz and sharply increased again above 36 Hz.

A series of gravity segregation experiments where performed by Ashchepkov (1989) (16) on sandstone cores with permeabilities of 280, 350 and 650 mD. The core had a dimension of 1 cm in diameter and a length of 60 cm. Different frequencies of 30, 60, 100, 200, 400 Hz were applied with amplitudes between 0.6 and 0.4 μm. He observed a significantly faster imbibition of water and oil drainage during the sound exposure.

With a synthetic core made from quartz sand, which had a porosity of 33% and permeability of 9-11 Darcy, Pogosyan et al. (1989) (17) observed the results of vibration on the single-phase permeability and gravity drainage. They came to the conclusion that vibration increases the permeability and improves the drainage. Unfortunately they gave no further information about the frequency of the wave field that was acting on the core.

Simkin and Surguchev (1991) (18) conducted a number of gravity segregation experiments, oil-displacement and imbibition tests. For the segregation test a sandpack of 1 m length and a diameter of 3.5 cm was used, with a porosity of

33%, a permeability of 5.4 Darcy, the residual oil saturation was 0.5 and oil viscosity 1.65 cP. The core is put in vertical position and gravity equilibrium is established at the beginning of the experiment. Afterwards the core is turned over meassuring the time it takes until the liquids are segregated by gravity again. Without vibration it took ~12 days and with vibration of 120 Hz a new equilibrium was achieved after ~2 hours. For the oil displacement test a sandpack of 95 cm length, 35 cm width and 1 cm thickness was used. The porosity was 45% and the permeability 18-20 Darcy. Without vibration a 45% and with vibration a 75% oil recovery was measured. A sandstone core with 26 cm length and 3 cm diameter, with a permeability of 1 Darcy was used for an imbibition test. A recovery of 56% of the oil was observed after 325 hours without vibration and 96% oil recovery with vibration.

2.1.4 Field Studies

Numerous field studies have been carried out, to test the artificial generation of acoustic waves for stimulation. A lot of work has been done in the former USSR, but there are also successful reports of the application from other countries, including China, Canada and the USA. The first studies and applications date back as far as the 1950s and the first large scale field experiments were conducted in the 1960s (19).

To achieve similar stimulation results, as triggered by the natural occurrences, all kinds of different vibration methods were applied. They include:

1. periodic bumping of the surface by a large weight, which is similar to vibroseismic,
2. pulsed water injection, to generate water-hammer type waves,
3. sonic or ultrasonic generation directly in the wellbore,

4. generation of waves via explosions at the surface or downhole

Based on the observations that were made on the effect of waves on the productive behavior of water and oil wells, a new EOR method was developed which implemented the utilization of this phenomenon.

In Kyrgyzstan in the Changirtash oil field two field tests were conducted. The reservoir is at a shallow depth of 240-448 m, with a thickness of 4-10 m and it is dipped at 35°. The average permeability was 200 mD and the oil viscosity was 35 cP. The vibration source was a 50 kW surface vibrator, of which 2 were used and installed 20 m apart. The stimulation period was from October 5 until October 20, 1988. During that time 300 tons of additional oil was produced. The water cut was at 69% and it was decreased by 25-30% during the stimulation period. A second test at a deeper part of the reservoir (511-708 m) was carried out during December of 1988, during which time 2540 tons of additional oil was recovered. The test area included 16 producers (Kouznetsov et al., 1998 (20))

In the Pravdinsk oil field in Russia a field test was conducted using an electromagnetic vibration generator to produce low-frequency seismic waves of a frequency of 5-20 Hz. The reservoir depth is 2340 m with a pay thickness of 8 m, porosity was 20%, permeability at 104-117 mD and oil viscosity was 1.35 cP. The test was conducted in a watered-out section of the reservoir, where 39 producers and 27 injectors were located, but only 18 producers were in a 3 km radius which was estimated to be the range of the vibration device. The stimulation period was from September 17 to November 11, 1994. The oil production was recorded 8.5 months before, 2 months during and 7 months after the test was test was conducted. The results were not definite. For 13 wells it showed a positive behavior and for 5 wells quite the opposite was observed. The average water cut of the positively influenced wells was decreased from 91.9% to 83.3% while the average fluid production dropped slightly from 46.9 to 44.8 tons/day. The water cut of the 5 wells, which did not show any improvement, increased from an average of 85.1% to 88.1% and the average liquid rate increased from 30.6 to 36.4 tons/day. The effects of stimulation were noticeable for 7 to 12 months after the vibration was applied application (Simonov et al., 1996 (21))

Zhang et al. (1999) are reporting about on a field trial in 1993 where an artificial vibration source was used. The oil field is located in the western part of the Xinjiang province in China. A structure map of the stimulated block 1764 that was stimulated can be seen in Figure 5.

The reservoir is faulted and surrounded by a big fault. The block was put on production in 1961 and the first waterflood was conducted in 1975. The reservoir shows quite a high heterogeneity, which makes it difficult to perform an efficient water injection. Therefore the sweep efficiency is very low. Water fingering and uneven water front resulted in low oil recovery and increasing water cut. At the time of stimulation there were 5 producers, 2 injectors and 1 abandoned well. By the end of 1992 the oil recovery was at 17.2% (19).

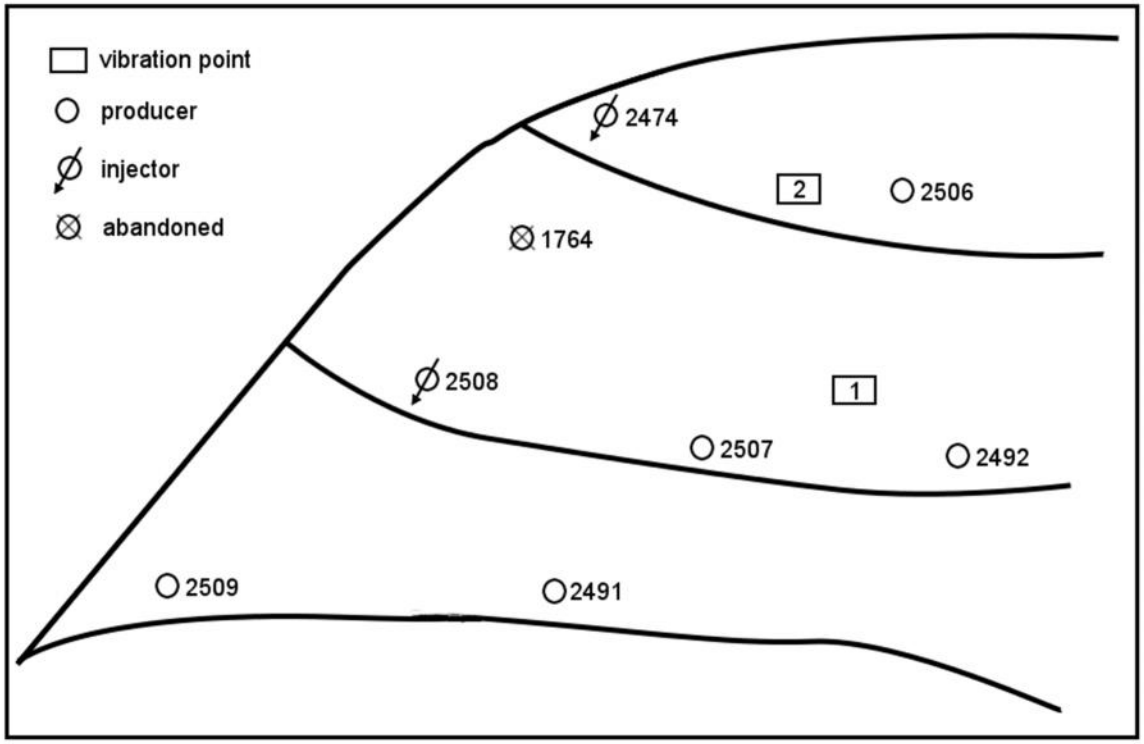

Figure 5: Structure map of part of an oil field in the west of Xinjiang province in China (19)

The stimulation of block 1764 was started in June 1993 and realized at two different positions in the field as can be seen in Figure 5. The unit was a 20 ton off-center vibrator with a maximum vibration force of 200 kN. The cumulative vibration duration for the first spot was 46 hours and 48 hours for the second location.

The incremental cumulative oil that was accounted as improvement by the vibrational stimulation amounted to 2233.26 tons (19) by the end of November 1993. After the two cycles all 5 production wells showed an increase in oil rate and a drop in water cut, one producer's liquid rate dropped by a moderate amount. Table 2 lists these results and additionally the depth of each well and the fluid level below well head. Remarkable is the increase of well number 2507, which showed an increase in average oil production from 0.58 m^3/day to 18.30 m^3/day. They concluded that a vibration period of 3-5 days is efficient to produce good effects and it is effective for generally 20-60 days. They further stated that artificial vibration leads to an increase in liquid and oil rate and a reduction in water cut, so it has the potential to improve the water drive efficiency and ultimate oil recovery. They also mentioned that artificial seismic production technique was not able to produce any formation damage and it is possible to remove plugging caused by other measures.

Table 2: Comparison of pre- and post-vibration parameters

Well no.	**2491**		**2492**		**2506**		**2507**		**2509**	
Depth [m]	598		542		491.6		527		593	
	Pre-vib.	Post-vib.	Pre-vib.	Post-vib.	Pre-vib.	Post-vib.	Pre-vib.	Post-vib.	Pre-vib.	Post-vib.
Average liquid production [m^3/day]	25.09	27.04	19.33	16.11	12.20	12.65	24.97	28.31	29.34	37.40
Water cut [%]	57.8	41.2	65.5	52.8	97.2	94.5	97.69	35.36	56.07	15.39
Average oil production [m^3/day]	10.58	15.88	6.67	7.59	0.35	0.69	0.58	18.30	12.89	31.64
Fluid level below well head [m]	299.0	343.1	223.0	159.0	159.1	160.3	227.8	253.8	304.4	To well head

Groeneboom et al. (2003) (22) are giving their observations about a stimulation of a heavy oil field in Germany in July 2002 for a total time of five months. They used a tool, which consists of a piston and a cylinder. The piston is raised and then dropped on its own weight, where the impact creates seismic waves. The field test was conducted in a part of the reservoir, where the viscosities of the oil ranged from 90-120 cP and an API gravity of 24.5. The stimulated layer is a weakly consolidated sandstone, which is faulted and dipping towards the southeast. The top depth ranges between 560-885 m, the thickness lies between 20 and 35 m which consists of two layers with a thickness of 10-20 m gross each and separated by shale. The reservoir porosity was between 20-30% with a permeability from 100 to 5000 mD. At the time of the stimulation about 25% of the STOIIP, or around 104 million tons of oil has been recovered. The main finding of the field observations was the increase in injectivity of the water injector while keeping the injection rate constant. The injection before the stimulation was stable just below 30 bar and three weeks after continuous stimulation it dropped to 11 bar. The pressure increased again over time. After the trial period the pressure stayed around 20 bar for about a month and started to rise again afterwards. Due to problems during the production recording process, it was not possible to evaluate if there was any increase in production. Their conclusion included that the increased injectivity would mean that the injection rate can be raised, which would improve the recovery rate and effectiveness of the waterflood pattern.

2.2 Hydropuls® Tool

The particular tool that is going to be used for acoustic stimulation for RAG oil field is called Hydropuls®. It has its origins in the field of water-well screen filter cleaning and was adapted by the manufacturer to work with the higher temperature and pressure conditions in oil wellbores. It fits a tubing with a minimum inner diameter of 2 7/8 inches.

The working principle for the generation of an impulse is achieved through a sudden expansion of highly compressed gas. This accumulated energy is released and causes the generation of hydraulic shock waves. Additionally the sudden change in volume causes the generation of a so called cavitation bubble, which is collapsing after a certain time and by that it creates a hydraulic suction wave (23). This effect causes the cleaning of the near wellbore zone from plugging particles.

The tool is deployed into the wellbore on a so called capillary string. That is a special form of coiled tubing, which is a continuous pipe wound on a spool. It is straightened before it is pushed into the borehole and depending on the diameter of the pipe different depths can be reached. The advantage to conventional piping is that there is no need to make connections, so the time consumption of the running-in-hole operation is vastly decreased.

There was also a test carried out in 2011 to assess whether the acoustic tool would have a negative impact on the cementation of casings. A test apparatus with a length of 3 m was used which consisted of two concentric steel pipes, the outer one was cemented in place with an inner diameter of 245 mm and the second pipe had an inner diameter of 125 mm. The wall thickness was 4-5 mm for both. A cement-bond-logging run was carried out before and after a pulsation period of around 30-40 minutes. It was assessed that there were no significant indications that the pulsation damaged or weakened the bond between the cement and the steel pipe (24).

2.2.1 Previous Applications by RAG

The Hydropuls® tool was tested in two separate field trials by RAG since it was modified for the application in oil fields.

The actual field names were replaced by names from the Greek alphabet, this was done due to the confidential nature of some of the data or maps within this thesis.

The first test was conducted in 2011 in the field *Alpha* for well *A-005*. The work schedule was to lower the acoustic tool to different depths and to a total depth of 2225 m and perform a pulsation period of one week altogether. To confirm the operational integrity of the device, a test on surface in a 20 m^3 cyclone tank was performed. Afterwards the actual field trial was conducted, the tool was lowered into the borehole and only after one triggered pulse a gasket was destroyed and the tool could no longer be used. After that first field test the device was redesigned.

The second field trial with a newly constructed tool was carried out in 2014 in the field *Tau* in the well *T-026*. At first the functionality of the device was tested on site in a 20 m^3 cyclone tank for several minutes. After a successful test-run the tool was lowered into the borehole on a capillary string. The pulsation device was operated at different working pressures. Before each new run in hole there was a surface test in the cyclone tank to assess the proper functionality of the tool.

The pictures in Figure 6 were taken during the second field trial in the field *Tau*. The left upper picture shows the deployment of the tool on a capillary string. The wellhead was modified too, so that the tool may enter the wellbore. The lower picture on the left hand side shows the cap string unit, were the tubing spool is installed and spooled off. The right picture shows the tool itself, which is lowered into the wellbore for stimulation.

Figure 6: Left upper picture shows the deployment of the tool on a cap string. The left lower picture shows the capillary string unit. The right picture shows the Hydropuls® tool itself.

2.3 Oil Recovery Improving Mechanisms

There are different reasons proposed to be responsible for the improvement in oil recovery by vibration, but nearly all of them are not backed up by experimental data or theoretical models of how the waves may influence the reservoir in a positive way.

The most common mechanisms that are mentioned in the literature are as follows:

1. Single oil droplets coalesce with one another and form larger oil droplets, which increases mobility and may become part of the flowstream (5) (6) (25)
2. Improved sweep efficiency of oil that has been bypassed due to reservoir heterogeneity (22)
3. Elastic waves may generate secondary high frequency wave, which can be as high as ultrasound (5) (25)
4. Vibration may induce crossflow between layers with different permeability (26)
5. Mobilization of capillary entrapped oil (27)

(1) A very important mechanism that has been suggested in different publications is the mobilization of entrapped oil by vibration. The postulated theory behind is that movement of the pore wall, due to excitation by acoustic waves, can dislodge trapped oil droplets and they coalesce into larger one and can therefore be moved as part of the flowstream through the reservoir, as seen in Figure 7. Besides the coalescence of oil droplets another possibility is that vibrational action of the acoustic wave acting on the reservoir break up the oil into sizes that are small enough that they can be moved through the pore ganglia.

(2) Based on laboratory observations that were published, another reason for the improved recovery of oil is the fact that the displacement of oil by a waterfront is stabilized during the application of vibration. It was noticed that when a core

was subjected to sonic waves there was a distinct reduction in viscous fingering (22), which means that injected water is moving a lot faster in parts of the reservoir where the permeability is higher than in other parts and therefore the displacing waterfront forms a finger-like interface. This means that the areal and vertical sweep efficiency may be improved and thus the recovery of oil increased.

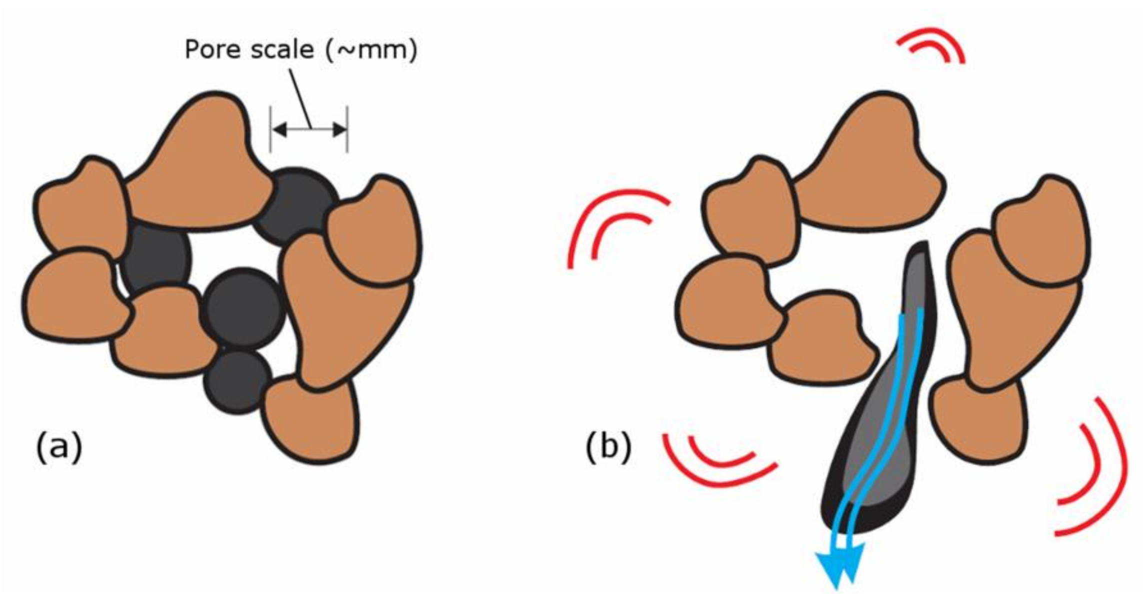

Figure 7: (a) Oil droplets are held in place and not able to be produced; (b) acoustic stimulation causes the pore walls to vibrate and droplets to coalesce (28)

(3) A different reason that might be responsible for the increased production efficiency is proposed to be the fact that elastic waves passing through the formation generate high frequency waves that may be in the ultrasonic spectrum. A possible reason for that is given by Nikolaevskiy et al. (1996) (25) that seismic wave cause grains of which the reservoir is built up, to initiate rotations and relative motions, this causes the particles to contact each other. Every time that happens waves in the ultrasound spectrum may be generated. This may lead to

other favorable mechanisms, which are beneficial for oil production. The ultrasonic radiation causes the reservoir fluids to heat up, which in term reduces the density, viscosity and surface tension (29).

(4) Another important possible mechanism of improved oil recovery is the generation of a transient pressure. Since injected fluids are entering highly permeable layers more easily, it is difficult to reach the less permeable zones and consequently the oil will not be displaced as efficiently in those parts of the reservoir. One acoustic wave after the other passes through the formation regardless of permeability. When the wave propagates through a heterogeneous reservoir the pore pressure response is unequal for layers with different permeabilities. This will in turn create a transient pressure difference and thus a crossflow between the layers, which will potentially squeeze out oil of zones that were previously not reached by injected water.

(5) As the reservoir is produced the saturation of water is increasing and the one of oil is decreasing, until the point of residual oil saturation is reached and the oil becomes immobilized in the form of isolated droplets or ganglia. This is due to the fact that capillary pressure is building up as narrow pore throats are encountered and therefore a larger differential force is necessary to move the fluid. If the external pressure gradient is lower than the capillary pressure, the system will stay in a static equilibrium. If the system is subjected to vibration the additional external oscillatory force may be enough to overcome the necessary threshold to push the fluid out of the pore channel.

3 Reasons for Acoustic Stimulation

In order to achieve and above all sustain an economic production, it is necessary to keep the well in a favorable condition. Over time there is a tendency that the well condition and especially the near-wellbore zone are deteriorating. To counteract that decline two different techniques are commonly used. The first possibility would be the use of acids to stimulate the well and the other would be hydraulic stimulation. Where fluids carrying special propants are pumped into formation above the fracture gradient, to open up small paths and then held open by the propants.

3.1 Chemical Stimulation

The first use of acids as a stimulation method for wellbores is very old and dates back to the 19th century. The first patent for acidizing was issued in 1896 (30). The idea behind this treatment is, generally speaking, to remove material that is hindering the flow of fluids through the reservoir. This can either be material that has already been in position or that has been induced during the normal operation of the well, which includes drilling, cementing and perforation, but also improperly designed stimulations can lead to inferior conditions as compared to the previous state. Even production on its own can cause deterioration in deliverability of a well. The treatments with acid can be separated into three different categories (31):

- Acid washing
- Matrix acidizing
- Fracture acidizing

The target of acid washing is to remove unwanted particles in tubulars and the wellbore, but not the formation.

In matrix acidizing the chemicals are pumped into the formation, below the fracturing pressure. This is done to remove damage or particles that can be dissolved in acid and are blocking the perforation paths or the connected pore network in the formation.

The third category is fracture acidizing where the chemicals are pumped above the fracture pressure of the formation with the intend to create fractures that are acting as a flow channel for the reservoir fluids.

Depending on the mineralogy of the reservoir there are different acids that are used to achieve the desired success. For carbonate acidizing the following acids are commonly used (31):

- Hydrochloric (HCL)
- Acetic (CH_3COOH)
- Formic (HCOOH)

When used in a carbonate reservoir the acids dissolve the matrix of the formation itself and create so called wormholes, which are conductive channels. For sandstone acidizing basically the same acids are used, not to dissolve any part of the rock, but to dissolve any plugging material that are either naturally occurring or migrating into the reservoir during well operations. Additionally to those three, Hydrofluoric (HF) acid is used. It is capable of dissolving siliceous minerals of which sandstone is made up. Due to the fact that HF is a very strong acid it is not used alone, but always in combination with other weaker acids. For instance if it is used in too high dosages, it may cause substantial sand production.

Because of the aggressive corrosive nature of some acids that are being used, it is necessary to use corrosion inhibitors. Their purpose is to protect the equipment against excessive corrosion damage.

Besides these preventative substances it is also common to use other additives in order to achieve certain results. Additionally necessary are iron control agents and water-wetting surfactants. Iron control agents are used to prevent solid precipitation of dissolved iron or other metal ions. Water-wetting surfactants are used to assist the cleanup of acid after the stimulation and will leave the formation water-wet, which will be beneficial for the flow characteristics of oil and gas. But also retarders are used to control the reaction speed of the acid so that a deeper penetration into the formation can be achieved.

The amount of necessary acid increases with the length of the reservoir interval that needs to be acidized, a rule of thumb states that for a standard HF/HCL sandstone stimulation between 1 m^3 and 1.8 m^3 (32) of acid should be used per meter. So for a long horizontal openhole section of over 500 m the amount of acid required is nearly 1000 m^3. Many acid jobs require not only the main stage of acidizing, but also several other stages to enhance the effect of the stimulation treatment. For instance very often there are so called preflush stages, where chemicals are pumped to flush formation brine and other fluids into the formation so that they do not come in contact with HF acid of a later stage, because this may lead to precipitation. Also the preflush stage is designed to remove any hydrocarbon deposits, which could cause problems. After the main stage, where the actual acidizing happens, there is a so called postflush stage. With the purpose of displacing the acid into the formation as well as dissolving any unwanted precipitation products of the acid rock reaction. An additional purpose of the postflush is to act as a buffer between the fluid that is used to pump down the chemicals and the stimulation acids.

The amount of liquids that are pumped is about the same for each of the stages. So in total there is a huge volume of acids and other chemical substances that are necessary for an effective stimulation job. It is therefore of the upmost importance to handle all the fluids that are used as carefully as possible to prevent any damage to the environment or any injuries of employees or other people.

3.2 Physical Stimulation

As an alternative to excessive use of acids to improve well deliverability it is possible to use acoustic stimulation to clean out the wellbore. Different tools are available to deliver vibrational waves to the reservoir and some of them also feature a significant cleaning effect of the near wellbore zone. Therefore the problem that is associated with the use of corrosive chemicals, namely that they can be dangerous for people, equipment and environment when not handled properly, can be eliminated. Another advantage of the acoustic tools is that they are either wireline or coiled-tubing conveyed, so they offer a much better zonal control which allows the precise placement at the desired interval. This is important if some intervals want to be avoided, for instance if they are water bearing. Especially when it comes to costs, acoustic stimulation may have the advantage over conventional stimulation methods and can therefore be a profitable alternative, in particular for old wells with marginal production, where large expenditures cannot be justified. Another advantage of that type of stimulation is the fact that it is possible to keep up the production while using the acoustic tool. Therefore, no lost production and no blocking particles that are mobilized while performing the job will be produced alongside with the reservoir fluids.

3.3 Combined Stimulation

There is also another possibility, which is to use both the chemical and the physical stimulation simultaneously. As previously mentioned, seismic vibration could enhance the cross-flow between high and low permeable zones (26). Therefore it could be used to deliver chemicals to the less permeable zones, which would otherwise not be the case, because if liquids are injected they are following the flow path with the highest permeability and therefore least resistance. This would not mean that chemicals are totally avoided, but used more efficiently in a smaller volume.

4 Selection of Candidates for Acoustic Stimulation

Based on the findings of chapter 2 this chapter is concerned with the selection of suitable candidates for the stimulation with seismic waves. The following selection parameters will be used to narrow down the candidates, which should give a list of possible wells with the most promising conditions for acoustic stimulation. Another consideration regarding possible candidates for the application of wave-based stimulation was the fact that Hydropuls®, the particular tool that is used by RAG, is new in the oil industry, it was previously used in water well screen cleaning. The tool has been modified for the requirements of deeper wells, where higher temperatures and pressures are to be expected, moreover the tool was redesigned regarding the working pressure. It is not fully tested in well conditions, so it would be advantageous to first use the device in shut in wells, were it can easily be deployed and retrieved if necessary without disturbing the normal operation. So there will be a recommendation for a normal operating injection well and also, if available, possible shut in wells in the vicinity of suitable producers.

4.1 Reservoir Parameter

The parameters for selection are as follows:

- The water cut should be high and above 80-90% (25) (33)
- The gas oil ratio should not be too high and below 400 Nm^3/m^3. If it is too high, that means that excessive amounts of gas will dampen the wave too quickly and reduce the penetration depth substantially (34). Also the

application of seismic waves showed significant degassing of the reservoir fluids (6) which leads to an increase in oil viscosity and would make it more difficult to produce it.

- The higher the heterogeneity of the reservoir the better. Because in that case chances are that significant amounts of oil are left behind in a less permeable part of the reservoir and could be reached with wave-based stimulation. (22) (26) (35) (36)

- Consequently that means that the residual oil saturation should be high (25)

Another very important criterion is the fact, that the stimulation method has the potential to mobilize sand (22) and therefore should not be used on poorly consolidated sandstones, to avoid sand production, which poses a risk to the equipment installed, because of excessive wear and special measurements must be taken to handle the sand.

4.2 Selection of Oil Fields

The first preliminary selection of oil fields was made solely based on the number of wells with a water cut in the range of over 80%. The following Table 3 gives an overview of fields with wells categorized into 70%, 80% and 90% water cut. The number of wells with 70% and higher was also included, because even though lower than mentioned in the literature, a marginal effect is also possible.

Prior to that selection, there is another parameter applied, which is the consolidation of the reservoir. When considering that, two fields are containing sandstones layers with a weak consolidation and would therefore yield the risk of sand migration and fines mobilization. Therefore those two fields are eliminated beforehand.

Table 3: Number of wells in a particular field categorized into 70%, 80% and 90% water cut

Field	Number of wells			Notes
	>90% WC	>80% WC	70% WC	
Tau	4	1	0	
Beta	3	1	0	
Psi	1	1	2	
Iota	1	0	2	
Mu	1	0	0	GOR too high
Rho	1	0	0	
Nu	1	0	0	
Lambda	1	0	0	
Eta	1	0	0	
Xi	0	0	1	
Omicron	0	0	1	

At a first glance *Beta* and *Tau* show the most promising characteristics with 4 and 3 wells respectively with a water cut of over 90%.

When looking more closely at *Psi* one can see that the well in the second category (>80%) is only just below 90% and in the third category a well is just below 80% and a second one, which is a little above 70%, but with a net rate of 6 m^3/d.

The well located in the field *Mu* cannot be considered as a candidate for acoustic stimulation, because the GOR is too high (~13,900 Nm^3/m^3).

The field *Rho* contains only one well which is mentioned in Table 3 but with a rather high oil net rate (10 m^3/d).

Nu, *Lambda* and *Eta* have each one well with a water cut of over 90%, but they are showing rather low oil net rates.

The field *Iota* has two wells with a water cut of around 75%, but the net rates are rather low.

The field *Xi* contains one well, that would fit the selection parameter, but the net rate is rather low.

Omicron contains one well with a rather high net rate of ~15 m^3/d but the water cut is 71% which is on the lower end of the selection criterion.

The following fields are still in the discussion and more parameters will be considered for a closer selection:

- Tau
- Beta
- Rho
- Psi
- Iota

Since some of the pumping equipment that is used in electric submersible pumps (ESP) are sensitive to vibration the acoustic stimulation tool will only be used in injection wells. Another reason for that placement is the cleaning effect of the near wellbore zone. Since injected water usually contains small particles (an analysis about the solids content in the injection water can be found in the appendix) that is plugging the pores and thus decreasing the injectivity of the well a stimulation job needs to be done regularly. A very important additional reason for the use in an injector well is the cost effectiveness. If the tool would be used in a production well, it would be necessary to install a dual completion, so that the stimulation tool could be used alongside the pump. To install a new completion it is required to perform a workover job, which is a very costly procedure. When the tool is used in an injection well, the only prerequisites are a few modifications to the wellhead, which can be done in a very cost effective way.

To find possible injection well candidates it was assumed that the penetration depth of the acoustic wave is between 1500 and 2000 m.

4.2.1 Acoustic Attenuation

The acoustic attenuation was calculated with the following equation:

$$A(x) = A_0 \cdot e^{-\frac{2\pi f x}{2cQ}}$$

where:	Q	Attenuation rock quality factor	Empirical value: 57 (37)
	f	Wave frequency	100-200 Hz[1]
	c	Wave speed	4000-4300 m/s[2]
	A_0	Wave amplitude at origin	

Figure 8 shows the attenuation of the seismic wave, utilizing the aforementioned equation. It is important to keep in mind that this is the case for an idealized reservoir, where no substantial attenuation due to heterogeneity is happening, so for a real case scenario a lower remaining energy has to be expected.

[1] Working frequency range of the acoustic stimulation tool that is used by RAG
[2] Typical speed of primary wave velocity for sandstone reservoirs according to RAG geophysical department.

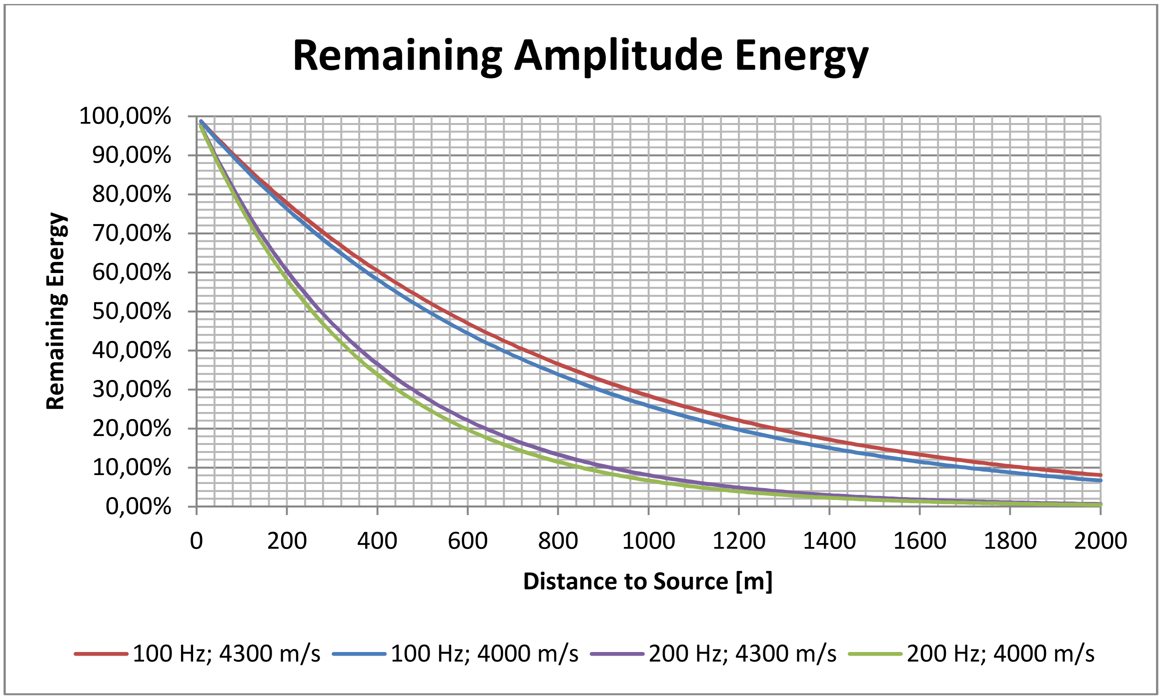

Figure 8: Attenuation of the seismic wave within a typical RAG sandstone reservoir. Showing remaining energy vs. distance to source.

The abscissa shows the distance to the source of the acoustic tool. The ordinate gives the calculated remaining energy of the wave. At a distance of 0 m to the source the remaining energy is at 100%, which means this is the origin amplitude. With increasing distance, the amplitude is decreasing as the wave is attenuated while travelling through the porous medium. The graph in Figure 8 shows four lines in total, each line represents a different frequency and primary wave speed. The upper two lines (red and blue) show the attenuation for a wave with a frequency of 100 Hz, the first one represents the case where a primary wave speed of 4300 m/s is assumed and the second one where the speed is 4000 m/s. It can be seen, that for a rock with a higher primary wave velocity the attenuation is lower, and thus the red line is above the blue line. The lower two lines show the case with a wave frequency of 200 Hz. At a first glance it can easily be seen, that the attenuation is much higher than for the case with 100 Hz. The first of the two lines (purple) shows the higher primary wave velocity of 4300 m/s the second line (green) shows the lower velocity of 4000 m/s.

When looking at the graph at a distance of 1000 m, the remaining energy of the wave for the case of 100 Hz is around 25% (28.4% and 25.8% for a primary wave velocity of 4300 m/s and 4000 m/s respectively). In the case of a frequency of 200 Hz the wave would already be attenuated to around 7% remaining energy (8% and 6.7% for a velocity of 4300 m/s and 4000 m/s respectively). This is already a strong attenuation for a moderate distance of 1000 m. When looking at a distance of 2000 m from the wave emitting source, the remaining energy for the case with 100 Hz is around 7% (8% and 6.7% for a velocity of 4300 m/s and 4000 m/s respectively) which is the same as for a distance of 2000 m and a frequency of 200 Hz. When looking at the remaining energy of the wave in the case of 200 Hz and a distance of 2000 m one can see that it is already below 1%.

4.3 Tau

As already mentioned the field *Tau* contains four wells that meet the requirements of a high water cut. The next important step is now to find the best fitting injector that is in an ideal distance to the producers that are meeting the requirements.

4.3.1 Production Data

Table 4 shows the latest production data of the field *Tau*. When looking at the gas rates some wells show a significant gas production. Since excessive amounts of gas will dampen the wave too quickly it is important that the gas oil ratio (GOR) is below a certain value, which should not be higher than 400 Nm^3/m^3 (34). The GOR for well *T-030* is slightly above the mentioned upper limit, but with 431 Nm^3/m^3 not too high. Well *T-007* on the other hand shows a very high GOR with around 8,700 Nm^3/m^3, which will decrease the penetration depth of the tool substantially. So this well is eliminated from the lists of candidates.

Table 4: Detailed production data for the oil field *Tau*

Well	Test-Date	Gross [m^3/d]	Net [m^3/d]	H2O [m^3/d]	WC [%]	Gas [Nm^3/d]	GOR [Nm^3/m^3]
T-030	01.07.14	273.0	2.5	270.5	99.1	1,060	431
T-033	20.07.14	211.9	2.3	209.6	98.9	780	335
T-015-C	01.05.14	214.6	4.7	209.9	97.8	850	180
T-007	20.05.14	7.9	0.5	7.4	93.6	4,400	8,696
T-013-A	01.08.14	20.0	3.0	17.0	85.0	960	320

Three wells (*T-030*, *T-033* and *T-015-C*) are showing a very high water cut, which should be a good prerequisite (33) for acoustic stimulation. The well *T-013-A* shows a lower water cut, but still in the mid-80s range and a GOR of 320 Nm^3/m^3, so also a potential candidate which could show a production increase when wave-based stimulation is performed in the vicinity. A graphical display of the production history of the four wells (*T-030*, *T-033*, *T-015-C* and *T-013-A*) can be found in the appendix.

4.3.2 Geological Map

The next step in finding the best fitting injector for the field *Tau* is to look at their relative position to each other and measure the distance to the next injector. Therefore it is necessary to take a look at the geological map, which can be seen in the Figure 9 below. The well *T-013-A* is not pictured, because it is approximately 5 km to the west of *T-033*. The other three possible candidates are within range of 2 km. When looking at the geological map one can see that the wells *T-015-C* and *T-033* are close by a fault, which has been reported (12) to have a positive impact when using wave-based stimulation.

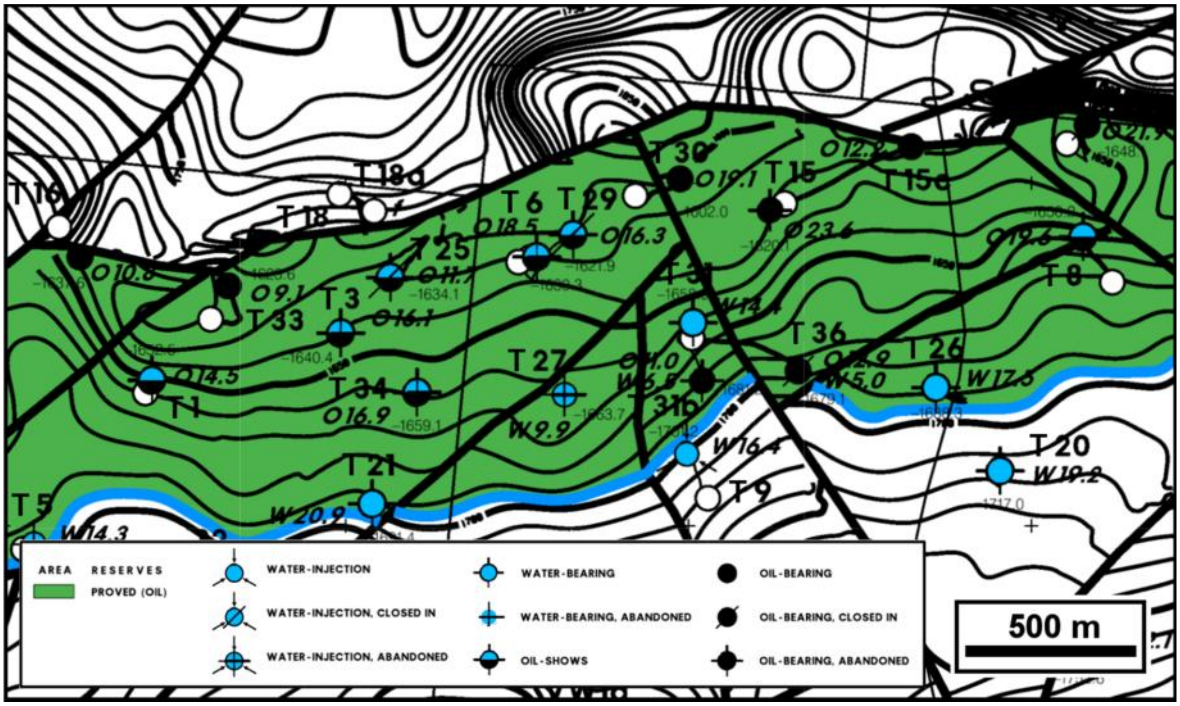

Figure 9: Geological map of eastern part of the *Tau* oil field of the Cenomanian sandstone layer. Not pictured in her is well *T-013-A*, which is around 5 km to the west of *T-033*

Taking a closer look at the completions of the wells of interest, it can be observed, that all of them show perforations in the Cenomanian sandstone layer. Therefore, it is necessary to find a well candidate which has perforations in the same layer so that the stimulation tool can be used most efficiently. The following wells are currently shut in and thus can be considered for an application of the device:

- T-002
- T-009
- T-011
- T-016
- T-017-A

- T-025
- T-026
- T-029
- T-036
- T-039

T-009 shows perforations in the Cenomanian layer and lies in an ideal distance to the production nominees. The wells *T-016* and *T-017-A* are too far away to pose a possibility that the stimulation tool can be used. All the other wells do not have perforations for the interval in question and can therefore not be used for the purpose of stimulation.

The distances between the *T-009* and the other wells (*T-015-C*, *T-030* and *T-033*) are as follows:

- *T-009 → T-015-C: 1115 m*
- *T-009 → T-030: 800 m*
- *T-009 → T-033: 1425 m*

This well would be a very suitable candidate in terms of distance, since the maximum is below 1500 m. Therefore, it would be ideal to use for a trial period, to examine the tool and its causing effect more closely.

When taking a closer look at the injectors in the field *Tau* the following wells are currently in use for that purpose:

- T-005-B
- T-008
- T-022
- T-037

The wells *T-005-B* and *T-022* are too far away (with distances between 1500-3200 m and 1600-3600 m respectively). *T-008* and *T-037* both show perforations in the Cenomanian layer. The distance of *T-008* to the other wells are as follows:

- T-008 → T-015-C: 550 m
- T-008 → T-030: 1180 m
- T-008 → T-033: 2500 m

The first two distances are below 1200 m which is close enough. The third one (to *T-033*) on the other hand is at a distance were the acoustic wave is subjected to severe attenuation and therefore, would possibly be too far to expect any significant impact. The second injector under consideration (*T-037*) shows the following distances:

- T-037 → T-015-C: 2850 m
- T-037 → T-030: 2150 m
- T-037 → T-033: 840 m

As can be seen above two producers (*T-015-C* and *T-030*) are at a distance of over 2000 m and only one well is within 1000 m. So when comparing *T-008* and *T-037* in terms of distance, the first injector is clearly the better choice. When looking at Figure 8 it shows that the remaining energy at 2000 m is already calculated to be less than 10%.

4.3.3 Injector T-008

The current completion of *T-008* can be seen in the appendix.

Since the stimulation tool, that is going to be used, should also have an impact on the near wellbore zone in terms of cleaning, it could be interesting to compare the previous stimulation jobs with the following increase in injectivity afterwards and a possible change in injection rate and pressure after the wave-based stimulation.

The well *T-008* was used as a producer until September 2009 where it was re-completed as an injector. Since then it was stimulated once with an acid job in 2010.

4.4 Beta

The next oil field for closer examination is *Beta*. The field contains 3 wells with a very high water cut of over 90% and one well with a water cut of 83%.

4.4.1 Production Data

The detailed production data of the 4 wells under consideration can be seen in Table 5. When looking at the GOR of the candidates, it can be observed that it is lower than for the previous oil field under examination (*Tau*). The highest value is 136 Nm^3/m^3 which is well below the value proposed in the literature of 400 Nm^3/m^3 (34).

Table 5: Detailed production data for the oil field Beta

Well	Test-Date	Gross [m^3/d]	Net [m^3/d]	H2O [m^3/d]	WC [%]	Gas [Nm^3/d]	GOR [Nm^3/m^3]
BE-W-001	18.07.14	133.0	1.5	131.5	98.9	199	136
BE-W-002	06.08.14	134.2	2.0	132.2	98.5	133	66
BE-001	27.07.14	267.0	13.4	253.7	95.0	750	56
BE-004	23.07.14	2.3	0.4	1.9	83.0	0	0

What is additionally noticeable that the well *BE-001* which shows, compared to the other wells and also all wells previously listed in *Tau*, a rather high oil rate of 13.4 m^3/d. The other three wells show moderate to low net rates, especially well *BE-004* has a very low net rate of 0.4 m^3/d. So the focus will lie on the one particular high producer, to find the closest injector which is as close by as possible. Additionally, the producer is only perforated in an upper section and not the same layer as the other wells nearby especially the injector, so it will not be considered as a possible candidate. A graphical display of the production history of the four wells in question can be found in the appendix.

4.4.2 Geological Map

To find the right injector in the field *Beta* the next step is to look at the geological map keeping in mind to look for a candidate that is as close to well *BE-001* as possible, because of its high oil rate. Figure 10 shows the geological map of the upper Eocene sandstone layer in *Beta*, it is important to be noted that it is based on 2D seismic and therefore rather coarse and less accurate than a map that would be based on a 3D seismic.

It can be seen that, except for well *BE-W-002*, all wells are located near faults. Further it can be observed that all wells are in a close window when considering the distance. All four wells of interest have perforations in the Eocene sandstone layer, so it is necessary to look out for an injector with the same perforation interval. Since there are no shut in wells at the moment in *Beta* the selection is limited to injection wells. The following wells are currently injecting water in the field:

- BE-003
- BE-005

The well *BE-003* has perforations in the Eocene and the Cenomanian sandstone layer and has the following distances to the producers under investigation:

- BE-003 → BE-W-001: 1150 m

- BE-003 → BE-W-002: 965 m
- BE-003 → BE-001: 910 m

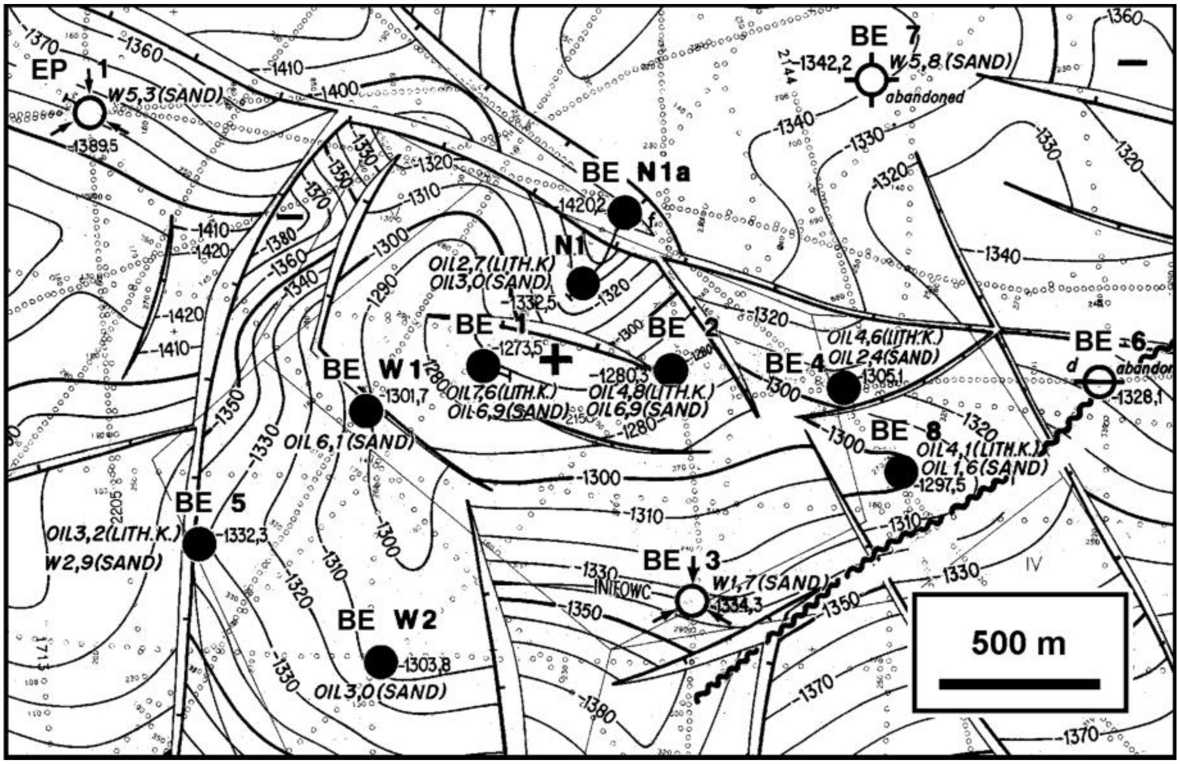

Figure 10: Geological map of the oil field *Beta* of the upper Eocene sandstone layer.

The three wells are within a distance of 1000 m and only one of them is above the one kilometer mark. Therefore, when considering the calculated attenuation of the wave as seen in Figure 8, it shows that *BE-W-001* has an ideal distances to the producers that are most likely to show a production increase when stimulated with an acoustic tool.

The other injector in the field *Beta* (*BE-005*) is also perforated in the Eocene interval and lies at the following distance to the producers:

- BE-005 → BE-W-001: 660 m
- BE-005 → BE-W-002: 670 m
- BE-005 → BE-001: 1060 m

Two wells are in close proximity to this injector and the well with the highest production in the field (*BE-001*) is also at a distance of just above 1000 m.

Figure 11 shows the cross section of the Eocene sandstone of the oil field *Beta*. Since acoustic waves are attenuated when reaching and going through a fault (38) it is important to keep this in mind, when looking at the distances between injector and producer. It can be seen in Figure 11 that there are some faults located between the injector *BE-005* and two of the candidate producers that are pictured (*BE-W-1*, *BE-001*).

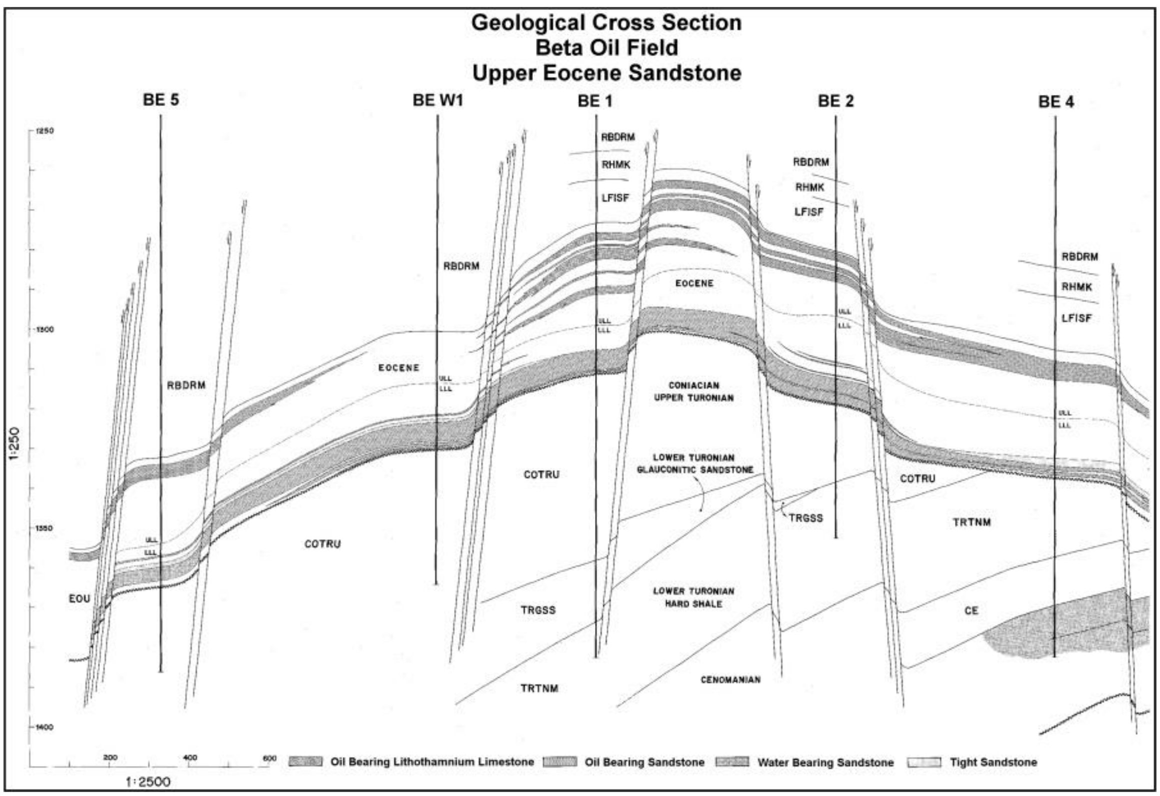

Figure 11: Cross section of the upper Eocene sandstone layer of the oil field *Beta*

When considering the injector *BE-003* and checking its location on Figure 10 and drawing a mental connection line to the producers *BE-001* and *BE-W-1* it can be seen that there are no faults lying in between. In fact the faults are running more or less parallel to that mental connection line. Therefore, the injector BE-003 would be an excellent candidate for the usage of a stimulation tool.

4.4.3 Injector BE-003

The current completion of *BE-003* can be seen in the appendix.

BE-003 was drilled in end of 1979 with the purpose of increasing the production of the nearby wells by injecting water into the formation. Since then it was stimulated in 2004, 2007, 2009 and 2011 by an acidizing job in order to increase the injectivity and also the efficiency.

4.5 Rho

The field *Rho* contains only one well with the required high water cut. Additionally there is one active producer, but with a lower water cut of 66%.

4.5.1 Production Data

The latest production data for the field *Rho* can be seen in Table 6. Only one well (*RH-005A*) meets the required water cut. The other listed well is the other active producer in the field. When checking the GOR it can be seen that it is low and should not pose a problem for wave-based stimulation.

Table 6: Detailed production data for the oil field *Rho*

Well	Test-Date	Gross [m^3/d]	Net [m^3/d]	H2O [m^3/d]	WC [%]	Gas [Nm^3/d]	GOR [Nm^3/m^3]
RH-005A	01.07.14	182.8	9.5	173.3	94.8	126	13
RH-006A	01.07.14	3.6	1.2	2.4	66.0	5	4

The oil rate for *RH-005A* is slightly below 10 m^3/d, which is rather high when compared to the other wells in the previously discussed oil fields. Since well *RH-006A* shows a low water cut and also a lower oil rate it may not be a promising candidate. The production history of the wells can be seen in the appendix.

4.5.2 Geological Map

There is only one injector in *Rho*, which is *RH-001*. Concerning the distances in the field it can be observed that they are rather small, which are optimal conditions for the wave. The spacing between the injector and the producers are as follows:

- RH-001 → RH-005A: 480 m
- RH-001 → RH-006A: 370 m

These are very good numbers and the shortest maximum distance so far.

There are no current geological maps of *Rho* available therefore, no overview of the relative well positions can be obtained however, the cross section seen in Figure 12 is sufficient to obtain an insight into the reservoir. Both producers are perforated in the Eocene sandstone interval, as is the one injector in the field *Rho* which is *RH-001*. When taking a closer look at the Figure 12 it can be seen that between the injecting well and the producer *RH-006A* is no structural obstacle that would diminish the wave substantially. The more promising candidate, in terms of water cut and oil rate, *RH-005A* on the other hand is separated from the injector by a fault structure. This could mean a significant attenuation of the wave.

There is one well in the field that is currently shut in (*RH-008*). When looking at Figure 12, it is located, between the well *RH-006A* and the injector *RH-001*. This would be even closer to the two following producers:

- RH-008 → RH-005A: 290 m
- RH-008 → RH-005A: 180 m

These are excellent distances and when considering the attenuation calculations displayed in Figure 8 this would mean it is possible for a wave with a high remaining energy level to reach the producing wells. The depth on the vertical axis in Figure 12 is given in TDSS (True Vertical Depth Subsea).

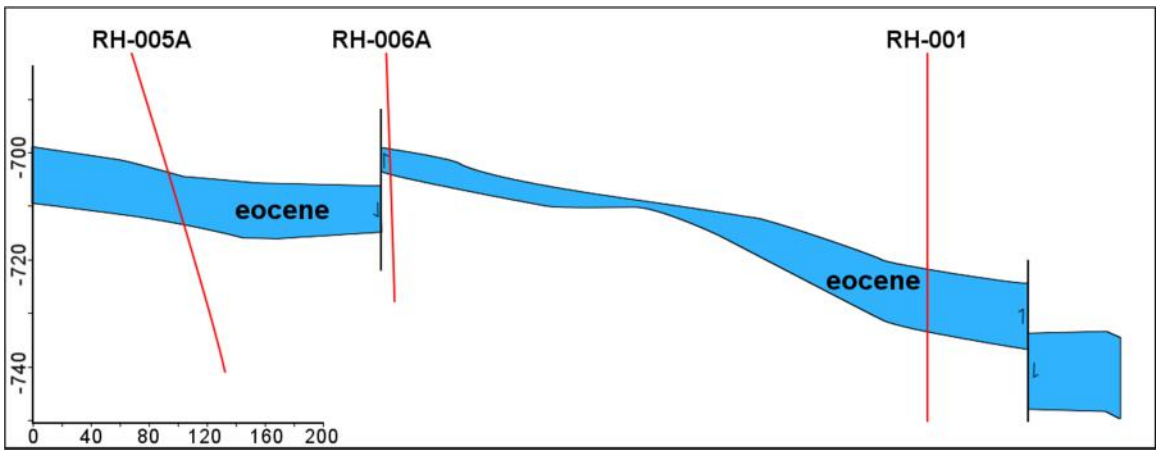

Figure 12: Cross section of the Eocene sandstone layer in the oil field *Rho*

The well *RH-008* was shut in due to a very low oil rate and very high water cut which results in uneconomic production, however, the pumping equipment is still installed in the borehole. In order to enable the application of the acoustic stimulation tool it would be necessary to perform a workover. Nevertheless if the wave-based stimulation device would be used in the injector *RH-001* the production of well *RH-008* could be positively influenced in a way that it could be resumed in an economic region.

4.5.3 Injector RH-001

The current completion of *RH-001* can be seen in the appendix.

RH-001 was drilled in 1968 as a production well. Oil with light amounts of gas was encountered in the Eocene at a depth of around 1060 m. Gas was encountered in the Haller Serie which is at a lower depth of around 360 m. The oil production ceased in 1986 and the well was shut in. In 2004 there was an injection test to examine whether the well could be used as a disposal well for formation water. It was stimulated by an acid job in 2010 and then used to reinject produced water from the surrounding wells in the field *Rho*.

4.6 Psi

There are 4 wells located in Psi that are meeting the requirements of a water cut of over 70%. There is one well with a water cut of slightly above 90%, one well in the high 80s and two wells in the middle of the 70% to 80% range.

4.6.1 Production Data

A more detailed overview of the latest production data of the 4 candidate wells can be seen in Table 7. When taking a closer look at the GORs it can be seen that they are well below the critical value of 400 Nm^3/m^3 (34). Compared to the previously discussed fields the oil rates of the 4 candidates are, located in the lower to mid-range. Only well *PSI-023* has a higher production of nearly 8 m^3 of oil per day. This will be considered when selecting the right application well for the stimulation tool. The production history of the 4 wells mentioned in Table 7 can be seen in the appendix.

Table 7: Detailed production data for the oil field *Psi*

Well	Test-Date	Gross [m^3/d]	Net [m^3/d]	H2O [m^3/d]	WC [%]	Gas [Nm^3/d]	GOR [Nm^3/m^3]
PSI-008	16.07.14	12.6	1.2	11.4	90.6	190	160
PSI-006	09.07.14	26.4	3.2	23.2	87.7	325	100
PSI-010	25.07.14	4.3	0.9	3.4	78.2	50	53
PSI-023	17.07.14	33.2	7.7	25.5	76.8	660	86

4.6.2 Geological Map

There is one active injector in the field *Psi* which is *PSI-022A*. When looking at the distances between the producers and the injector the following results can be measured:

- PSI-022A → PSI-006: 750 m
- PSI-022A → PSI-008: 690 m
- PSI-022A → PSI-010: 880 m
- PSI-022A → PSI-023: 725 m

All of the above values are below 1000 m and therefore in a good range of a possible stimulation with the wave-based tool.

Figure 13 shows the geological map of Eocene sandstone layer in the *Psi* oil field. The well *PSI-008* has a direct path to the injector with not fault in between, all the others are structurally separated to some extent.

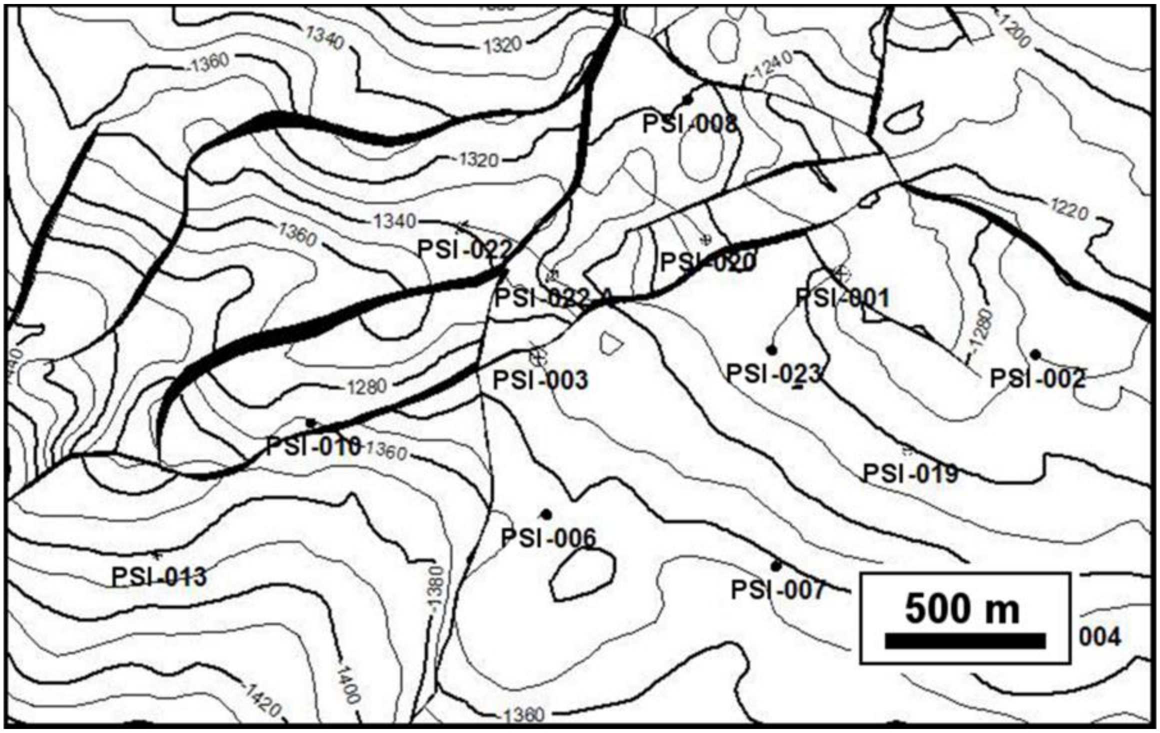

Figure 13 Geological map of the oil field *Psi* of the Eocene sandstone layer.

The cross section in Figure 14 gives an insight into the structure of the Eocene in that area. All producers have perforation intervals in the Eocene as is the case for the injector *PSI-022A*. On the cross section in Figure 14 the injector can be seen in the middle and that no faults are located between it and the producer *PSI-008*. The well *PSI-010* on the left side in the picture is separated by a fault from the injector. The strongest producer among the candidates (*PSI-023*) is located southeast of the injector, but not pictured in the cross section. The depth in Figure 14 is given in TVDSS.

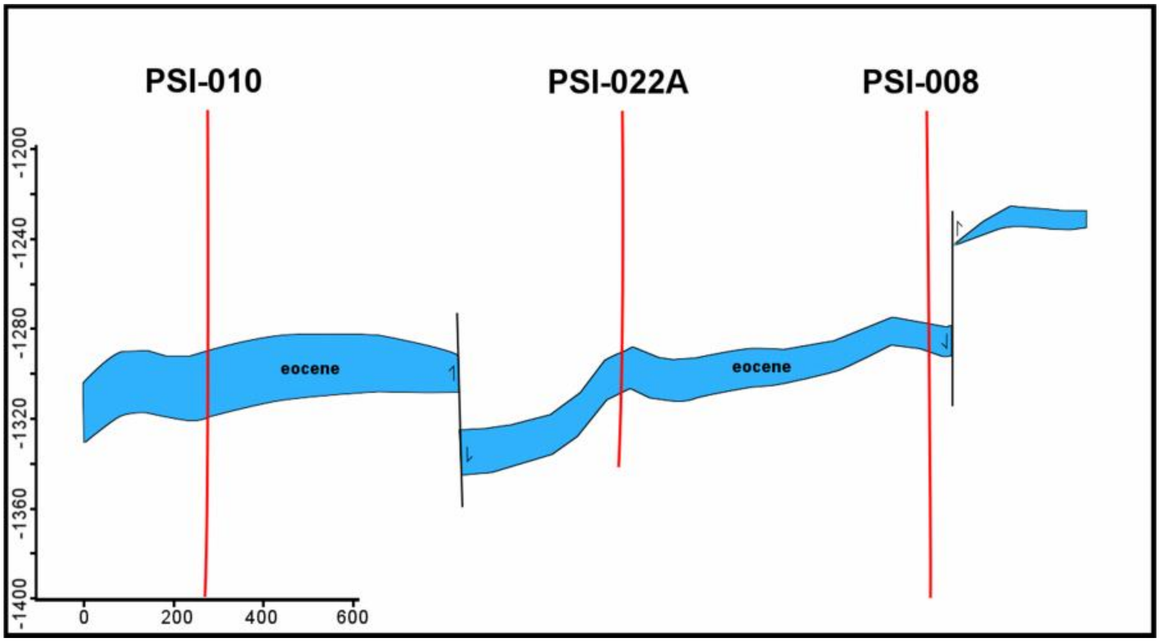

Figure 14: Cross section of the Eocene sandstone layer in the oil field *Psi*

There is one shut in well (*PSI-001*) in the field *Psi* which could be used to deploy the stimulation device. The perforations however are not accessible in the Eocene interval, so the tool could not be deployed to the necessary depth and therefore not used in that well.

In Figure 15 a populated porosity distribution map for field *Psi* can be seen. Since porosity and permeability are to some extend correlated to each other it is possible to see where less permeable areas in the field *Psi* are to be expected. It can be seen that the wells *PSI-010* and *PSI-023* are located in an area of higher porosity and hence, permeability. On the other hand the producers *PSI-008* and *PSI-006* are located near an area with less porosity and therefore permeability.

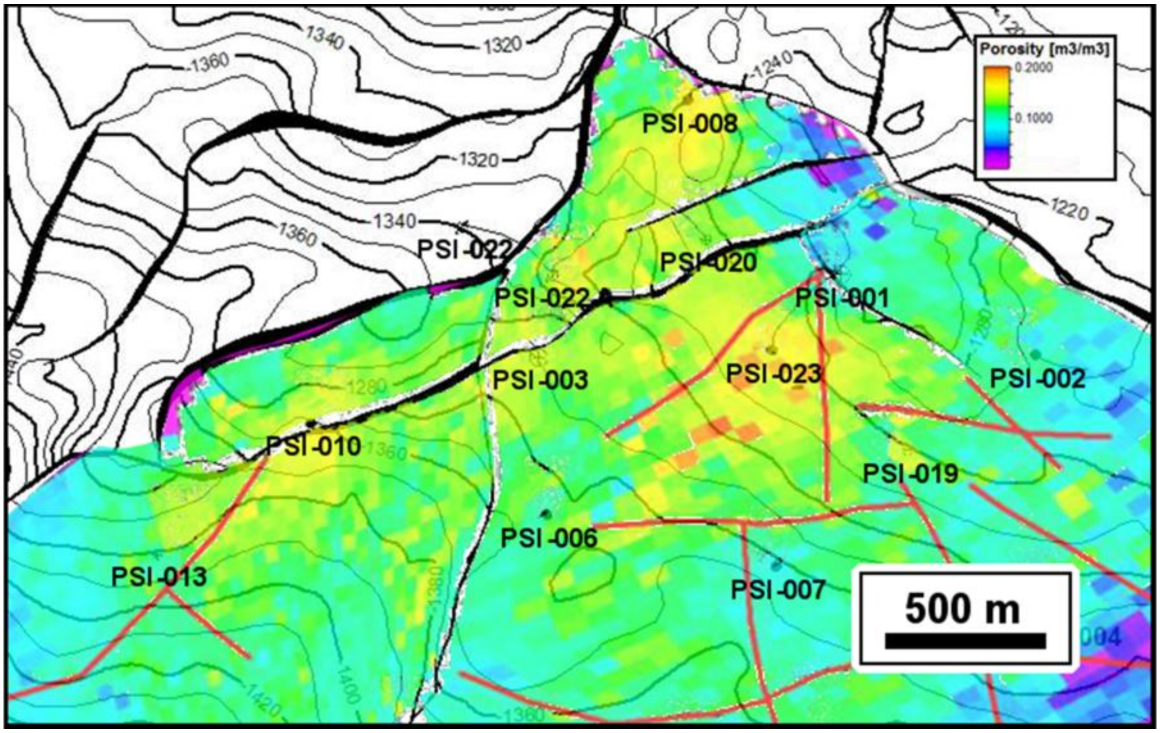

Figure 15: Populated porosity distribution map for field *Psi*

4.6.3 Injector PSI-022A

The current completion of the injector *PSI-022A* can be seen in the appendix.

The well was drilled in 1984 as a producer, but after testing it was established that is was in the same reservoir unit as *PSI-008* and to not lower the reservoir pressure even further it was completed as a injector to increase the oil recovery. In the recent years it was stimulated in 2004 and 2014.

4.7 Iota

The field *Iota* has five active producers. *IOTA-006* is the only one with a water cut of over 90%, but with a very low oil rate. Two additional wells are in the range between 70% and 80%, one with a moderate and the other with a very high oil rate respectively. The fifth well shows a water cut of slightly above 60% and a moderate oil rate as well.

4.7.1 Production Data

The detailed latest production data can be seen in Table 8. The GOR of all wells are below 100 Nm^3/m^3, except for *IOTA-006* where it is almost as high as 400 Nm^3/m^3.

Table 8: Detailed production data for the oil field *Iota*

Well	Test-Date	Gross [m^3/d]	Net [m^3/d]	H2O [m^3/d]	WC [%]	Gas [Nm^3/d]	GOR [Nm^3/m^3]
IOTA-006	06.08.14	6.2	0.1	6.0	98.2	42	378
IOTA-001	01.07.14	137.0	28.6	108.4	79.1	1.450	51
IOTA-004	14.07.14	29.4	7.9	21.4	73.0	280	35
IOTA-002A	04.07.14	22.0	8.1	13.9	63.0	570	70

The strongest producer in the field is *IOTA-001* with an oil rate of nearly 30 m^3/d, which is very high when comparing to all the previously mentioned wells. Additionally, two other wells in the field show a good rate of around 8 m^3/d. A graphical presentation of the production history of the wells mentioned in Table 8 can be seen in the appendix.

The injector *IOTA-005* was hydraulically stimulation in 2008. So there is a chance that the waves from the stimulation tool could mobilize the propants which are in place to hold open the fractures. This means that this particular injector cannot be considered as a possible candidate for the application of the wave-based device.

4.7.2 Geological Map

Besides the before mentioned injector, there is one additional located in the field *Iota* (*IOTA-003b)*. The geological map can be seen in Figure 16.

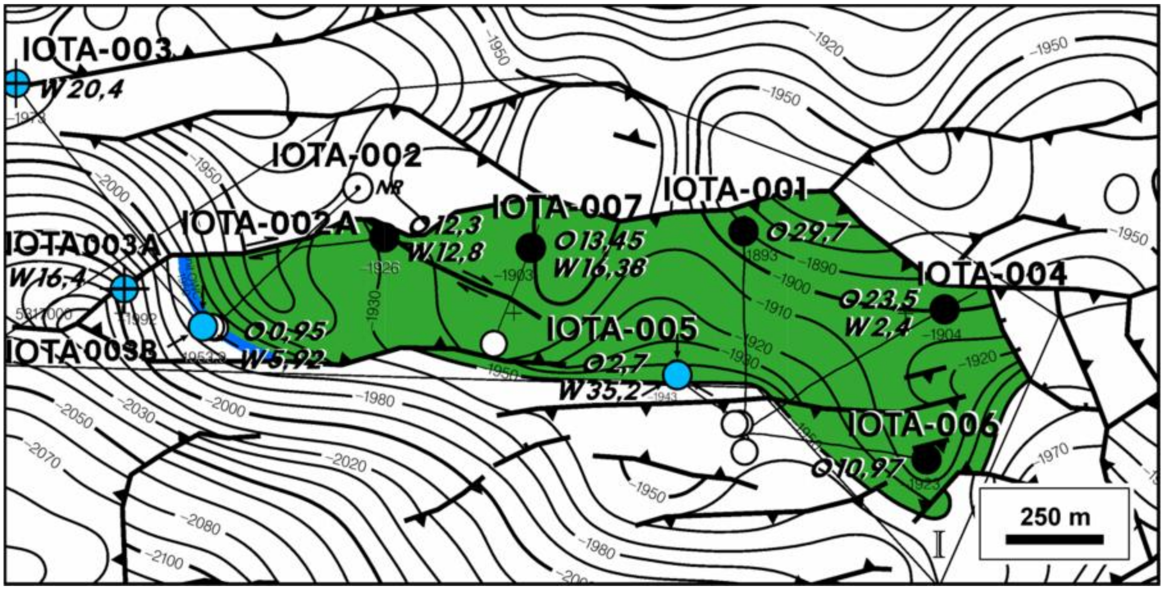

Figure 16: Geological map of the Eocene in the oil field *Iota*

Considering the distances between the producers and the injection well, only *IOTA-002a* is in a close enough range for an efficient application of the acoustic tool. The following spacing can be measured for the individual production wells to the injector:

- IOTA-003b → IOTA-001: 1405 m
- IOTA-003b → IOTA-002a: 520 m
- IOTA-003b → IOTA-004: 1900 m
- IOTA-003b → IOTA-006: 1885 m

Only one well is in a range of around 500 m, all other producers are at a distance of over 1000 m, the two farthest are nearly 2000 m away. Besides the spacing it can also be observed that all producing wells are located nearby a fault, which was indicated in the literature to be beneficial when it comes to an increase in production by acoustic stimulation. (12)

4.7.3 Injector IOTA-003b

The current completion of *IOTA-003b* can be seen in the appendix, when looking at it more closely, it can be observed that a tubing with an inner diameter of at least 2 7/8 inch was only used until a depth of 1608 m from that point onwards a tubing with an inner diameter of 2 3/8 inches was built-in. So the stimulation tool could not deployed to a depth where the perforations are located and therefore it would not be efficient to use the tool in that in injector.

The motherbore *IOTA-003* was drilled in 2008 and sidetracked into *IOTA-003b* and planned as an injection well for the field *Iota*. It was stimulated once in 2009 to increase the injectivity and enhance the efficiency.

5 Conclusion and further Recommendations

Since technology driven innovations are the backbone of an efficient and stable oil production it is very important to utilize it for a maximum efficient operation. Numerous articles in the scientific community are reporting about the potential of wave-based stimulation and that it is also an environmentally friendly procedure which today is considered more important than ever. It has also been mentioned in the literature that the outcome of the stimulation cannot be predicted precisely. Therefore, it is not possible to provide one single answer to the question which field is best suited to be stimulated, but rather a list of possible candidates.

The fields were chosen by certain guiding parameters that are mentioned in the literature. The main deciding criterion was the water cut, which should be high in order to see an oil production increase due to acoustic stimulation. Another important factor was the distance between possible wells where the device could be used, and the producers, which were selected. Due to reasons of cost effectiveness, only injection wells and shut in wells were considered to serve as a medium for the stimulation tool. All fields that were presented in the previous chapter would be suitable candidates for application of the Hydropuls® tool. My recommendation would be to use the acoustic device in all mentioned fields, evaluate the influence on the oil production and repeat the application where it showed a positive influence.

Another interesting recommendation would be the possibility to monitor the functionality of the acoustic tool from the surface by modern sonar technology.

Such a device could also be used on producers to detect the incoming wave. The penetration depth of the Hydropuls® tool could then be quantified more accurately.

It has also been reported in the literature it is possible to generate secondary waves as high as ultrasound by the low frequency waves emitted from the acoustic device. Those high power ultrasonic waves might be helpful when dealing with a bacterial problem (39), but further research needs to be done to see whether the Hydropuls® tool could bring this positive side-effect.

Another interesting point that may be considered is the resonance frequency of the reservoir rock, since the stimulation tool could be used most efficiently when set to that particular frequency. There is the possibility to estimate the resonant frequency from passive seismic (40), but again a more detailed investigation needs to be done to generate reliable estimations.

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List of Abbreviations

bbl	Barrel
CO2	Carbon dioxide
d	Day
EOR	enhanced oil recovery
ESP	electrical submersible pump
GLR	gas liquid ratio
GOR	gas oil ratio
HCL	Hydrochloric Acid
HF	Hydrofluoric Acid
Hz	Hertz
IOR	improved oil recovery
lb/ft	Pounds per Feet
m	Meter
m3	Cubic Meter
MD	Measured Depth
N	Nitrogen
OOIP	original oil in place
PCP	progressive cavity pump
RAG	Rohlöl-Aufsuchungs AG
STOIIP	stock tank oil initially in place
TVD	True Vertical Depth
TVDSS	True Vertical Depth Subsea
USA	United States of America

Appendix

The appendix contains the production history of the oil fields under closer inspection as well as the current completions of the candidate injectors.

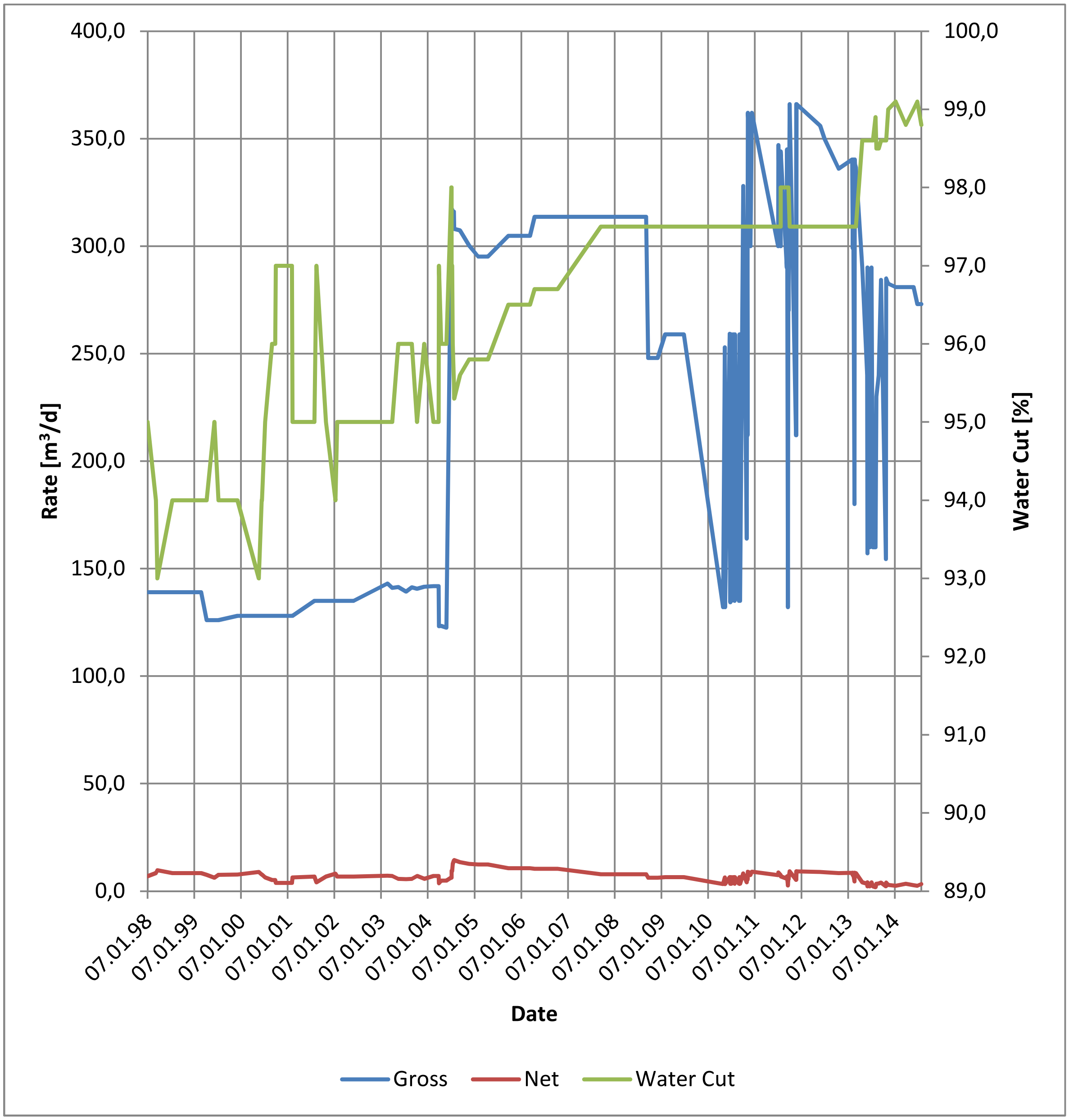


Figure 17: Production history of well *T-030* located in the field *Tau*

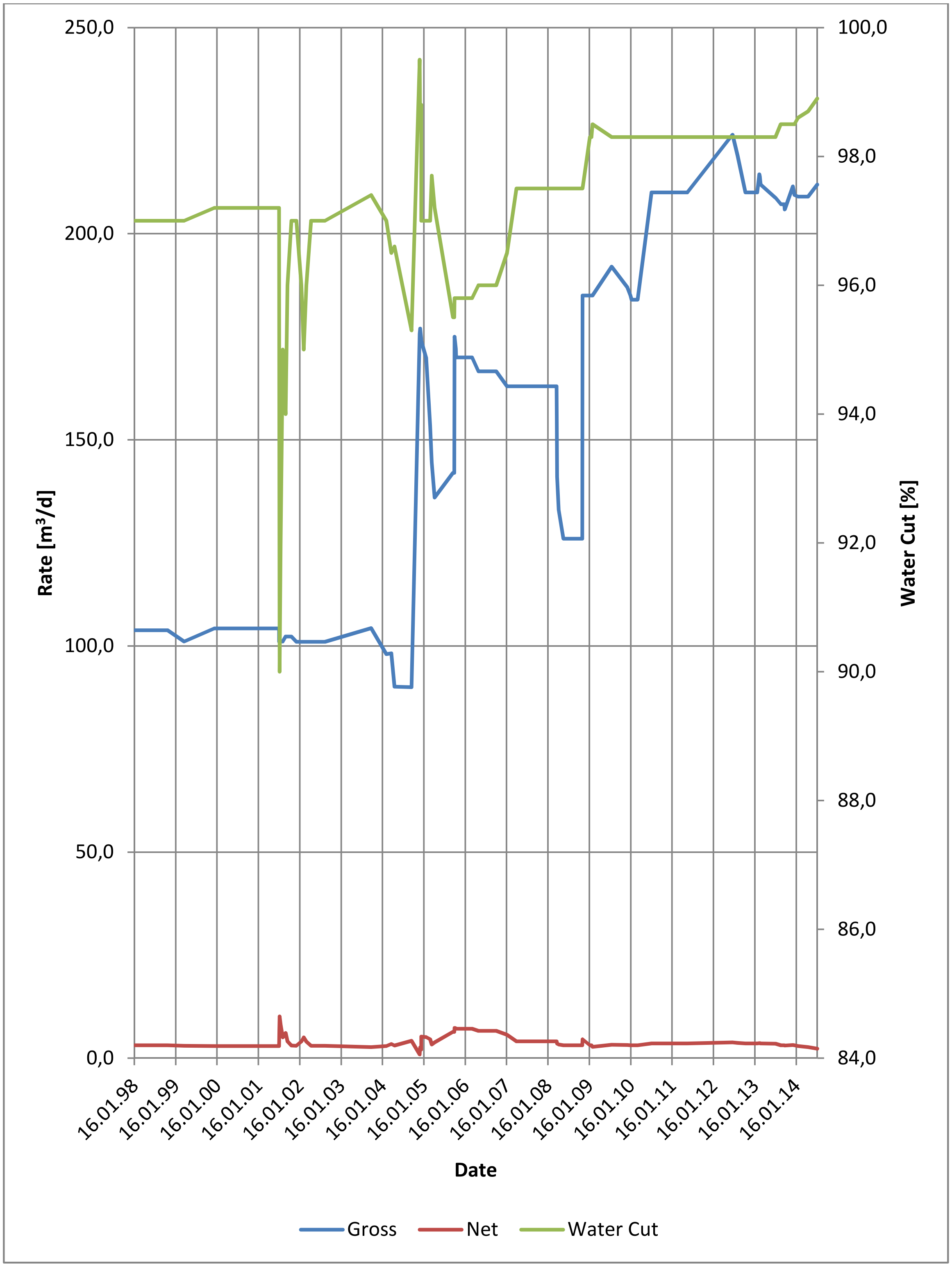


Figure 18: Production history of well *T-033* located in the field *Tau*

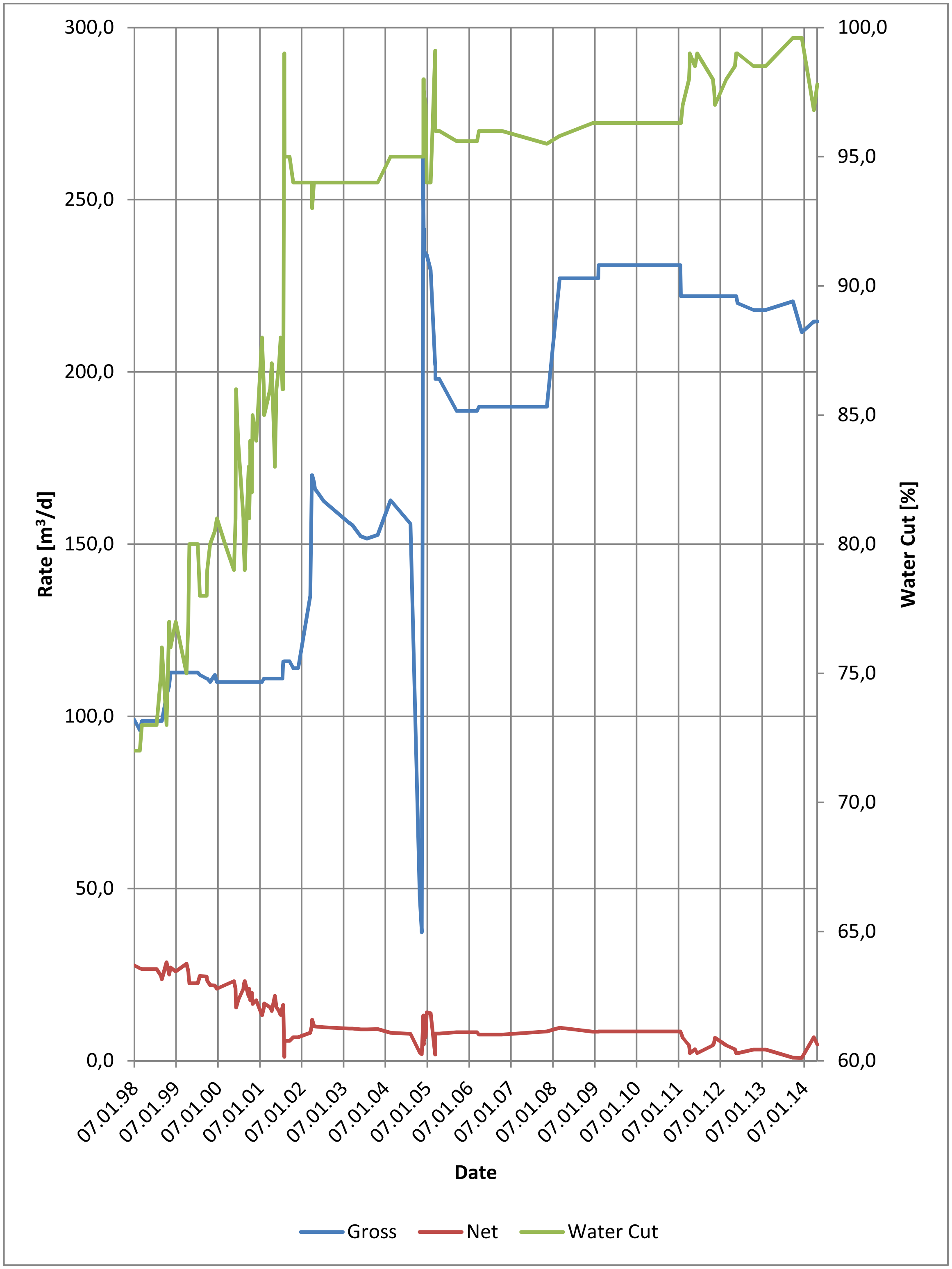


Figure 19: Production history of well *T-015-C* located in the field *Tau*

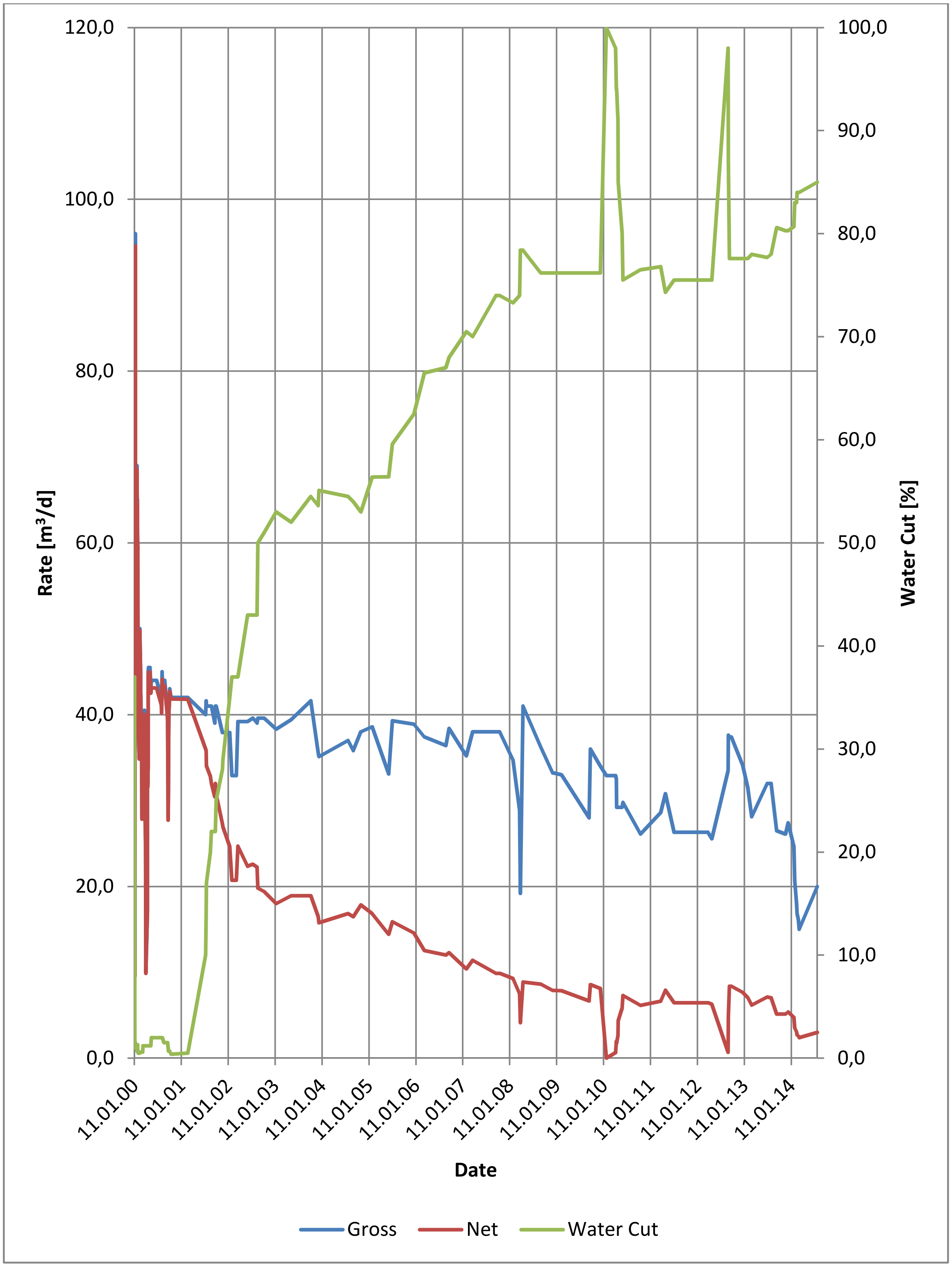


Figure 20: Production history of well T-013-A located in the field *Tau*

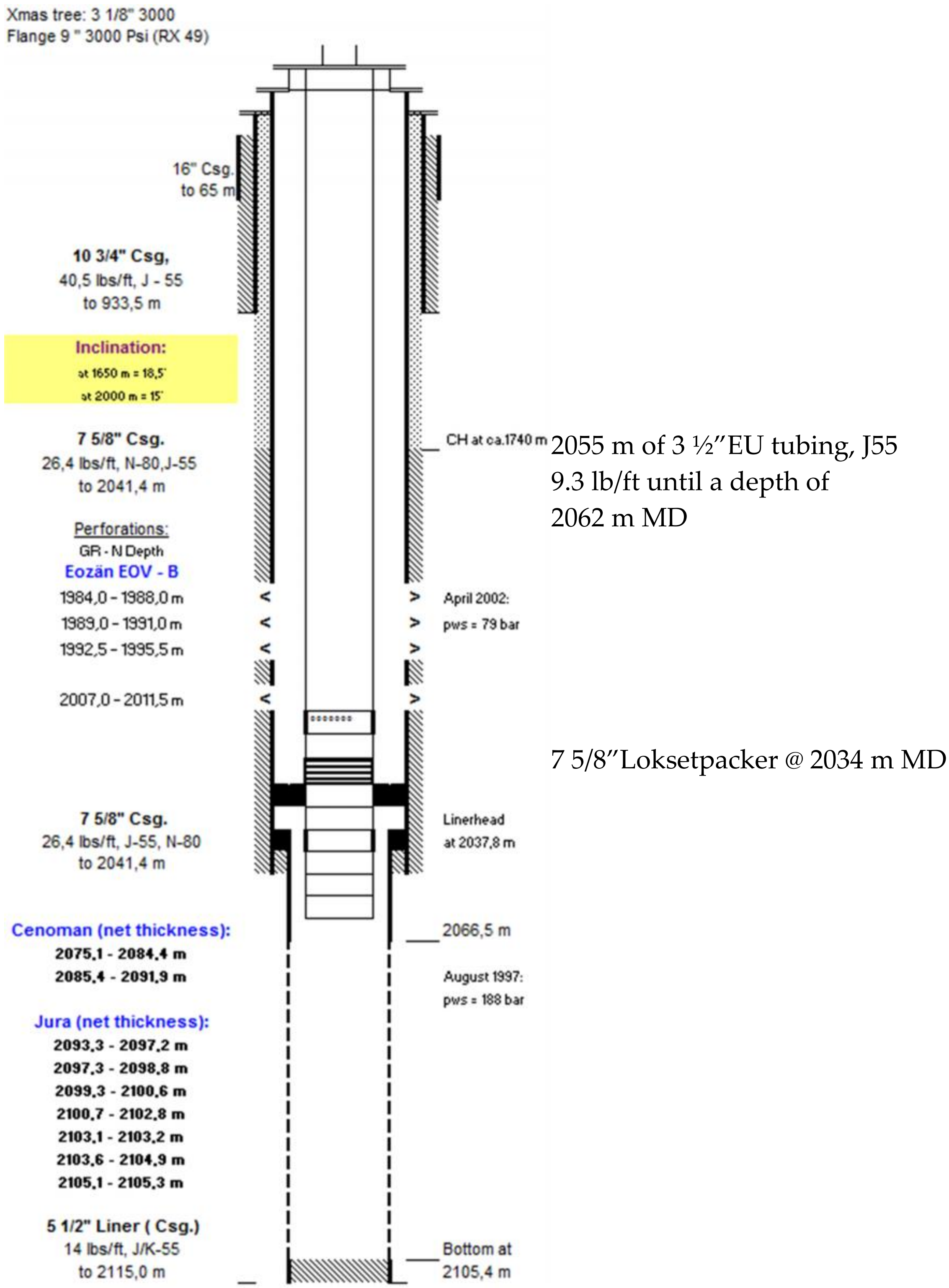


Figure 21: Current completion of *T-008* located in the field *Tau*

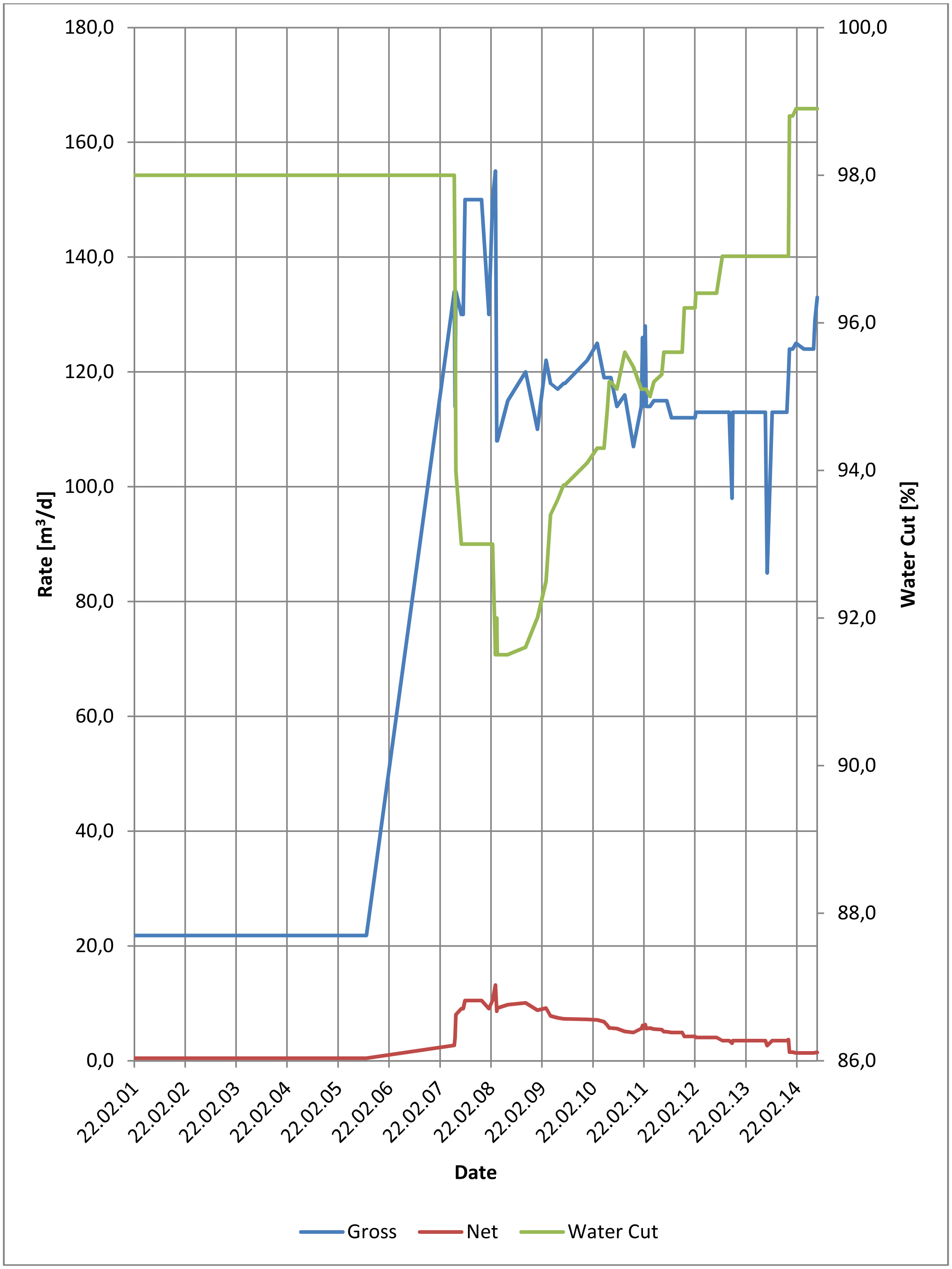


Figure 22: Production history of well *BE-W-1* in the field *Beta*

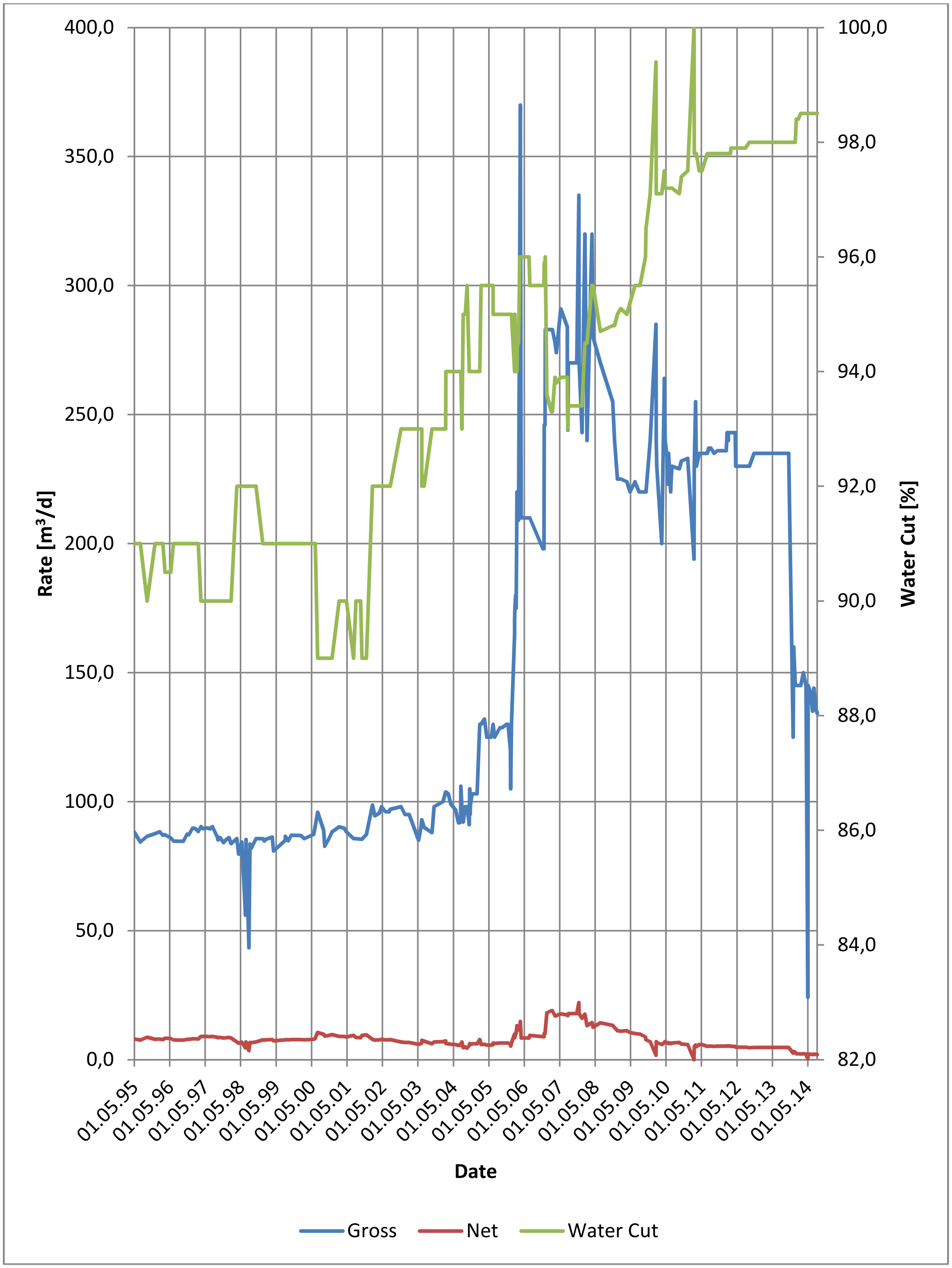


Figure 23: Production history of well *BE-W-002* in the field *Beta*

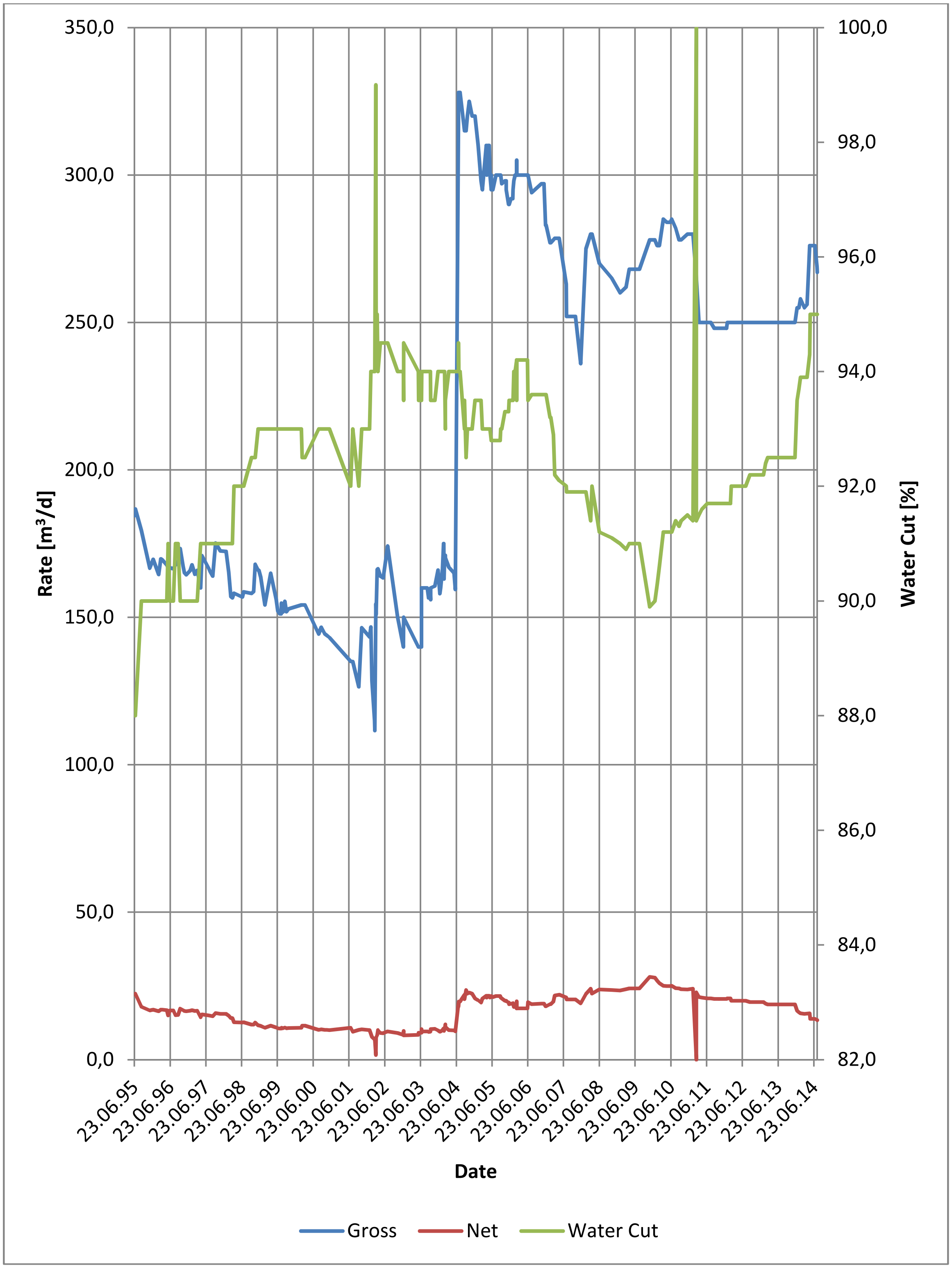


Figure 24: Production history of well *BE-001* in the field *Beta*

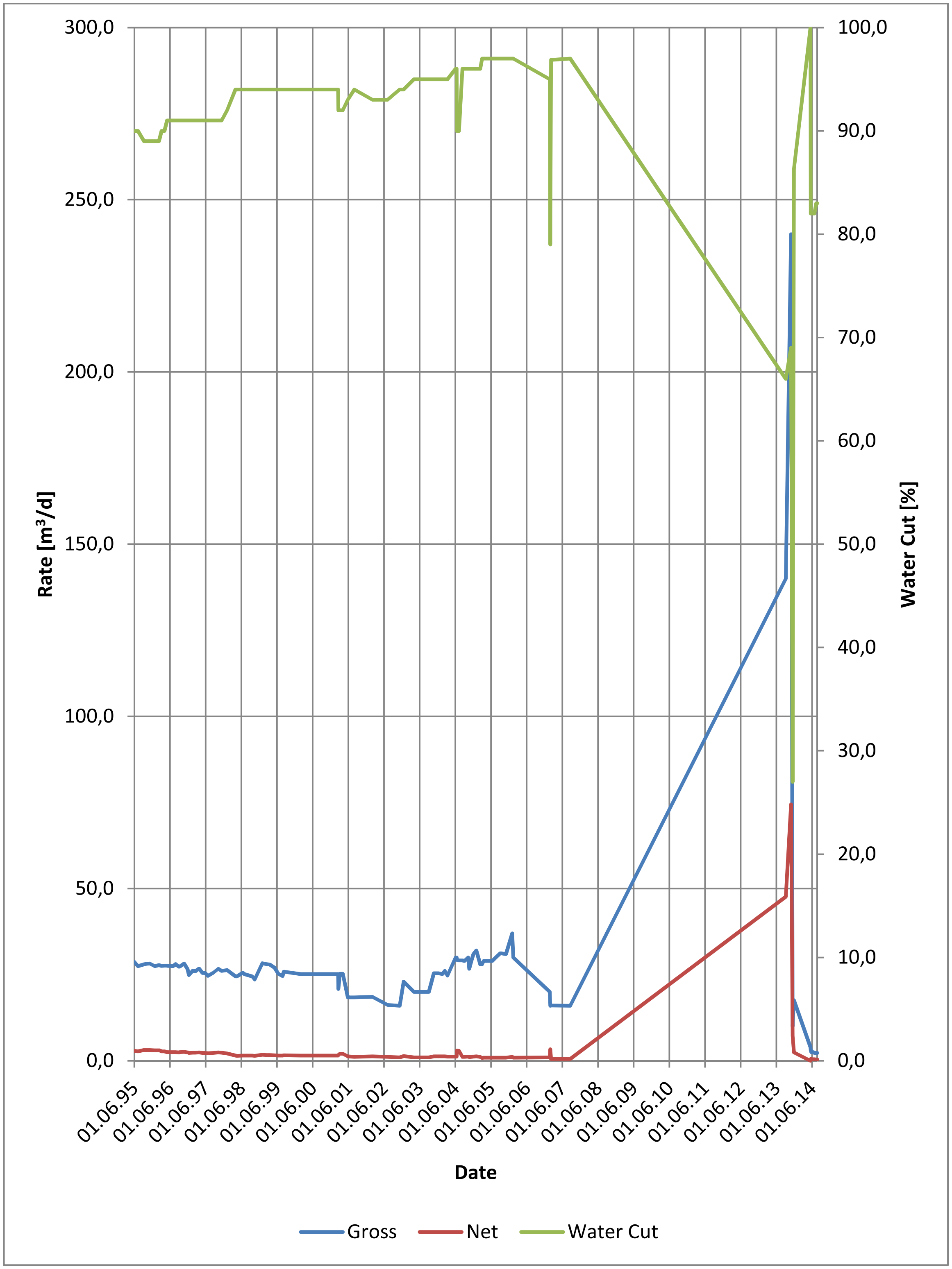
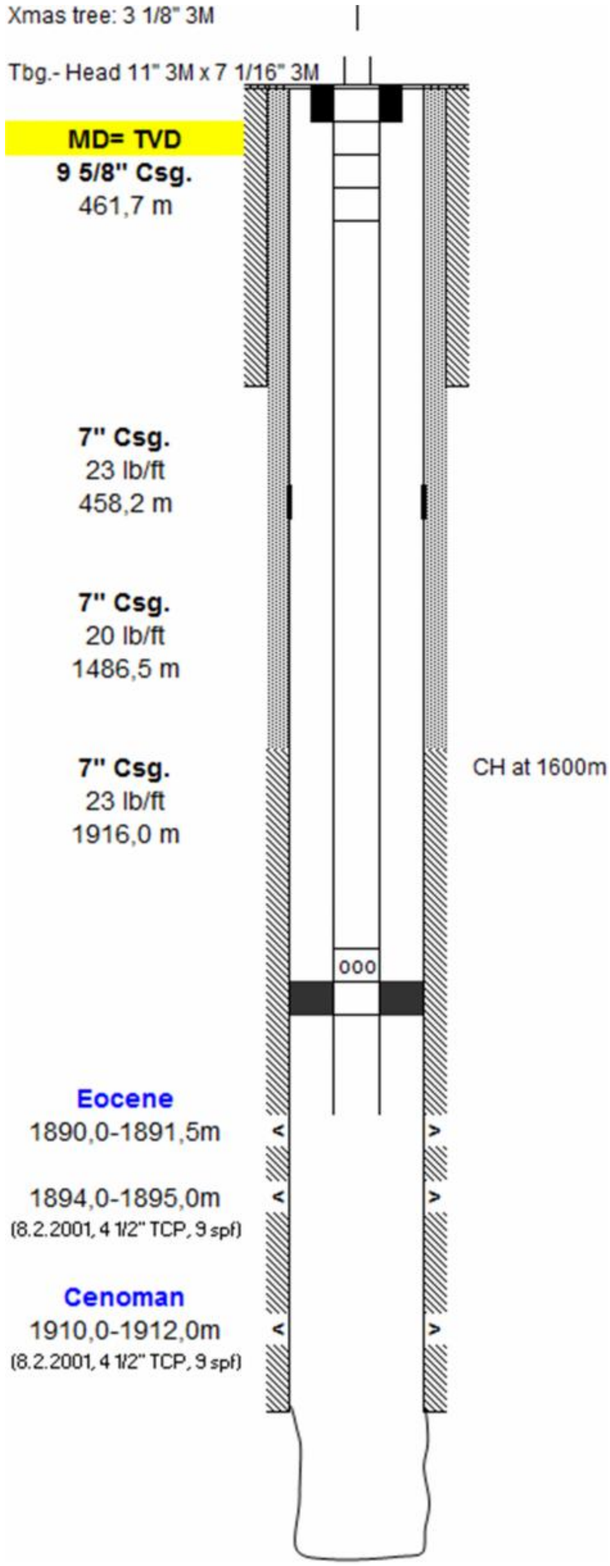


Figure 25: Production history of well *BE-004* in the field *Beta*



1885 m of 2 7/8″ Coated EU Tubing
6.5 lb/ft until a depth of 1890 m MD

7″ Loksetpacker @ 1872 m MD

Figure 26: Current completion of *BE-003* located in the field *Beta*

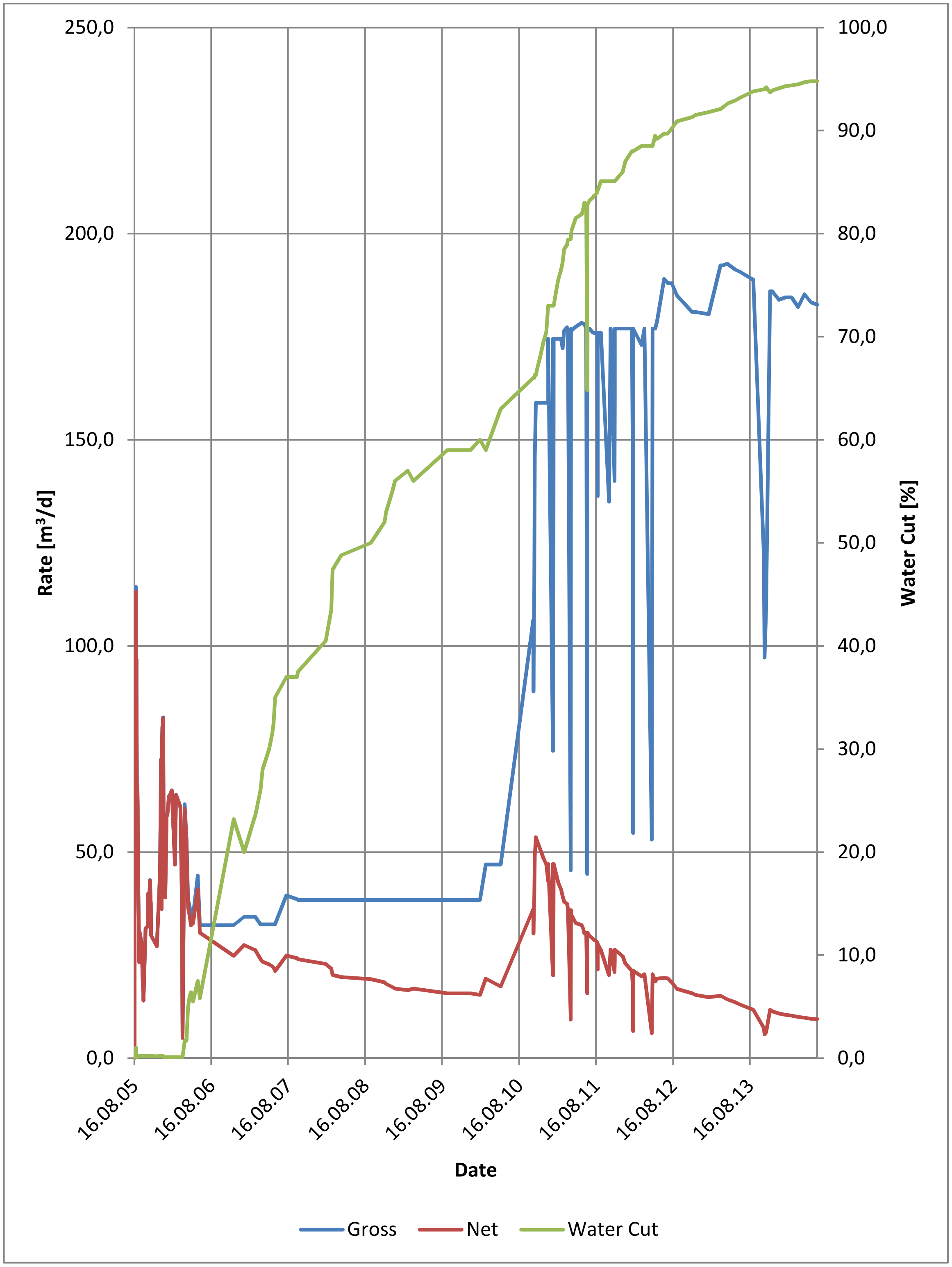


Figure 27: Production history of well *RH-005A* located in the field *Rho*

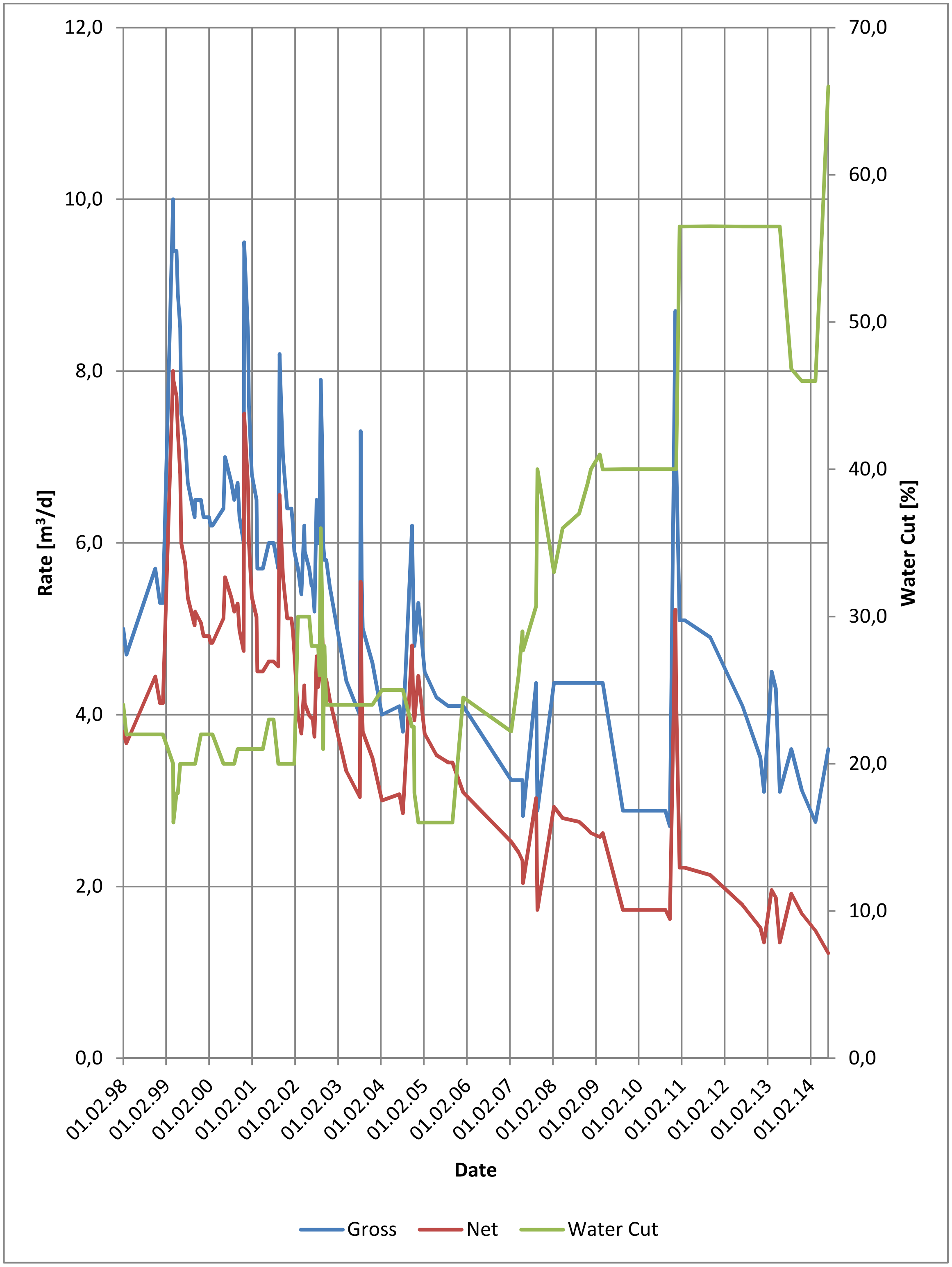


Figure 28: Production history of well *RH-006A* located in the field *Rho*

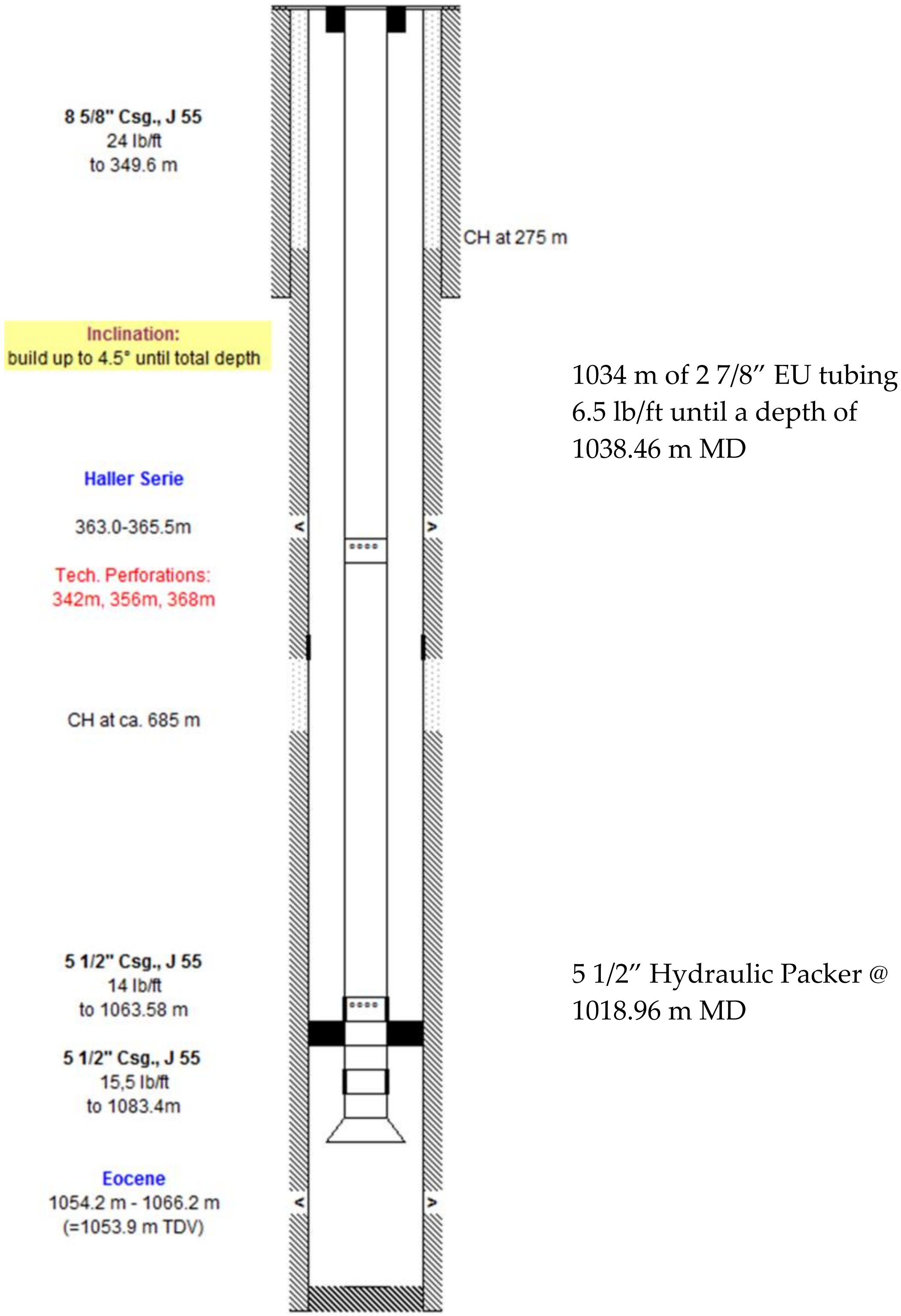


Figure 29: Current completion of *RH-001* located in the field *Rho*

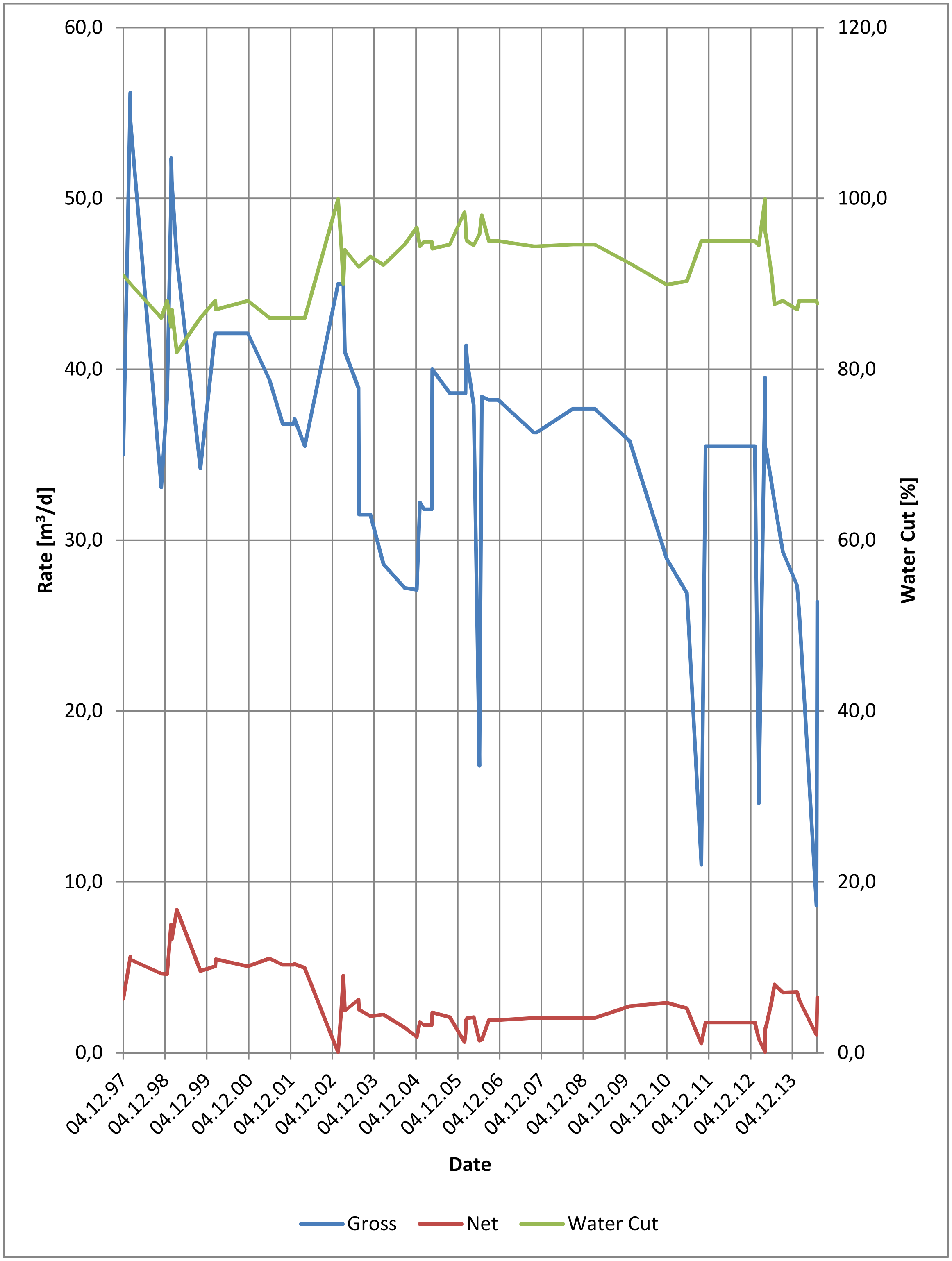


Figure 30: Production history of well *PSI-006* located in the field *Psi*

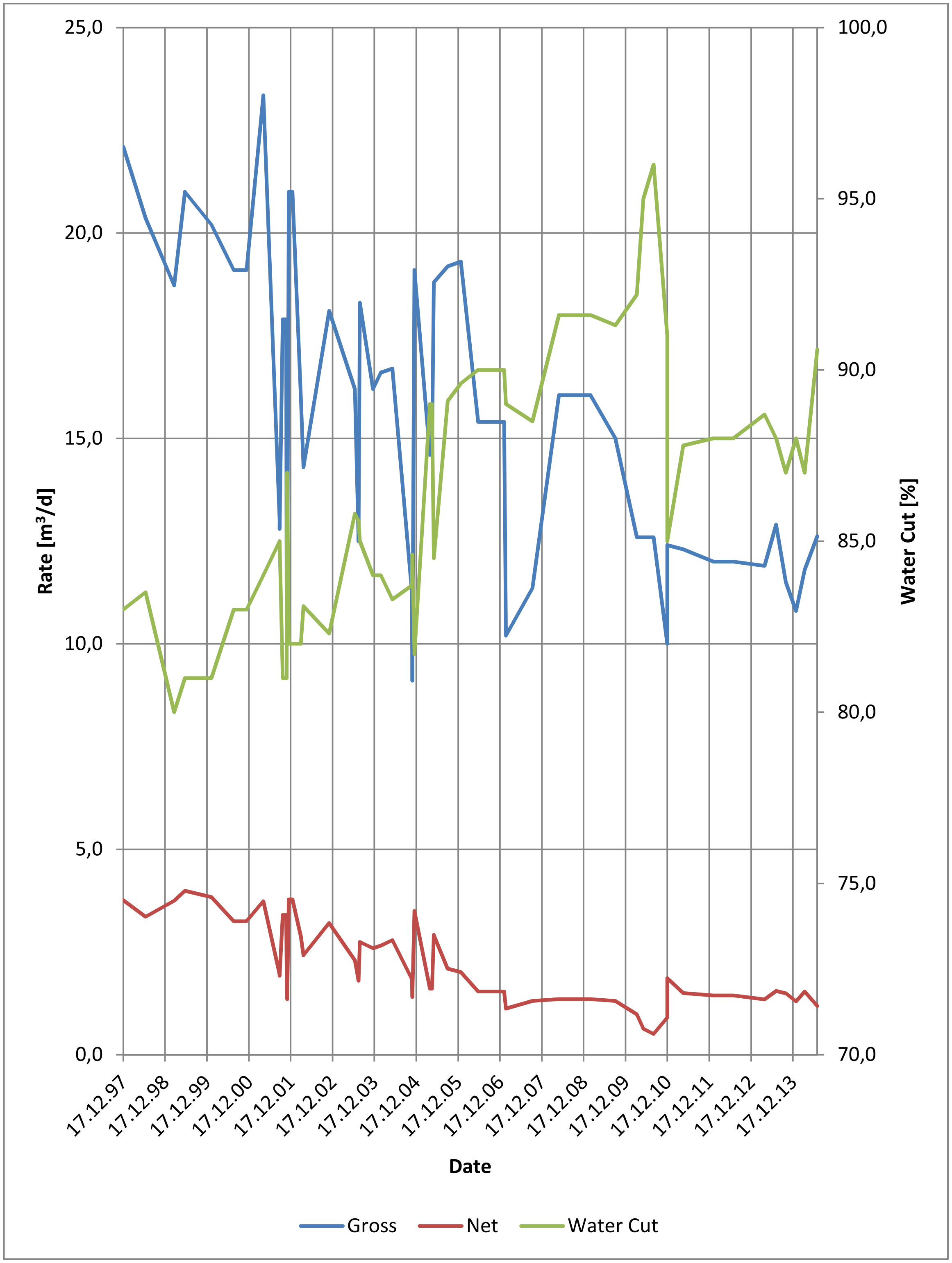


Figure 31: Production history of well *PSI-008* located in the field *Psi*

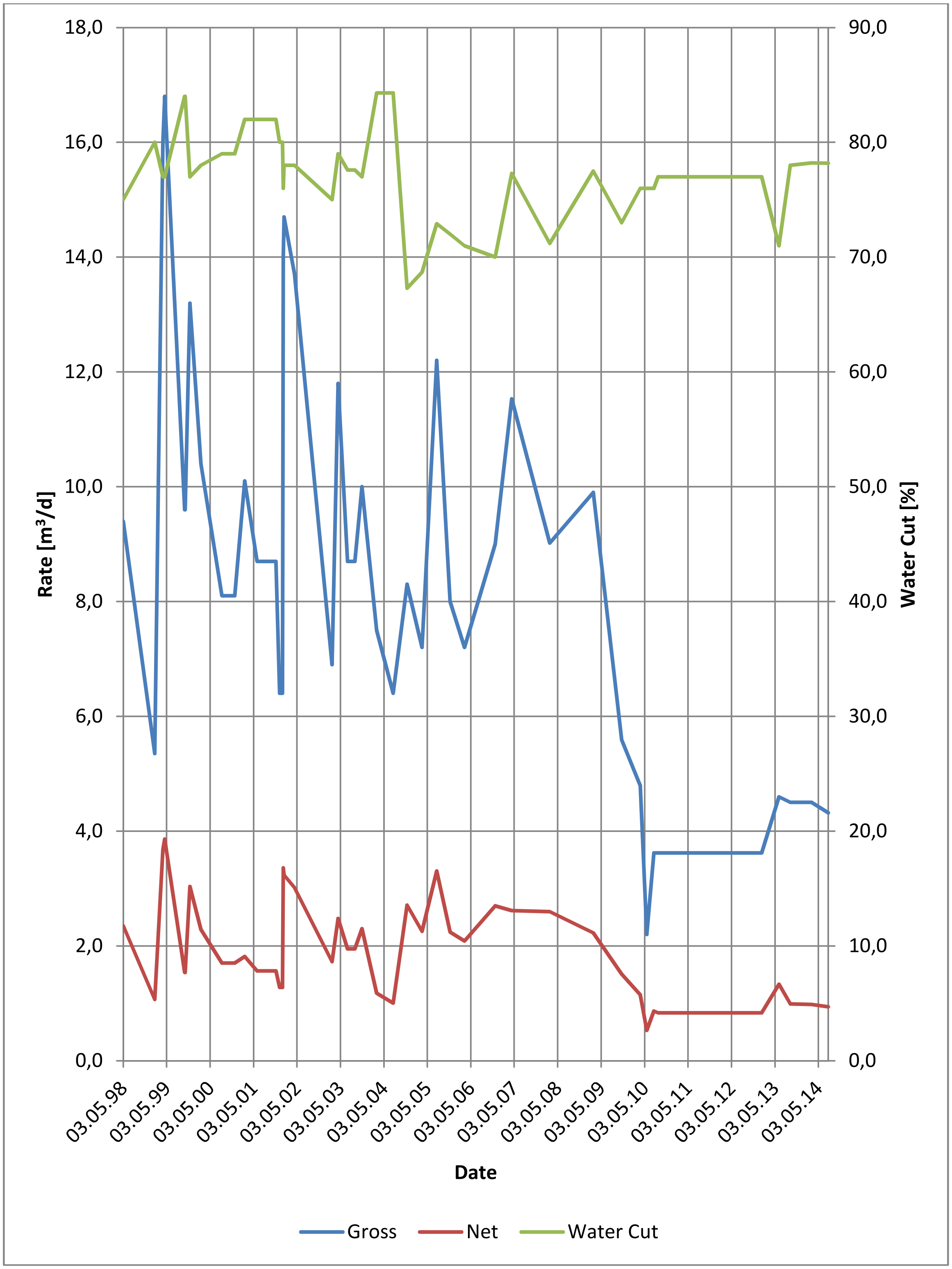


Figure 32: Production history of well *PSI-010* located in the field *Psi*

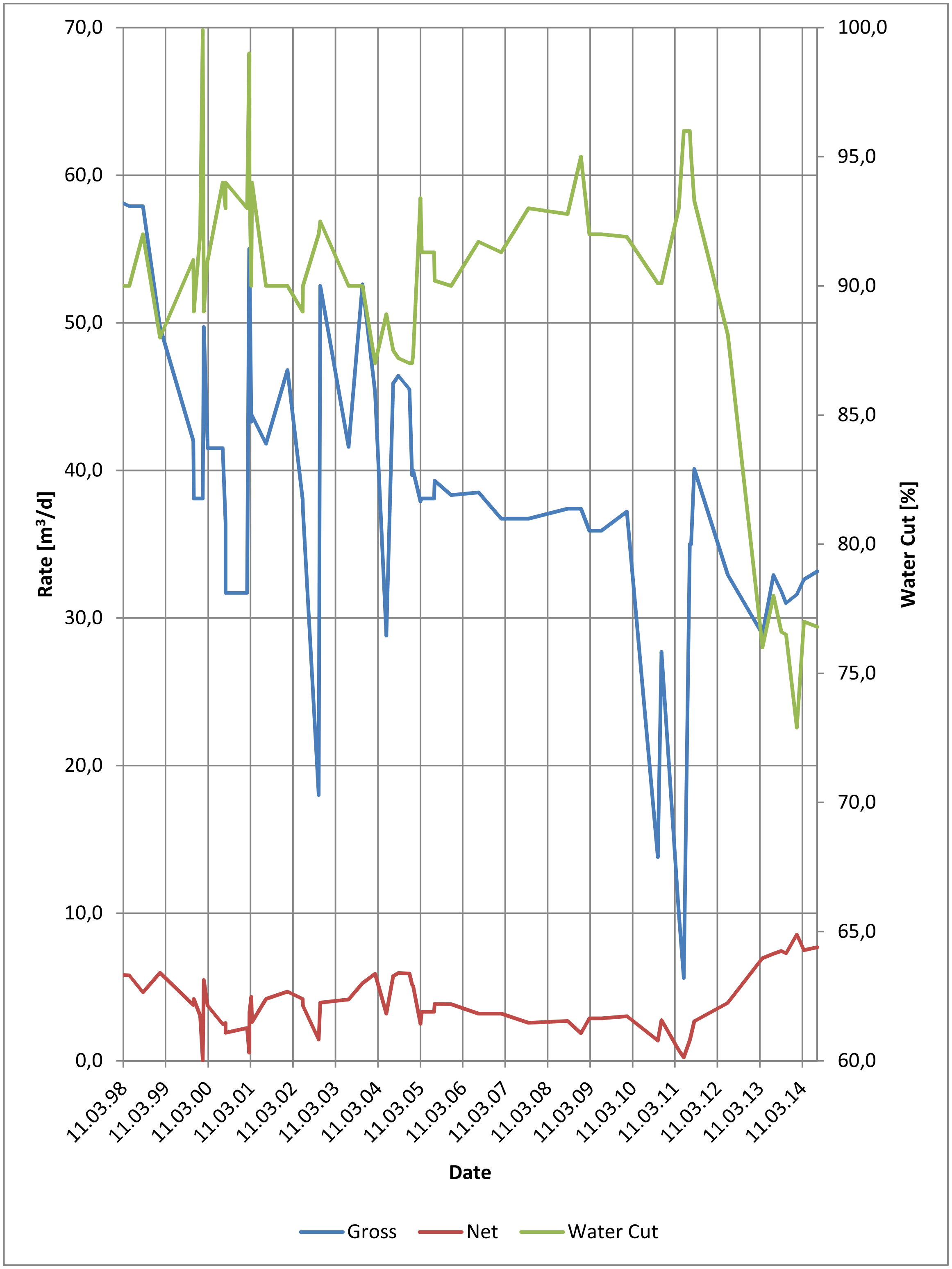


Figure 33: Production history of well *PSI-023* located in the field *Psi*

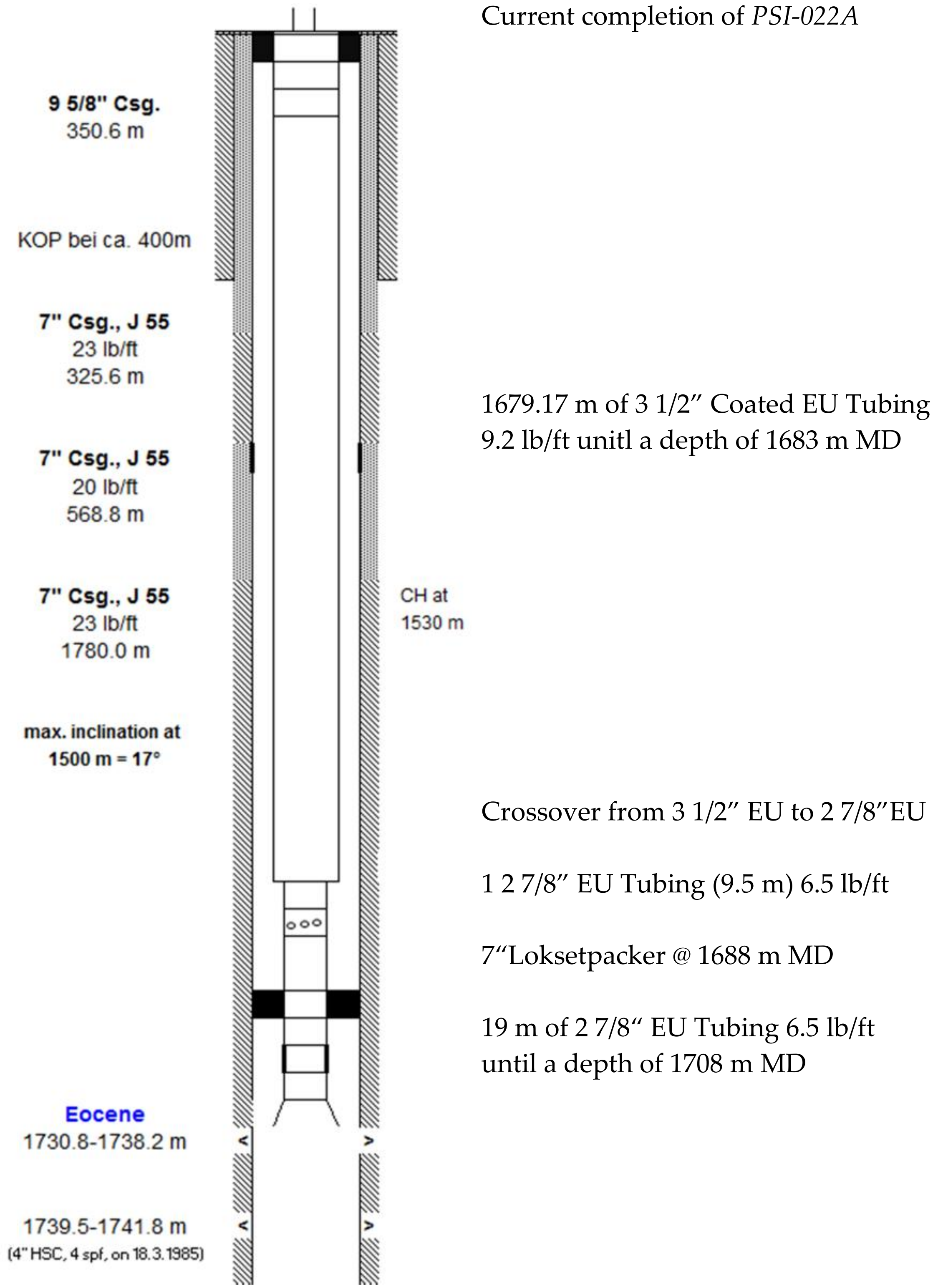


Figure 34: Current completion of *PSI-022A* located in the field *Psi*

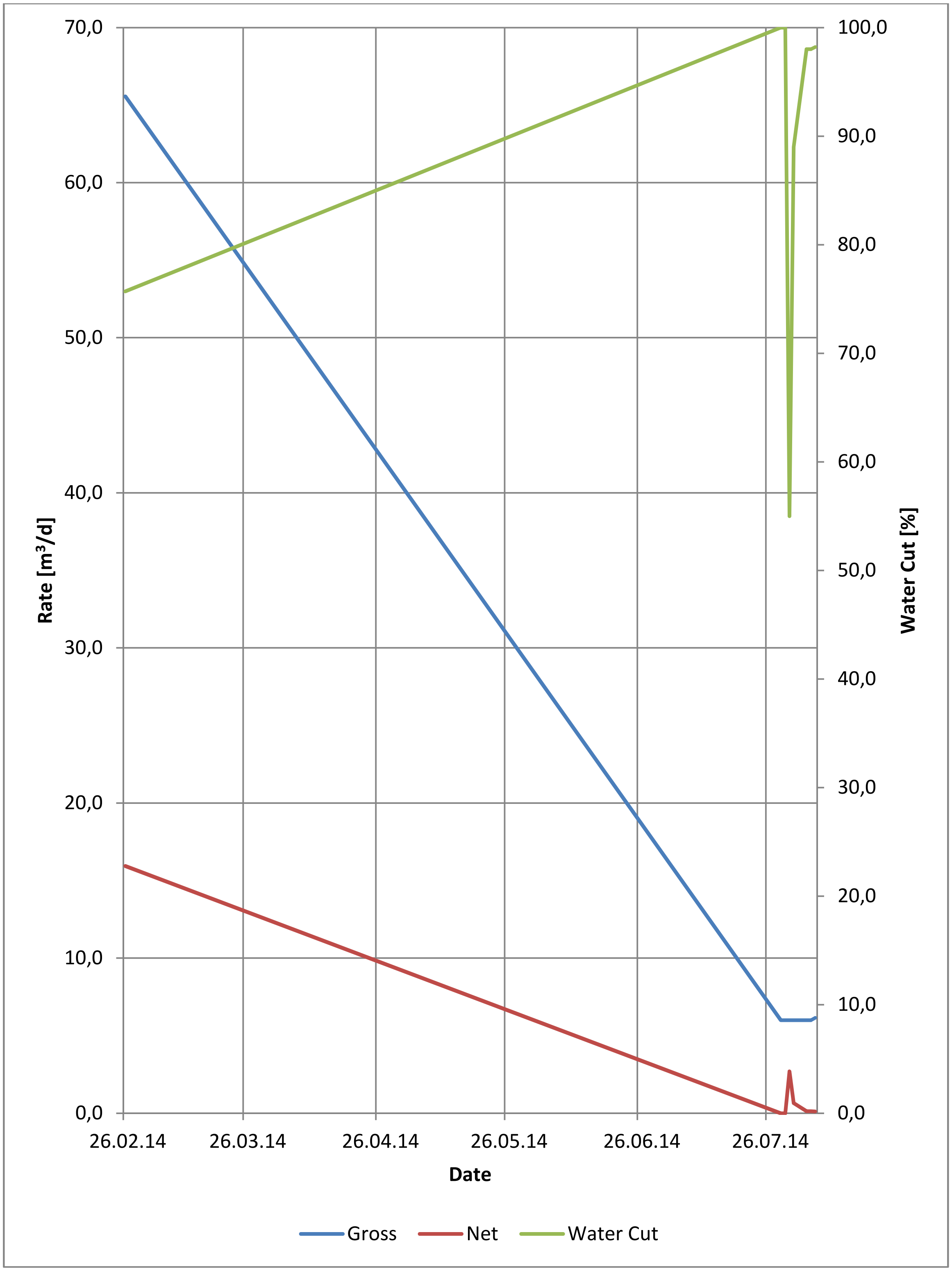


Figure 35: Production history of well *IOTA-006* located in the field *Iota*

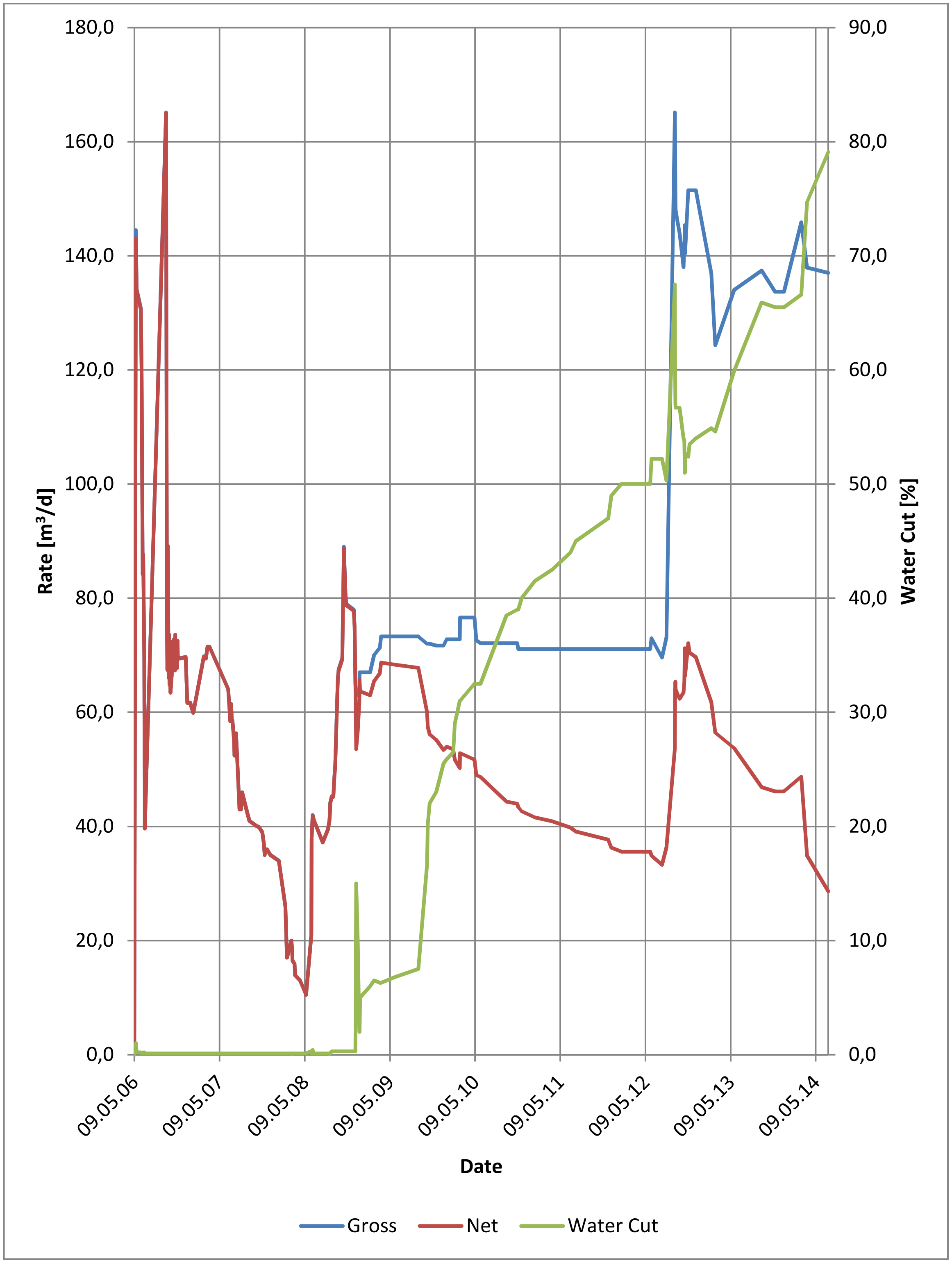


Figure 36: Production history of well *IOTA-001* located in the field *Iota*

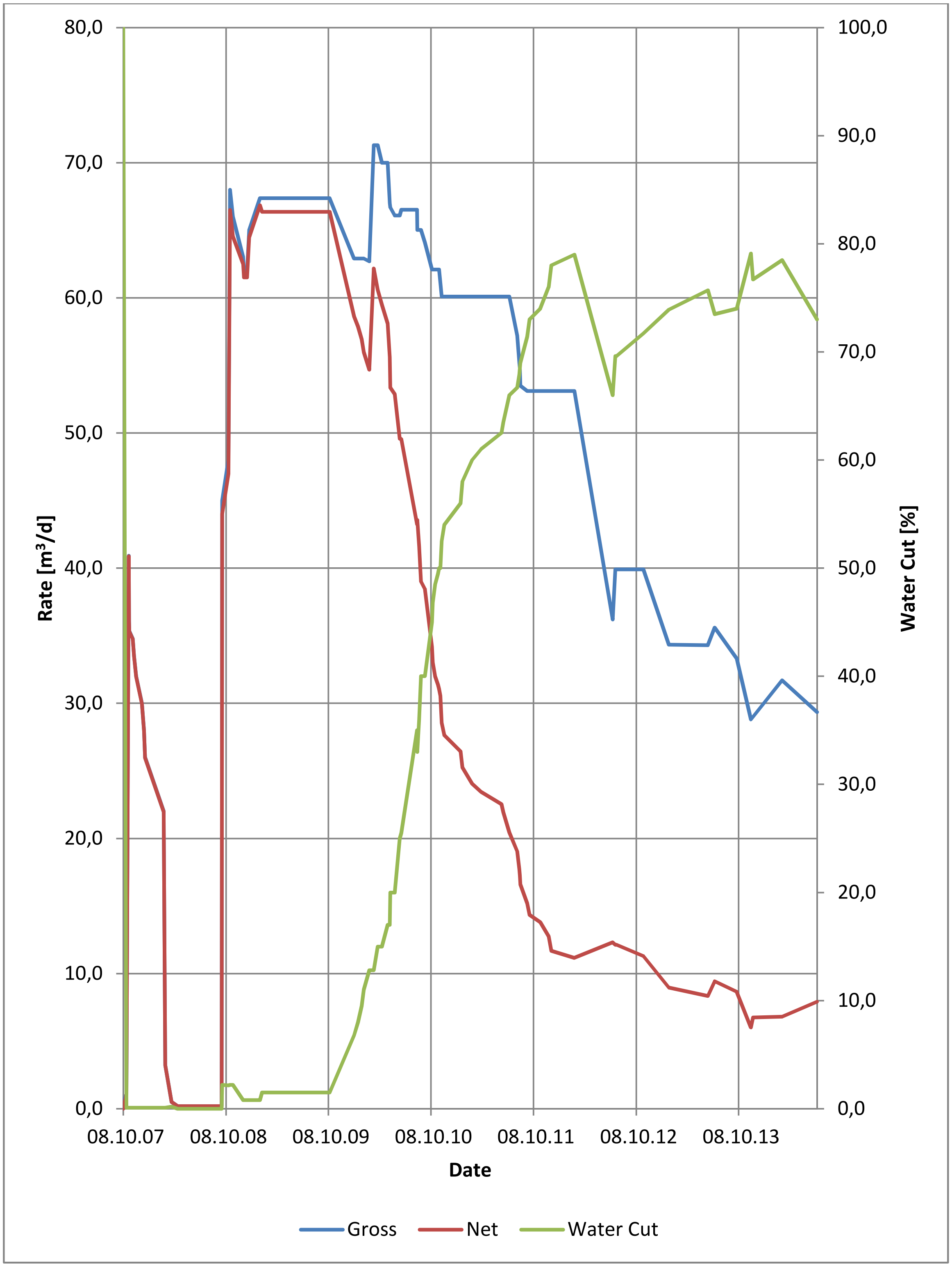


Figure 37: Production history of well *IOTA-004* located in the field *Iota*

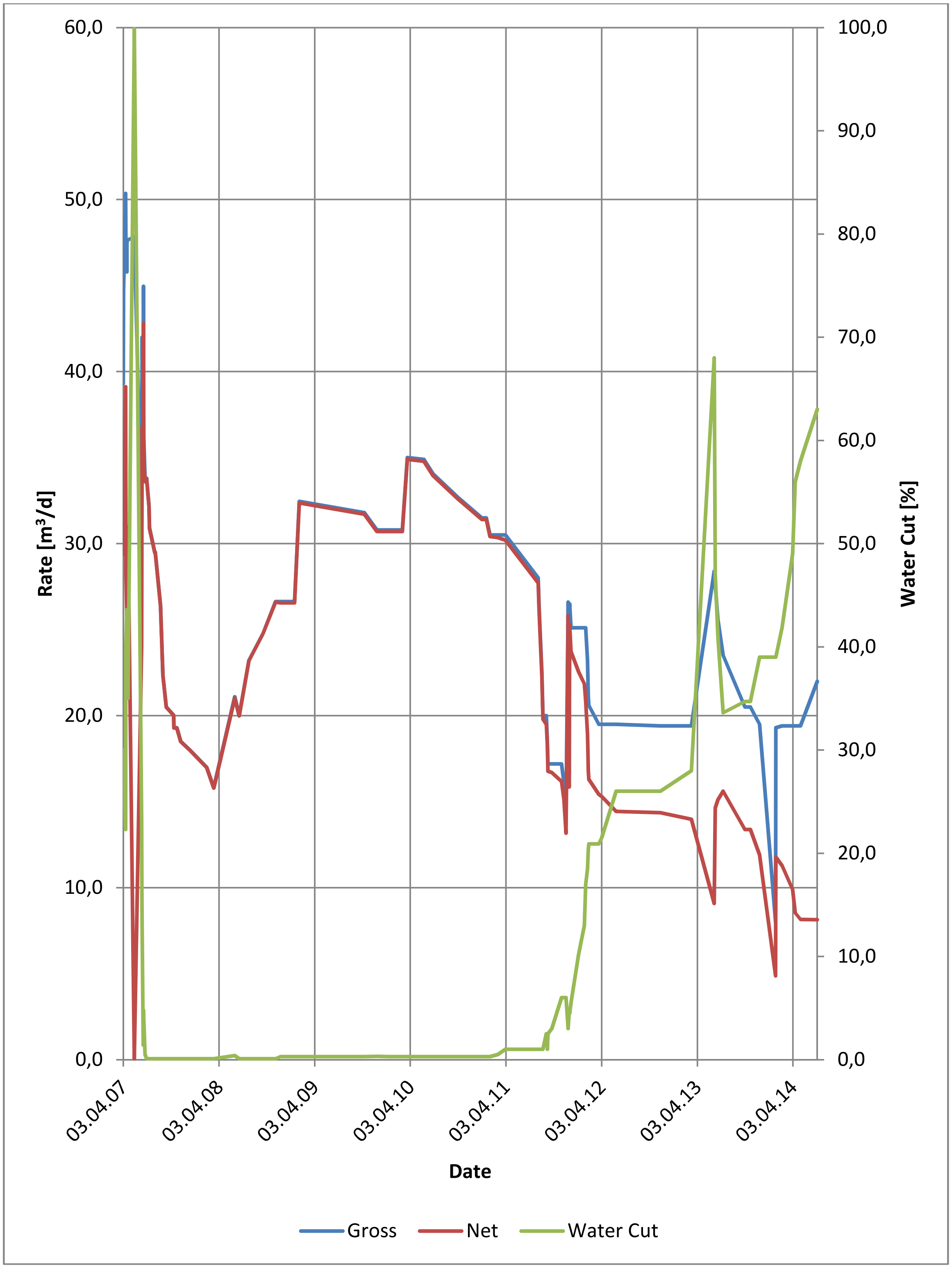
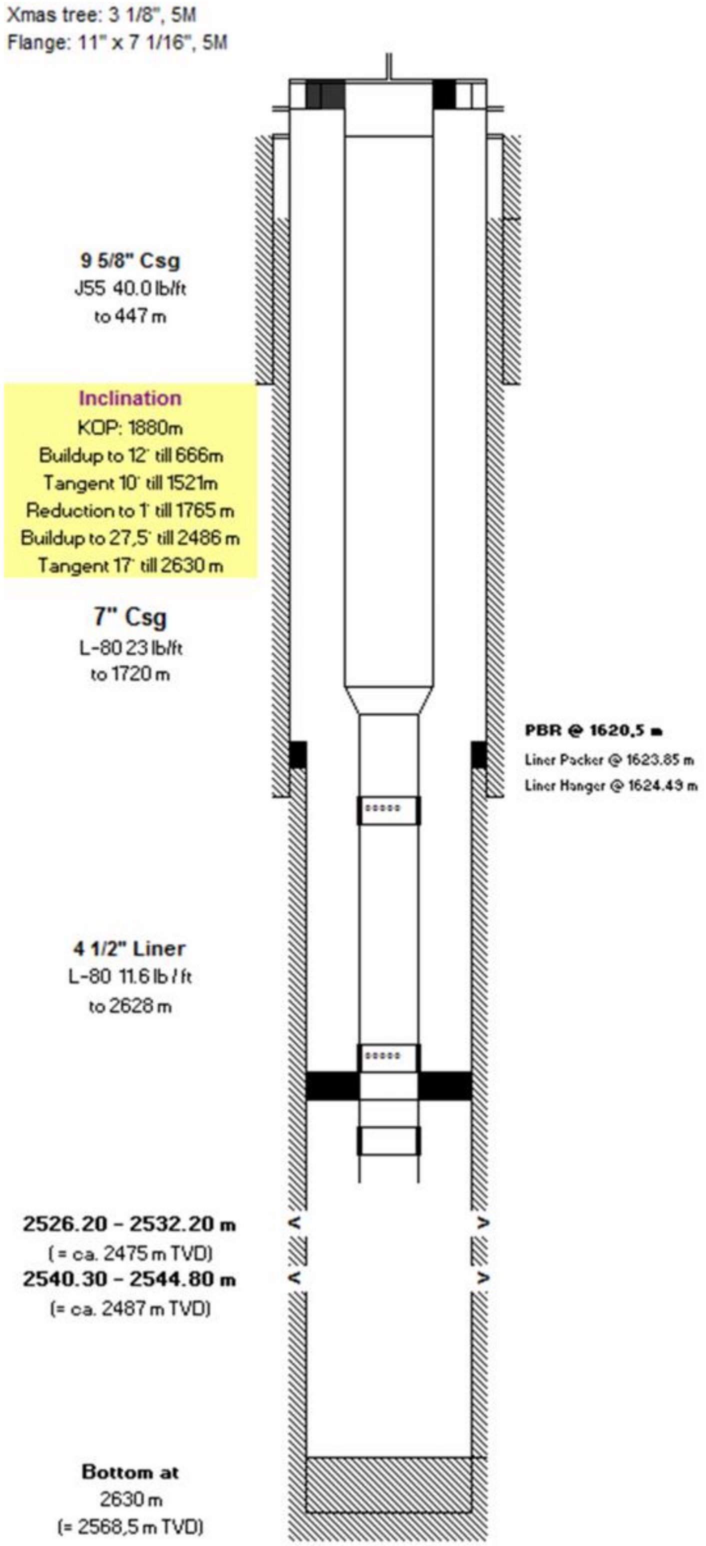


Figure 38: Production history of well *IOTA-002a* located in the field *Iota*



2608 m of 2 7/8″EU tubing, J55 6.5 lb/ft until a depth of 1608 m MD

Crossover from 2 7/8″ EU to 2 3/8″ EU

904 m of 2 3/8″ EU tubing, J55 4.7 lb/ft until a depth of 2515.95m MD

4 1/2″ Lokset Packer @ 2497 m MD

Figure 39: Current completion of *IOTA-003B* located in the field *Iota*

Datum	Probenahme stelle	KW mit Al2O3 [ppm]	WBF [8µm]	entölt >8µm [mg/l]	entölt u. gesäuert) >8µm [mg/l]	HCl-säuerbare >8µm [mg/l]	unfiltriert	< 3µm	< 8µm	< 0,45µm	abfiltrierbar	[pg/mL] bei 20mL Probe
28.08.2013	EN-1 WT	114	0,09	0,2	0,2	0	0,94		0,53	0,5	0,44	156
02.09.2013	EN-001 WT	79	0,09	0,5	0,4	0,1	0,4		0,35	0,26	0,14	56
04.09.2013	Sat-W-22	215	0,34	0,9	0,8	0,1	1,4		1,04	0,63	0,77	216
05.09.2013	Sat-W-22	155	0,33	1	0,9	0,1	1,18		0,83	0,75	0,43	282
09.01.2014	WT-Ausgang	31	1,05	4,4	2,7	1,7	1,09		0,46	0,27	0,82	2690

Figure 40: Solid particle analysis for injection water