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Forfatter: André Larsen	………………………………………… (signatur forfatter)
Faglig ansvarlig: Bernt S. Aadnøy Veileder(e): Steinar Edholm and Jarle Pedersen	
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Gas in overburden on Ekofisk

By

André Larsen

Master thesis in Petroleum Engineering

Department of Petroleum technology
Institute of Technology and Science
University of Stavanger
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I. ABSTRACT

The Ekofisk field is a large producing oil and gas field located in the southern part of the Norwegian sector of the North Sea. The production started in 1971. During the production, the reservoir has been decompressed due to depletion and in 1984 it was discovered that the Ekofisk field was subsiding.
In this project, quantitative data were collected and processed to determine if there is a trend of increasing volume of gas in overburden over a periodic time.

This paper visualizes the development of the gas in overburden over time. After comprehensive work it seems like there is an increasing trend of more aggressive, mobile gas in the overburden at present time compared with few years ago. This development is most visible at the shallowest depths, especially at 3300 ft where the gas starts to enter the wells. This development can be explained by the fact that the reservoir has been decompressed during 30 years of production, a load the overburden could not withstand. Subsidence of the overburden have changed both the vertical and horizontal effective stresses and a corresponding development and change in cracks and channels can be the main factor of the observed increasing trend of gas over time.

Gas injection on the Ekofisk field started in February 1975. The weak correlation of GOR in some wells and the fact that five wells started to produce injected gas before the bubble point was reached, indicate that gas channeling is a factor at Ekofisk. The gas can have migrated upwards the formation along the casings over a geological time period.

Based the evaluation of the cuttings injection wells and the leak water injection well, 2/4-K-22, it can be concluded that there is not a clear relationship between the injectors and the behavior of the gas in the overburden. The SE area is the least gas bearing area even if this area contains both a cuttings injector and the leak water injection well. The SW area seems to be the most gas bearing area after the division of the field into four areas, NE, NW, SE and SW.

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Stavanger, June 2007

1. INTRODUCTION

The Ekofisk field is a large producing oil and gas field located in the southern part of the Norwegian sector of the North Sea. The production from the giant Ekofisk structure started in 1971.The Ekofisk structure consists of chalk and has an elliptical, anticlinal shape. The field has a maximum oil column of 1000 ft. The initial pressure and temperature of the reservoir at the Ekofisk field was 7135 psia and 267.8 ^{0}F at 10400 ft. The Ekofisk field has been depleted during production, but during water injection, the field has been depressurized due to the observed subsidence. During 30 years of production, the pressure has decreased to 5100 psia. In 1984 it was discovered that the Ekofisk field was subsiding. This subsidence is dominated by reduced pore pressure caused by the production from the field for over 30 years. Ekofisk is still a major producing field, with an average production of oil and gas in 2006 at 273000 bbl/day.[1-4].

The presence of gas in the overburden, above the crest of the field, is a well known feature. The gas cloud is less extensive above approximately 7000 ft TVDSS and markedly above 5000 ft TVDSS. It seems like the gas is trapped below the mid Miocene unconformity.[5]. Because of the gas cloud over the crest of the field it causes problems during the drilling section. There is also an assumption that the gas is behaving more “aggressively” in the last few years.

In this project, quantitative data were collected and processed to determine if there is a trend of increasing volume of gas in overburden over a periodic time. To determine this I have collected data of the gas in the mud for approximately 50 wells, drilled from 1999 – 2007.

The estimated drilling operations in average cost 1.6-1.7 millions NOK/day. This includes everything from logistics, offshore operations to support from onshore. Due to the costs and danger of the drilling operations in “gas-layers” it is important to map and determine the gas in overburden. The drilling operation can extend from a few days extra to several weeks because of gas related problems. Gas in overburden gives problems which are complex, because two criteria's must be fulfilled:

1. The weight of the mud must be high enough for the well-control.
2. The weight of the mud must be low enough, to prevent exceeding leak off of the overburden shales.

When high volumes of gas are encountered, common procedure is to decrease the ROP (rate of penetration) to circulate out the gas. This can delay drilling time with several days. If the weight of the mud gets to high, there is a risk of fracturing the shales in the overburden, in addition to the risk of loosing circulation when approaching top of the reservoir in the lower part of 12 ¼" section.[3].
Gas in the overburden is complex and results in challenges in the drilling operation and casing design.

In this thesis, I will describe the history of the Ekofisk field and all the parameters which can be of interest in this study. The next section of this thesis includes empirical data and the analysis of these data. Finally, I will give a conclusion if there actually is more gas in the overburden at present time or if this is just an illusion? And if there is more gas at present time, I will give a conclusion why there is an increased volume of gas in the overburden with respect to the drilling operations.

”Gas in overburden on Ekofisk”

2. THEORY

2.1. The Ekofisk field

2.1.1. History of the Ekofisk field

The Ekofisk field is a large producing oil and gas field located in the southern part of the Norwegian sector of the North Sea [5].

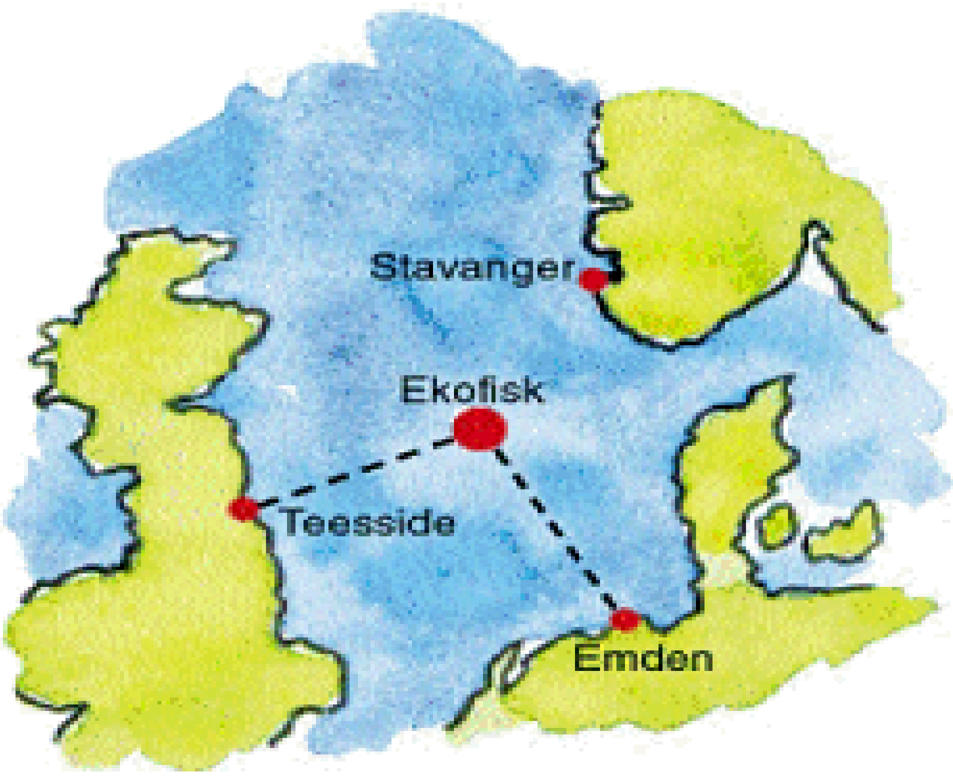


Figure 01. Map of the Ekofisk field [6].

In 1963, the Phillips Norway Group started seismic surveys in the Norwegian sector of the North Sea. Exploration drilling was started in 1967 and led to the discovery of the Cod gas-condensate sandstone reservoir in 1968 and the Ekofisk chalk field in late 1969.[7].

The chalk reservoir was penetrated on October.25.1969. Primary target was the Jurassic, as the Ekofisk structure was not visible on the seismic interpretations due to the gas cloud, creating a seismic "pull down". The 2/4-C-08 well in 1974 showed that the Ekofisk structure was really an anticlinal structure. The Ekofisk structure has probably been created as a result of halokinesis (salt movement) and compressional tectonics. To date, however, the salt has not been penetrated on Ekofisk. The anticline is elongated and covers 12000 acres. The major axis, in the north-south direction, is about 10 km long, and east-west extends roughly 5 km. The Ekofisk structure can be divided into two formations; The Ekofisk formation and the Tor formation, separated by the Ekofisk tight zone (EE-layer).[1, 2].

The depth of the Ekofisk formation is about 9600 ft at the top of the structure. The chalk in the Ekofisk formation is of Danian Age of Lower Paleocene time. The Tor formation, which underlies the Ekofisk formation, is of Maastrictian Age of Upper Cretaceous time [1]. A 30-60-ft low porosity layer, known as the Ekofisk Tight Zone, separates the Danian age Ekofisk formation and Maastrictian age Tor formation.[5].

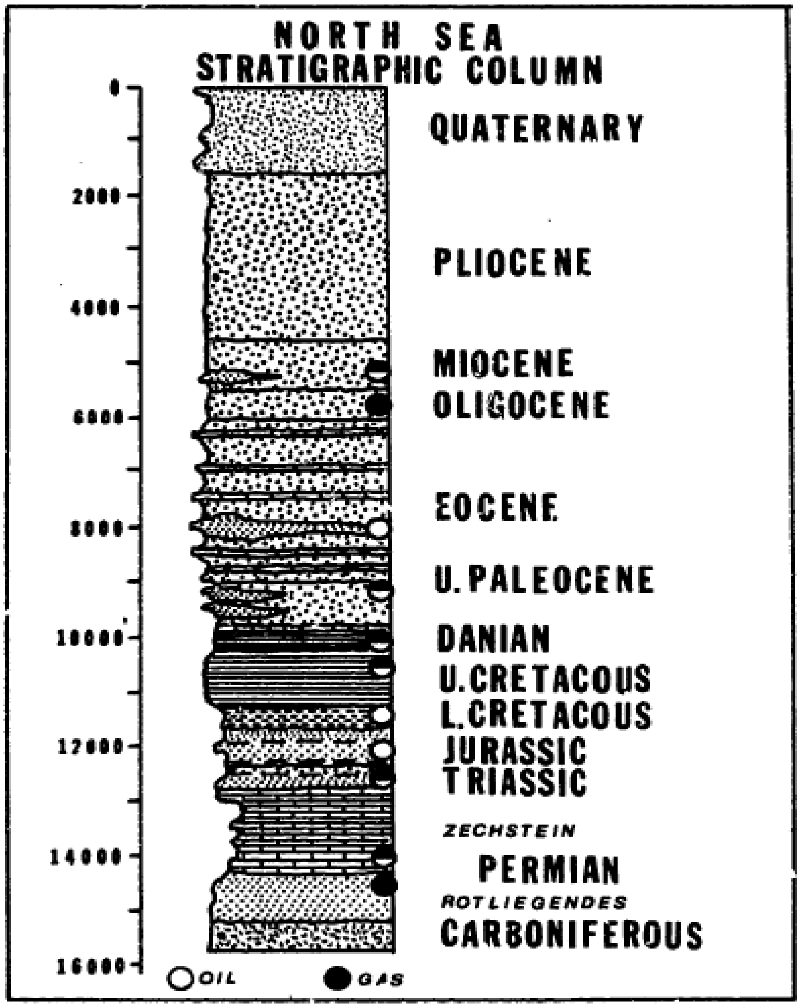


Figure 02. Geologic time period over the North Sea formation [8].

The Ekofisk reservoir thickness is 350 to 500 ft in the Ekofisk formation and 350 to 500 ft in the Tor formation [2].

The overburden overlying the Ekofisk field shows relatively little lithological differentiation. Different seismic surveys, logs from about 300 wells and cutting samples, indicate that the overburden consists almost entirely of claystone and shales. The Ekofisk reservoir is overlaid by the Rogaland group, predominantly made up of shale. The Hordaland group, lying above the Rogaland group and ranging in depth from approximately 5000 to 9000 ft TVDSS, is made up of shales with some limestone stringers. In the uppermost 1800 ft of the overburden, thick Quaternary sand intervals with clay stone are present.[5].

The initial hydrocarbon volume at the Ekofisk field was 7 billion oil equivalents. The production from the giant Ekofisk structure started in June.1971. In 2006, the average production of gas and oil was 273000 bbl/day. After 30 years of production, the reservoir pressure has decreased to 5100 psia. This production caused a reduction of the pore pressure and causes change in the effective stress, since the initial pressure and temperature was 7135 psia and 267.8 ^{0}F. The main driving force in a HC-reservoir is the initial reservoir pressure. The differential pressure between the reservoir pressure and the surface/hydrostatic pressure is the driving mechanism for the production. During the production of oil and gas, the reservoir pressure has decreased and the differential pressure is reaching 0 psia. To compensate declining reservoir pressure, a major water injection program was implemented in 1986/1987. This injected water has increased the recovery factor for the reservoir from initial 20 % to 45 %. The injected water also has some negative consequences. The experts thought that the water injection would reduce or even stop subsidence, while in real life it seems like the water injection has accelerated the subsidence, due to the so called water weakening effect. Recent studies, which will be described in a later chapter, have showed a chemical reaction between water and chalk, and this reaction together with the natural drive mechanism, production, has been the main factor for the compaction of the reservoir and the corresponding subsidence of the overburden. The main purpose of the water injection is to maintain the reservoir pressure, and at one stage the water is believed to prevent further compaction of the reservoir. This subsidence causes problems during the drilling operations.

Subsidence of the overburden causes changes in the stress regime which gives more cracks and channels which again makes the gas more mobile. Increased volume of gas in the well/drilling mud gives increased danger of explosion at surface, and an action is to decrease the ROP to circulate out the gas. By increasing the density of the drilling mud to reduce the volume of gas flow into the well, there is a danger of bursting the Våle formation and get lost circulation.[3, 4, 9-11].

2.1.2. Reservoir characterization of the Ekofisk field

The Ekofisk reservoir is made up of fine-grained limestone, composed of skeletal debris of pelagic unicellular algae, called cocolithophorids. These algae produced spherical calcareous

exoskeletons are called coccosphere. These coccospheres consist of a number of wheel-shaped elements called coccoliths. See figure 03.

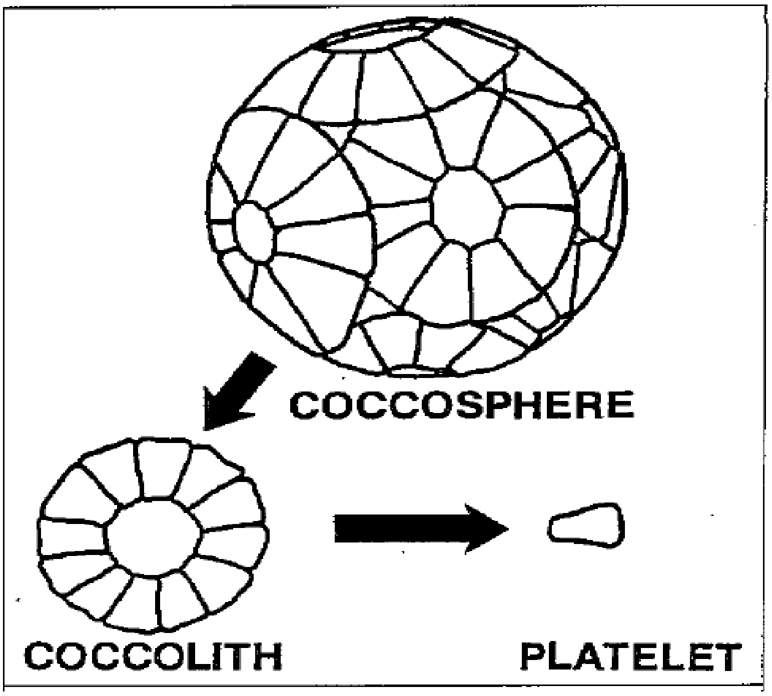


Figure 03. The development of the coccosphere to platelets [7].

Coccospheres are seldom preserved in the sediments. Complete coccoliths are relatively common, and the majority is broken up into their basic calcite crystal constituents, called coccolith platelets. See figure 04 below. The chalk also contains a variable amount of non carbonated material. Most of this material is silica, clay and minor amounts of pyrite, marcasite, dolomite, feldspar and siderite.[7]

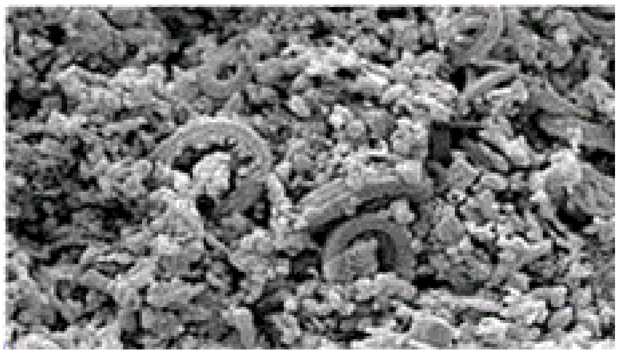


Figure 04. Coccoliths [12].

The Ekofisk reservoir is a high porosity, low matrix permeability and naturally fractured chalk [13].

Matrix porosity and permeability are related to the packing of coccolith platelets. The porosity varies locally. The local porosity can be as high as 48%. For both formations, the Ekofisk and Tor, porosity varies significantly both laterally and vertically and generally decreases towards the flanks and into the water zone.[7]. The average porosity in the best layers (TA, EL and EA) is around 30%-45%. This porosity depends on the location of the layer at the structure. The value of the permeability is few tens of mD (milli Darcy) in matrix. The crack-permeability is much higher, but this permeability is difficult to quantify.[2, 9].

The productive intervals of the Ekofisk formation are divided into two upper geological layers (EA and EM) and one lower layer (EL) [2].

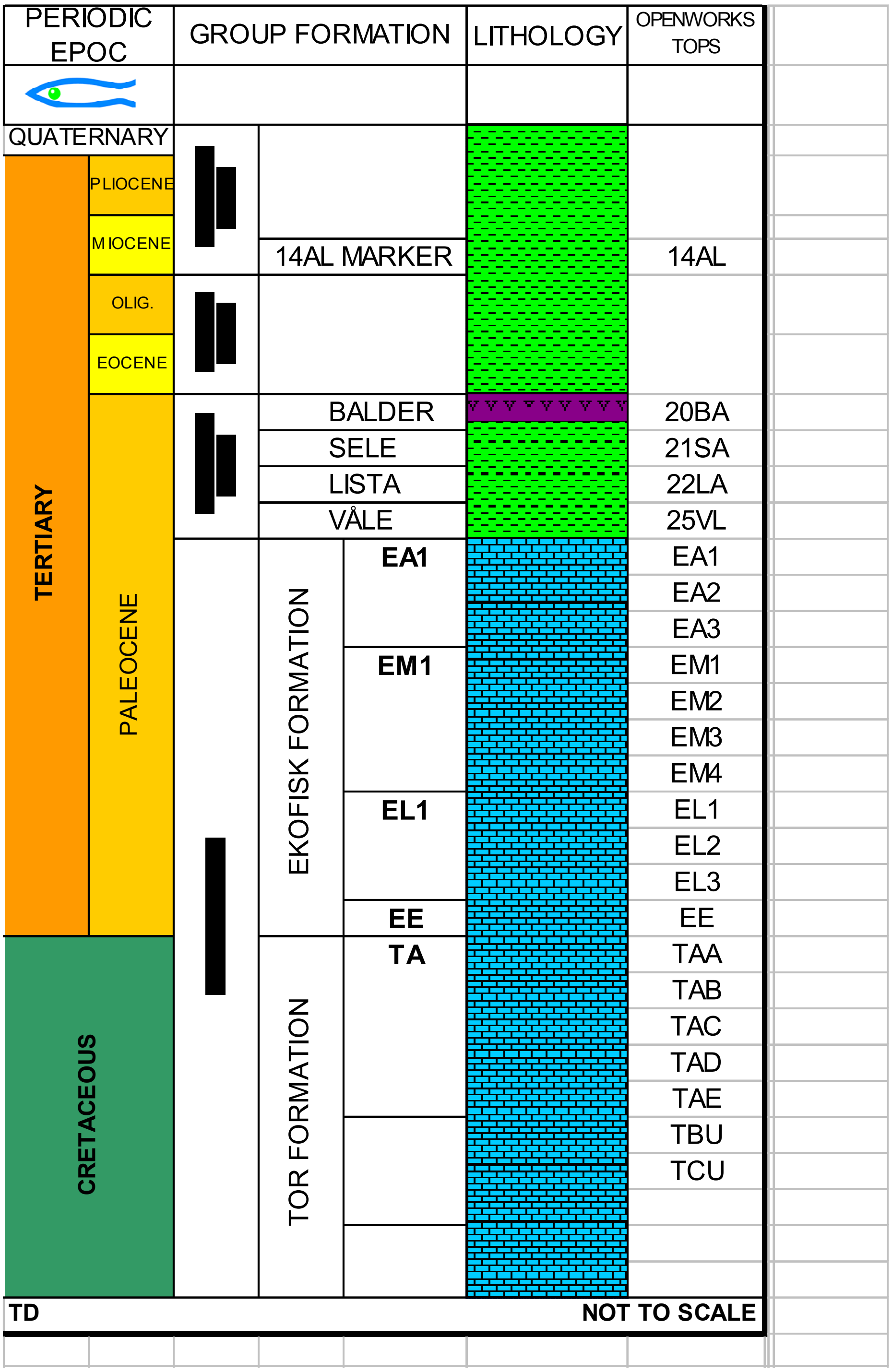


Figure 05. Stratigraphic column [9].

Fluid flow is mostly governed by distribution, orientation and interconnectivity of the natural fractures [13]. The fracture structure in the Ekofisk formation is primarily tectonic, while fractures in the Tor formation are predominantly associated with stylolites [2]. Fracture spacing in the Ekofisk field varies between 16.4 and 328.1 ft and the fracture dip is between 65 and 80 degrees. Approximately 40% of the upper Ekofisk is un-fractured, with layer EM being least fractured.[14].

There are over 300 fault planes mapped in the Ekofisk field. The faults with the largest throws, the NE-SW faults, have been designated as non-neighbor connection faults, which mean that these faults allow communication across different bed boundaries. Numerous faults are defined in the reservoir simulation model. These faults are strik-slip faults and reverse faults, which are typically less than 50 ft.[13].

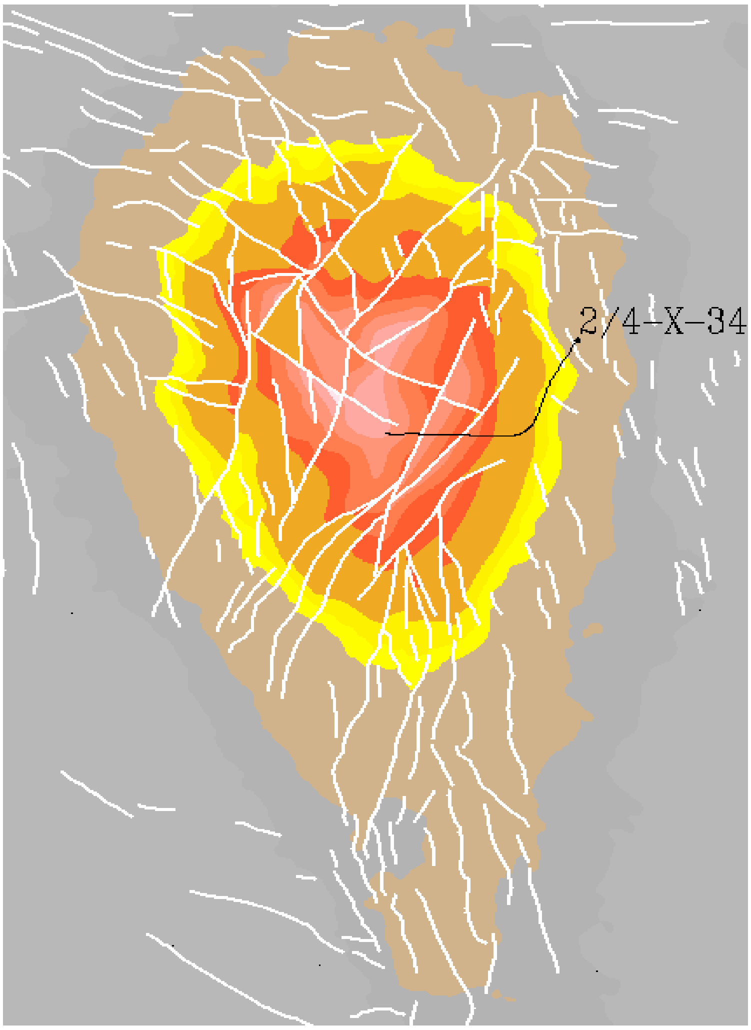


Figure 06. Faults top reservoir at Ekofisk with well 2/4-X-34 [9].

2.1.3. Overburden on Ekofisk field, the Miocene layer

The crestal part of the Ekofisk field is totally obscured on seismic due to presence of gas in the overburden, the same gas that is creating challenges when drilling the overburden section. The gas originates from the reservoir, and has been migrating along fractures and faults to a level in the Miocene section, where it seems to become trapped. This level is commonly referred to as the Lower Miocene Marker (called 14AL), which probably represents a geologic unconformity. The formations deposited after this event, seems to be less fractured than the overburden section below, which probably explains why the gas is trapped, as these layers will be impermeable to flow.[9].

As earlier explained, the Ekofisk is an anticlinal structure, and from seismic it can be seen that this structure have been forming up to Miocene/Pliocene, as also this level has the anticlinal shape. This means that even on Lower Miocene level (14AL), there is a pronounced anticlinal structure acting as a 4-way closure, in other words a hydrocarbon trap. The 14AL structure is typically located at 5300 ft TVDSS at the crest, while out on the flanks it is a few hundred feet deeper. It is likely the gas concentrations will be higher on the crest compared to the flank.[9].

2.2. Rock mechanics

2.2.1. Behavior of chalk

The chalk was deposited in the Norwegian sector in the North Sea between 100 and 65 million years ago. The Ekofisk layers (Ekofisk and Tor formations), were deposited 80-60 million years ago. The accumulation rate of the plankton over a period of 20 million years was 0,03-0,07 ft/years. These materials had a very high initial porosity, as high as 70 %. About 60 million years ago dramatic climatic changes occurred in the sea, which caused the accumulation of the plankton to stop. In stead of chalk deposition shale and clay, was deposited above the chalk layers. Normally, these layers would be compacted due to the heavy weight, which causes reduced porosity. Two aspects prevented this to happen; the overburden shale and clay layers became almost impermeable to fluid flow. At the same time the oil started to migrate upwards into the chalk layer from more profound shale formations. The oil displaced the water in the chalk layer, and then it was trapped in the impermeable layer. This resulted in a very high pressure in the chalk layer, because it could not migrate further.[10].

Chalk is an important reservoir rock in the southern part of the North Sea. The chalk at the Ekofisk is characterized as low permeable (1-3mD) with high porosity (40-50 %), and the reservoir temperature is about 266^0F. During the production phase by pressure depletion, increased reservoir compaction has been observed due to the very high chalk porosity. This compaction has been regarded as a contribution to the drive mechanism for oil recovery. It is also well known that the chalk becomes weaker as the oil is displaced by water. This phenomenon is called water weakening of chalk. This mechanism is not fully understood. This water weakening effect is illustrated by figure 07. The chalk is 100 % saturated with decane and kept at constant stress level of 20 MPa. The strain increases dramatically as the core is invaded by water. This water weakening effect takes place independently of type of water. Fig 07 shows how the chalk yields for different saturation fluids. The water-wet condition is weaker than the dry-wet condition. The mechanical strength of chalk is linked to the stability of the inter-granular contacts, which is known to be very weakly cemented. Recent studies have shown that chalk, flooded with distilled water is considerably stronger than the chalk cores flooded with artificial seawater. At high temperature, Mg^{2+} will substitute

Ca^{2+} at the chalk surface to form $MgCO_3$, which will affect the mechanical stability of chalk. This reaction is known as dolomitization. Another test done to determine the strength of the chalk is a tensile test, called the Brazilian test. It was seen that the water weakening effect also affects the tensile strength, see figure 07. The test result, (M.V. Madland. et.al) shows that the tensile strength is lowest for the water saturated chalk, and strongest for the dry chalk. To summarize this, except for the "dry" chalk, all tests, both Brazilian and triaxial tests show a decreasing resistance with increasing temperature. The magnitude of the strength varies with type of chalk and with saturation fluids. When comparing with other rocks, like granite, it shows decreasing strength with increasing temperatures.[11, 15, 16].

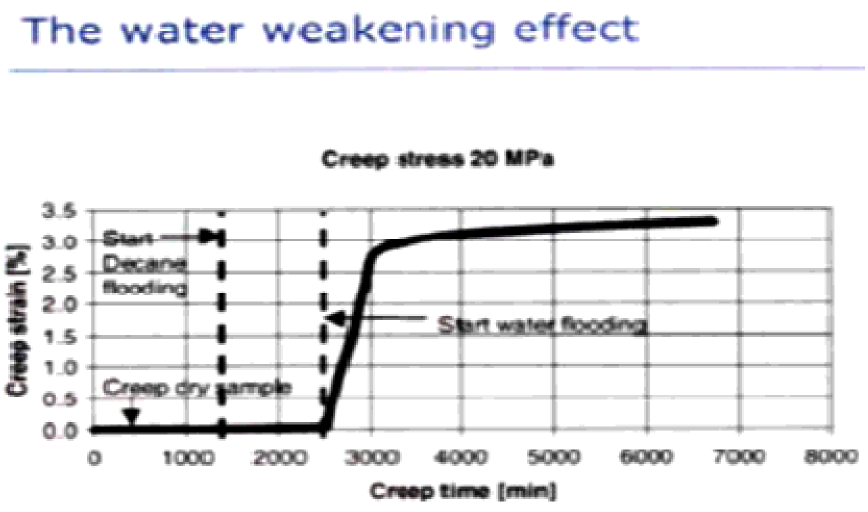


Figure 07. Water weakening effect [17].

The soft nature of the biogenic sediments is one of the reason for the natural fracture in the reservoir [18]. The salt tectonic is the main driving mechanism for fractures in the reservoir and the overburden [9]. During the production of the oil and gas from the reservoir the pore pressure in the reservoir was reduced. This gives a higher stress regime in the overburden.[10]. The change in the stress regime in the overburden may cause different or another fractures and also different fault planes. This may be a reason for increased migration of gas in overburden.

2.2.2. Effective stress

As written above, when producing oil and gas, the pore pressure in the reservoir will decrease. The result of the reduced pore pressure is an increase in effective stress. Effective stress is;

$$\sigma^{'} = \sigma - \alpha \cdot P_o$$

Where the $\sigma^{'}$ is effective stress, σ is total stress, α is Biot constant and normally range from 0 to 1, and P_o is pore pressure.[19].

The definition of stress is force divided by area. $\sigma = \dfrac{\Delta F}{\Delta A}$

Can split the force component into two units, ΔF_N and ΔF_S, normal force and shear force respectively. The forces ΔF, ΔF_N and ΔF_S, depend on the location of area ΔA.

The normal stress; $\sigma = \dfrac{\Delta F_N}{\Delta A}$

The shear stress; $\tau = \dfrac{\Delta F_S}{\Delta A}$

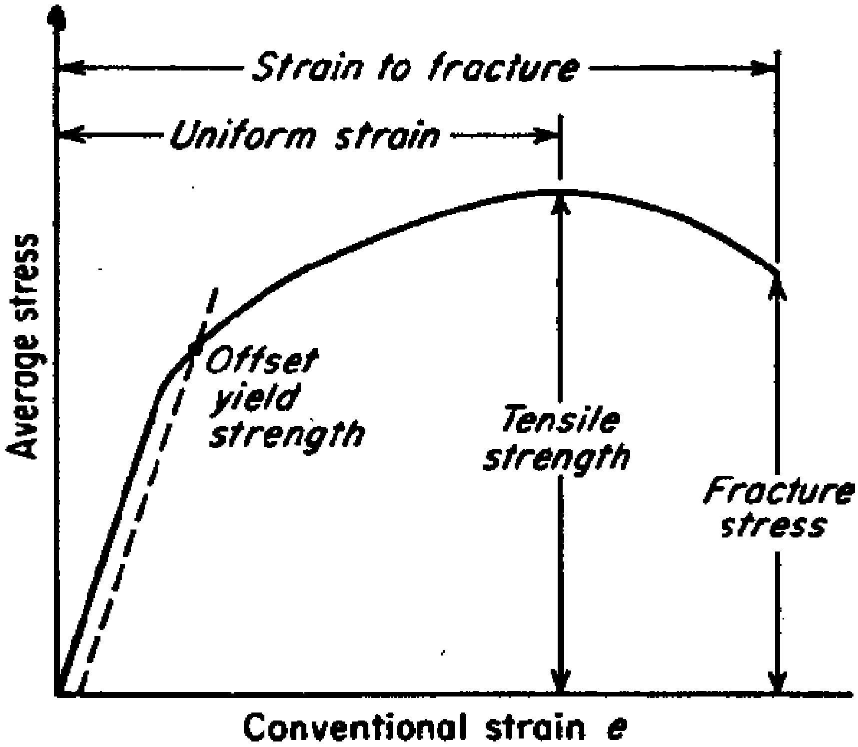


Figure 08. Stress vs. strain [20].

The principal effective stresses may increase at different rates during pore pressure draw down, depending on the boundary condition on the reservoir, size, geometry, depth of the reservoir, and other parameters. During 30 years of petroleum production pore pressure throughout the field has been reduced. The decline in pore pressure has led to an increase in the fraction of overburden load that must be supported by structurally weak chalk matrix, which caused significant reservoir compaction.[19].

To give a complete description of the stress state at a point P, it is necessary to identify the stress related to surface oriented in three orthogonal directions. There are all together nine stress components related to the point P.

The stress tensor is written as; $T = \begin{bmatrix} \sigma_{xx}\sigma_{xy}\sigma_{xz} \\ \sigma_{yx}\sigma_{yy}\sigma_{yz} \\ \sigma_{zx}\sigma_{zy}\sigma_{zz} \end{bmatrix}$

Can divide the stress components into stress invariants, which is unaltered during any change of coordinate axes.

$$I_1 = \sigma_x + \sigma_y \sigma_z$$

$$I_2 = -(\sigma_x \sigma_y + \sigma_y \sigma_z + \sigma_x \sigma_z) + \tau_{xy}^2 + \tau_{yz}^2 + \tau_{zx}^2$$

$$I_3 = \sigma_x \sigma_y \sigma_z + 2 \cdot \tau_{xy} \tau_{yz} \tau_{zx} - \sigma_x \tau_{yz}^2 - \sigma_y \tau_{zx}^2 - \sigma_z \tau_{xy}^2$$

These stress invariants is then used to calculate the principal stresses. For any state of stress where the shear stresses vanish, is called principal stresses.

By using this equation; $\sigma^3 - I_1 \sigma^2 - I_2 \sigma - I_3 = 0$, find the principal stresses $\sigma_1 > \sigma_2 > \sigma_3$

It is convenient to reorient the coordinate system so that the x-axis is parallel to the first principal axis and the y-axis parallel to the other. Then the stress σ and τ in a general direction θ relative to the x-axis becomes

$$\sigma = \frac{1}{2}(\sigma_1 + \sigma_2) + \frac{1}{2}(\sigma_1 - \sigma_2)\cos\theta$$

$$\tau = -\frac{1}{2}(\sigma_1 - \sigma_2)\sin 2\theta$$

$$\tan 2\theta = \frac{2\sigma_{xy}}{\sigma_{xx} - \sigma_{yy}}$$

These corresponding values can be plotted in a diagram, called Mohr's circle. Mohr's circle is a very useful tool to analyze the condition of failure in rock. The radius of the circle is $(\sigma_1 - \sigma_2)/2$ and the center is $(\sigma_1 + \sigma_2)/2$.[10, 19, 21, 22].

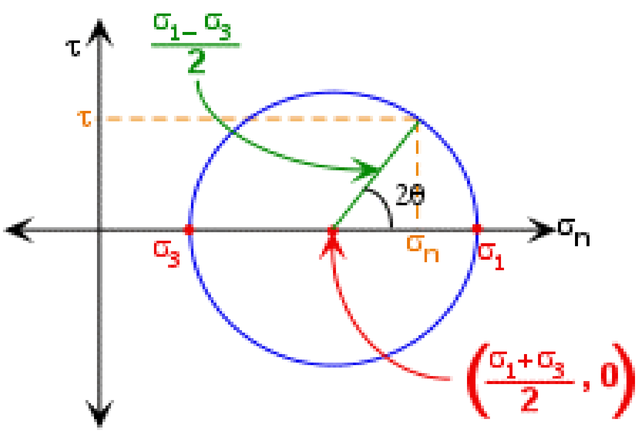


Figure 09. Mohr's circle [23].

After determining the magnitude of the principal stresses, it is convenient to determine the horizontal stresses which give an indication of the failure mechanism in the bore hole. When a well is drilled in a formation, stressed solid material is removed and replaced with a fluid under pressure. This stress alternation may lead to failure in the formation and consequently large operational problems in the well. In order to examine the stress in the formation, it is convenient to express the stresses and strains in cylindrical coordinates.[22].

In rock mechanics, one is concerned of the rock properties, but stress and loading are independent of the rock properties. Investigate the stresses in a borehole in this section. The model which will be presented in this chapter was first derived by Kirch in 1898. It is a simple plate with a hole in the middle. The plate represents the rock formation. Initially there is no hole. Since the loading is equally on all sides, the plate has a uniform stress state. This stress state is called the in-situ stress state. After drilling a well the stress state will change, and are dealing with two main stress categories:

- The in-situ stress
- The stress around the hole

The Kirch equations are very time consuming, will therefore list the equations derived from the Kirsh equations by Aadnøy.[24]:

Radial stress: $\sigma_r = P_w$

Tangential stress: $\sigma_\theta = \sigma_x + \sigma_y - P_w - 2(\sigma_x - \sigma_y)\cos(2\theta) - 4\tau_{xy}\sin(2\theta)$

Axial stress, plane strain: $\sigma_z = \sigma_{zz} - 2\gamma(\sigma_x - \sigma_y)\cos(2\theta) - 4\mu\tau_{xy}\sin(2\theta)$

Axial stress, plane stress: $\sigma_z = \sigma_{zz}$

Shear stress: $\tau_{\theta z} = 2(\tau_{yz}\cos\theta) - \tau xz\sin\theta$

$$\tau_{rz} = \tau_{r\theta} = 0$$

In application of the stresses above, assumes horizontal and in-situ stress field. However, the borehole assumes any orientation. Must transform these equations to the orientation of the borehole. Introduce two vertical horizontal stresses, σ_H and σ_h, and one vertical stress, σ_v. When transforming the stresses into a new coordinate system, use these equations:

$$\sigma_x = (\sigma_H \cos^2\phi + \sigma_h \sin^2\phi)\cos^2\gamma + \sin^2\gamma$$
$$\sigma_y = (\sigma_H \sin^2\phi + \sigma_h \cos^2\phi)$$
$$\sigma_{zz} = (\sigma_H \cos^2\phi + \sigma_h \sin^2\phi)\sin^2\gamma + \sigma_v \cos^2\gamma$$
$$\tau_{yz} = \frac{1}{2}(\sigma_h - \sigma_H)\sin(2\phi)\sin\gamma$$
$$\tau_{xz} = \frac{1}{2}(\sigma_H \cos^2\varphi + \sigma_h \sin^2\phi - \sigma_v)\sin(2\gamma)$$
$$\tau_{xy} = \frac{1}{2}(\sigma_h - \sigma_H)\sin(2\phi)\cos\gamma$$

All these equations are used in the failure analysis of the borehole stability problems. And by using the foregoing equations and the equations below, able to determine the capacity of the borehole fracturing and borehole collapse.

$$\sigma_r = P_w$$
$$\sigma_2 = \frac{1}{2}(\sigma_\theta + \sigma_z) + \frac{1}{2}\sqrt{(\sigma_\theta - \sigma_z)^2 + 4\tau_{\theta z}^{\ 2}}$$
$$\sigma_3 = \frac{1}{2}(\sigma_\theta + \sigma_z) - \frac{1}{2}\sqrt{(\sigma_\theta - \sigma_z)^2 + 4\tau_{\theta z}^{\ 2}}$$

After calculating the principal stresses above, the subscripts are often interchanged such that 1 always refers to the maximum compressive principal stress, 2 to the intermediate and 3 to the least principal stress. The borehole will fracture when the minimum effective principal stress reaches the tensile rock strength, σ_t. Expressed by: $\sigma_3' = \sigma_3 - P_o \leq \sigma_t$

Collapse is associated with low borehole pressure. At low borehole pressure, the tangential stress becomes larger, and a stress contrast between the radial and the tangential stress cause a shear stress. If this stress limit is exceeded, the borehole will collapse in shear.[24].

The minimum horizontal stresses vary across the field as a function of position of the structure. The lowest magnitude of minimum stress is on the crest and the highest are on the outer north and south flanks.[25].

These principal stresses and horizontal stresses give an indication of the failure mechanism. Change in the effective stress cause compaction and again change in stress regime in the overburden. This change in stress regime can cause an increase volume of gas in overburden.

2.2.3. Subsidence

The discovery of subsidence in November 1984 was quite unexpected. In the estimation days of Ekofisk, the reservoir compaction was linked to the productivity question. It was believed that if reservoir compaction occurred, productivity would decline as well. The production at the Ekofisk field declined from the production start due to the depressurization of the reservoir. This naturally drive mechanism was believed to decompress the reservoir, but it was not believed to subside the overburden at the Ekofisk field. The Ekofisk structure has a maximum subsidence of about 28 ft, and the subsidence rate has now decreased and stabilized at 0,33-0,49 ft/year.[1, 9, 26].

Reservoirs are dynamic systems that are constantly changing during their production life. There are three different factors that control how much a reservoir will compact. The change in effective stress is the driving factor. Hydrocarbon production of a reservoir will reduce the pore pressure and increase the effective stress. The decline in pore pressure has led to an increase in the fraction of overburden load that must be supported by the chalk matrix. It is also proven that compressibility will influence how much a reservoir will compact. For chalk, the compressibility is linked to the porosity. Higher porosity gives higher compressibility. And the third factor that influences the compaction is the depth of the reservoir. Thicker reservoir layers will give more compaction.[10].

During subsidence, the reservoir and the overburden are compacted. This compaction model is based on the effective stress principle. This model decomposes the total stress into a rock matrix stress and a pore pressure component.

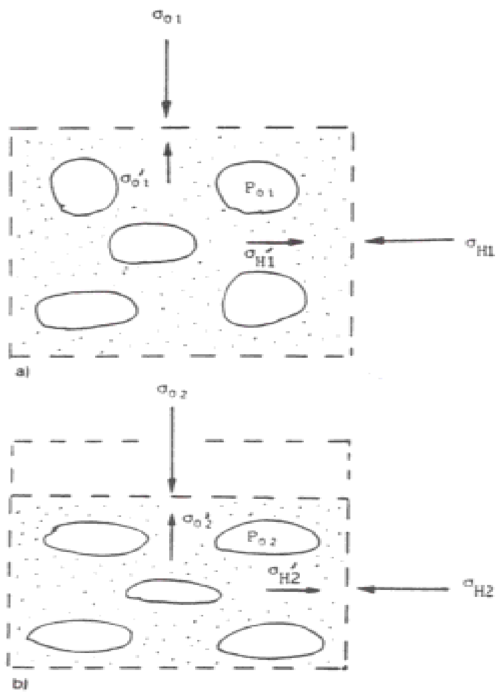


Figure 10. Rock before and after the pore pressure are changed [27].

If the pore pressure has changed over time, we can estimate what effect this have on the fracturing pressure. If all data form a trend, we may interpret this as that all data have the same origin. Aadnøy (1991) derived an easier and more understandable model for this “back stress”, which describe how the pore pressure influences the fracturing pressure. Fig 10 show a rock both before and after the pore pressure has been changed. Assuming the overburden stress remains constant, and no strain on the sides of the rock is applied, we can calculate the changes in the horizontal rock stress. Since the overburden stress is constant and the pore pressure is e.g. lowered, the rock matrix must take that load held by the initial pore pressure. The horizontal stress increase is:

$$\Delta\sigma_a = {\Delta P_0 (a - 2\nu)} / {(1-\nu)}$$

The following fracture pressure can be calculated:

$$\Delta P_{wf} = \Delta P_0 {(1-3\nu)} / {(1-\nu)}$$

By plotting these raw data, see that the compaction corrected data nearly falls on a line, and can interpret that all data have the same origin.[27].

Previous work to quantify compaction and subsidence has concluded that pore pressure collapse is the dominant process [25]. There are other compaction failures beside pore collapse compaction, called Arch effect. The Arch effect is driven by the weight of the overburden which leads to reservoir compaction. Due to the arch of the reservoir, some of the overburden will transfer the weight to the flanks where the formation is less compressible. If the location of the reservoir is deep enough, narrow enough or if the overburden is stiff enough, the compaction can be reduced or prevented.[10].

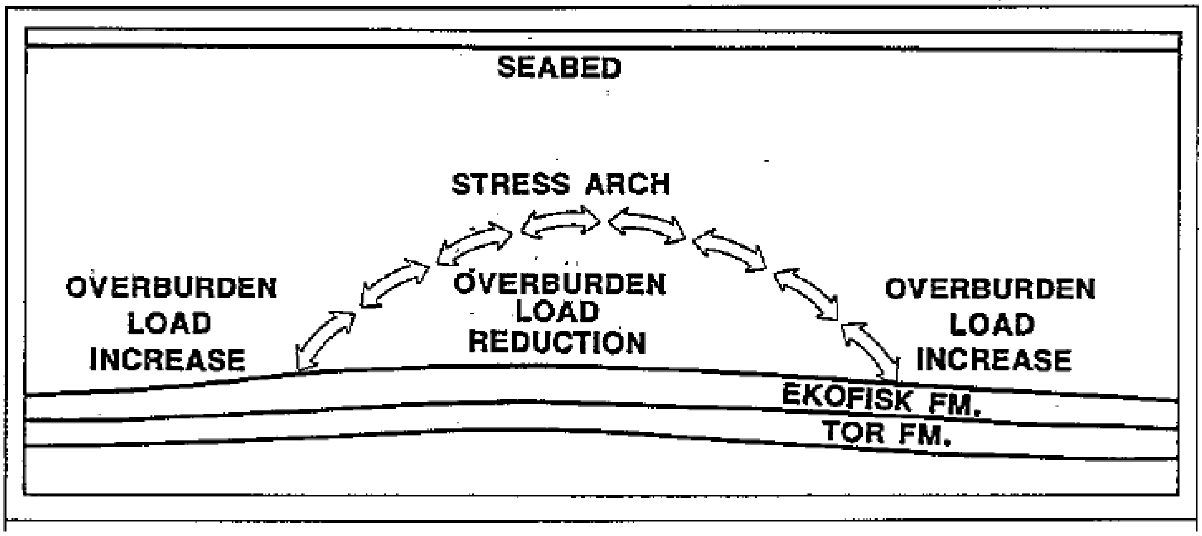


Figure 11. Arch effect [7].

Gain experience has shown that there is more compaction in the reservoir than subsidence at the seabed. This means that the overburden is "stretched", which will give a change in effective stress. This effective stress changes causes a change in stress regime in the overburden. Change in stress regime can lead to increased mobility of gas in overburden. This change can lead to fracturing of the formation in the overburden and give the gas increased mobility. As a result of changes in the reservoir pressure and associated compaction and subsidence, the in-situ stress field changes. Increase in effective stress normal to a fracture plane tends to close the fracture. Decrease in effective stress normal to a fracture plane (e.g., during water injection) tends to open the fracture. Shear displacement might also open fractures, at least initially.[1].

2.3. Operational parameters

2.3.1. Drilling mud

The drilling mud has three main functions:

1) Inhibit fluid flow and gas from formation into the well.
2) Removal of cuttings from bottom of the well and transport it to surface.
3) Deposit a thin mud-cake on the well bore wall, which restrict mud flow into the formation.[10].

There are three main different mud types, water-based system, synthetic mud system and oil-based system. Normally, the water-based system is used in the top section, called spud mud. Oil-based mud system is the most inhibitive polymer system. This is normally used during drilling of the lower sections.[10].
The mud has different capacities and parameters like, PV ~ plastic viscosity, YP ~ yield point and gel strength. They are all important parameters. The definition of plastic viscosity from (H.A. Barnes.et.al) [28]; "For a Bingham model, the excess of the shear stress over the yield stress divided by the rate of shear. η_p Pa.s" And the definition of yield point is by [6]: "The point where material gives way to excessive strain (such as elongation) without any further stress being applied".
To inhibit fluid flow and gas from the formation into the well, the hydrostatic pressure of drilling mud must exceed the pore pressure. The hydrostatic pressure in the well can be calculated as: $P_h = K \cdot TVD \cdot \rho_{mud}$, where K is a correlation factor due to which unit we choose. K equals to 0,052 for the Petroleum system and 0,098 for the SI system.
The transport of the cuttings is still one of the main functions of the drilling mud. Other functions of the mud are to cool down the bit and drilling pipe, and stabilize bore wall.[10].

For this thesis is focused on the density of the mud vs. gas flow from the formation into the well.

After considerable studies, an oil-based mud system was considered as a lower cost mud system that provided reduced drilling time and maintained well bore stability.
There is a clear advantage to drill if we can strengthen the well bore and drill at a higher mud weights without loosing fluid. Mud losses are a frequent problem during drilling. Losses occur when the mud weight exceeds the fracture resistance of the formation.[10].
To compensate for the gas flow into the well from the formation, it is normal to increase the mud weight. This can be a good solution at that particular time, but the increased mud weight can give problems later. As already mention, it is a balance between using high enough density of the mud to resist the high gas readings, and the danger of loosing mud into the formation. Losing mud can cause blowouts.
Blowouts and lost circulation due to abnormal and subnormal pore pressures have plagued the drilling industry since its initiation.[29].

The mud weight vs. depth and time, can give an indication of the amount of gas in the well.

2.3.2. Rate of penetration

ROP varies with:

- Weight on bit
- Rotary speed
- Bit type and size
- Drilling fluid properties
- Formation
- Bit hydraulics

The ROP has a significant impact on the gas level and mud weight in the borehole. A high ROP brings more gas (drill gas and gas contained in micro fractures around the wellbore) into the mud than a low one. In some cases the ROP has to be restricted in order to handle the drill gas related from the mud at the surface. A normal procedure to prevent influx of formation fluids into the wellbore is to increase the mud weight when the gas levels increases. This is not practical for wells at Ekofisk and partly Eldfisk because increased mud weight can cause fractures in the weak Våle formation which lies on the top of the Ekofisk reservoir. In summary, a high enough mud weight is required for well-control, but it has to be low enough to prevent fracturing the Våle formation.[3, 30]

2.3.3. Gas injection

Gas injection on the Ekofisk field started in February 1975. The injection of gas was done to permit full scale oil production during construction of a gas pipeline to Emden, Germany. Eight wells were initially completed for gas injection. All were located at the crest of the Ekofisk structure and gas injection was restricted to the Upper Ekofisk. After gas pipeline was running, gas injection was maintained in order to compensate for the excess gas being produced. Therefore, the injection rate decreased to the half, compared to the first three years, before the pipeline was set. From mid 1980, only “swing gas” was injected. In 1985, it was decided to escalate gas injection in an attempt to mitigate subsidence. It has been done several independent efforts to get information about gas migration and gas distribution as a part of the gas injection evaluation. They include time lapse well GOR field mapping, evaluation of gas tracer project, estimation of gas saturation profiles from pulsed neutron porosity logs, review of historical RFT pressure data and compositional analysis of the produced stream. Ekofisk wells unaffected by gas injection have been estimated to produce at a GOR of no more than 7000 – 8000 SCF/STB after reservoir pressure started to level out in 1985. Figure 12 below shows how the GOR has matured from 1979 to 1986 for wells having minimum 75 % Ekofisk formation contribution and for wells having minimum 75 %Tor formation contribution.

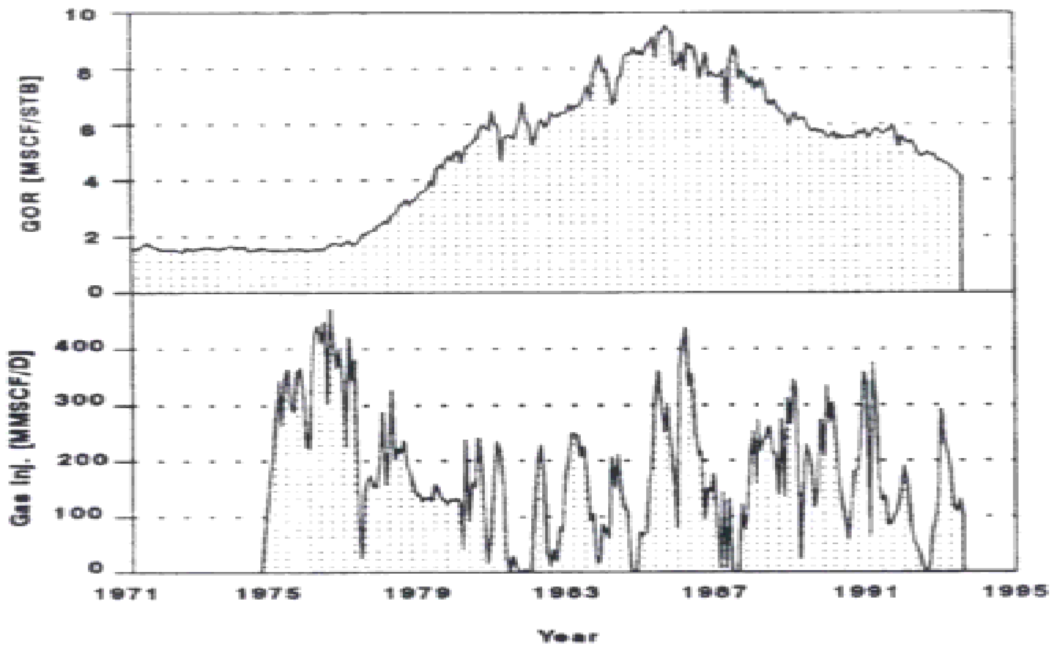


Figure 12. Maturation of GOR during time, from 19779-1986 [14].

The field GOR developed at the same time from 3500 SCF/STB in 1979 to 9000 SCF/STB in 1986 (Fig 12). The gas injection appears to have affected the production of the Ekofisk formation throughout most of the field. Two areas appear to be more affected, the south-western part around wells 2/4-C-01 and 2/4-C-16 and the 2/4-A-13 area. The wells in these two areas continuously show higher GOR compared to surrounding wells. In the northern part of the Ekofisk field it exist an area where the Ekofisk and Tor formation appear to be in communication. The communication could be due to permeable Tight Zone, faulted Tight Zone or both. This area is referred to as the “window” area.[14].

A gas tracer project was performed during 1986 to 1988. Radioactive tritium and krypton was injected as a slug. This project indicated communication between the Ekofisk and Tor formation across the Tight Zone in the northern part of the field. This was concluded since traced gas appears to have been produced in three Tor formation producers.
Gas migration may also be evaluated by studying gas saturation profiles in individual wells. When dry gas is injected into an oil reservoir, the gas will vaporize. This vaporization effect may show up as variations in the composition of the produced components. From the Ekofisk field a general trend of increasing API oil gravity with increasing GOR is observed while the gas component is fairly constant. The trend of lighter oil with higher GOR can be explained by additional condensate from the more dominating gas volumes.[14].

It has been done other field measurements to study if the gas injection has an influence on the gas in overburden. Other measurements; sponge coring, formation fluid sampling and gravimetric surveying. The results from these studies suggest that the gas is not forming a clear-cut gas cap, neither is it evenly distributed in all of the field or structural distributed. One of the main concerns upon starting gas injection was channeling of gas through highly conductive fault systems and fracture networks causing early gas breakthrough in producers offsetting the gas injectors. Conclusion of the evaluation, the weak correlation of GOR in some wells and the fact that five wells started to produce injected gas before the bubble point was reached, indicate that gas channeling is a factor at Ekofisk, though not a dominating factor.[14].

In the last few years, the GOR at the Ekofisk field has decreased in order to increased pressure buildup as a consequence of water injection [9].

2.3.4. Water injection

Seabed subsidence was first noticed at the Ekofisk field in 1984. This subsidence was a result of the production from the highly porous reservoir. Water injection was initiated due to the observed subsidence at Ekofisk in November 1987. The water injection wells are all the 2/4-K-wells and 2/4-W-wells. Water injection was started over a period of years, following a series of pilot injection projects. The water injection project in Ekofisk was expected to decrease and eventually stop subsidence. The reservoir pressure increased, but the subsidence did not stop. The seafloor subsidence rate at the central part of the Ekofisk field increased in the early 1990’s from low 0,82 ft/year in November 1990 to a peak of 1,38 ft/year in September 1993. Throughout 1994, subsidence rate declined from the peak of 1,38 ft/year to 1,15 ft/year. Rather than continue to decline as expected the rate increased slightly to 1,25 ft/year and remained nearly constant through 1998 as shown in figure 13.

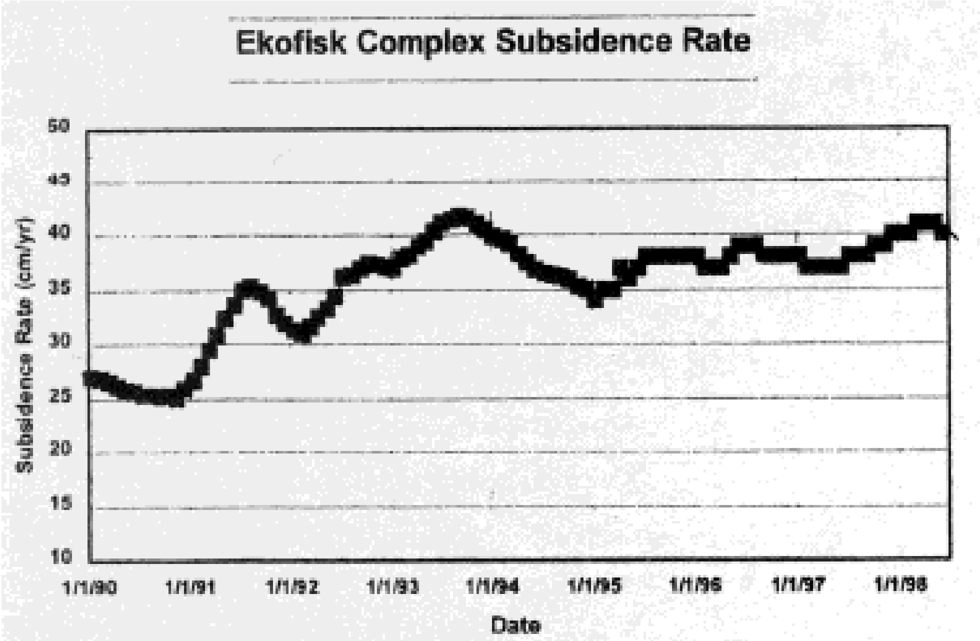


Figure 13. Subsidence rate at the Ekofisk Complex [26].

The subsidence rate in 2006 was between 0,33-0,49 ft/year. During 2006, the daily injection rate was between 400000 and 500000 bbl/day have been injected. Could injected more water, but many wells are not receptive for higher volumes because of poor mechanical conditions. Since the discovery of subsidence in 1984 extensive laboratory projects has been implemented to understand and quantify the behavior of Ekofisk reservoir chalk. The result of the ongoing laboratory test will be discussed in this thesis, rather than go thoroughly into the test program and methods. From the field observations and laboratory tests indicated that the reservoir rock behaved essentially elastically, despite the presence of formation brines. The mechanical strength of the chalk under stress decreased drastically when the cores were flooded with seawater at 266 ^{0}F compared to distilled water. Water flooding allows for seawater to gain access to calcite matrix, which then weakens dramatically. Why is the chalk water weakening? There exists different hypothesis around this problem. The latest result from the reservoir department at the University of Stavanger, have concluded that there is a chemical reaction between the chalk and the seawater. It is proposed as a hypothesis that the potential determining ions in seawater (Ca^{2+}, Mg^{2+} and SO_4^{2-}) area active in the water weakening process. The substitution of Ca^{2+} by Mg^{2+} at the chalk surface appeared to be crucial in the water weakening mechanism.[3, 9, 11, 15, 18, 26].

This water weakening hypothesis can give arise of change in stress regime in both reservoir and overburden, which again probably give change in fractures and faults.

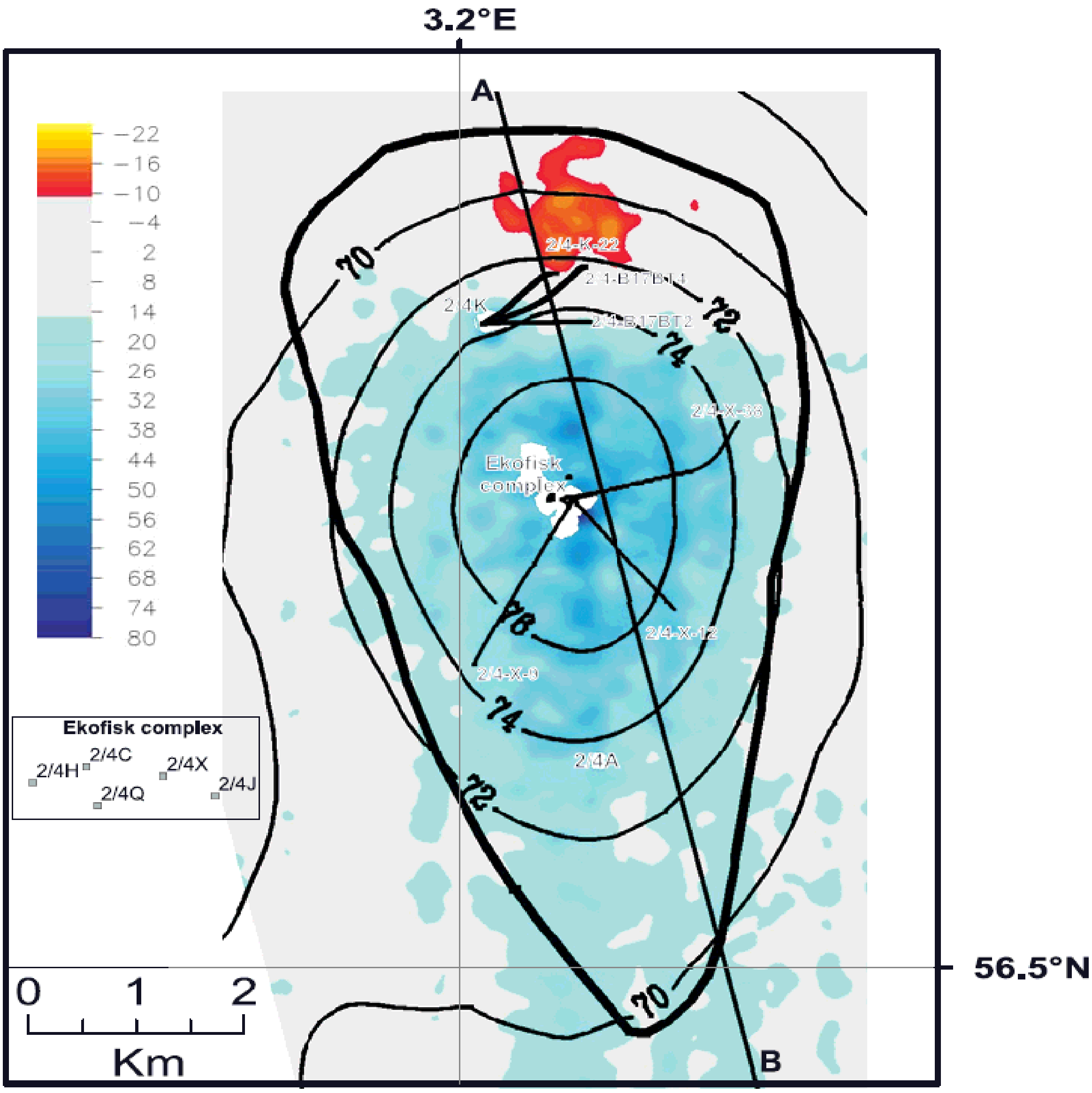


Figure 14. Differential bathymetry between 1999 and 2001 detailed surveys [31].

Water injection was initiated due to subsidence and the water is injected into the reservoir to maintain the reservoir pressure. On 7 May 2001, a seismic event of moderate size occurred in the southern North Sea. The event was strongly felt on the platforms. Since the seismic event was so strong, it might be expected that it would cause well failures. During 2002, while drilling from the northern 2/4-B platforms (see figure 14) in the northern flank of the field, abnormally high pressures were observed in the overburden at 6000-7000 ft TVD. This led to an investigation in that area. It was found that some of the wells had developed casing deformations, and closer investigation confirmed that due to a previous overburden collapse in one water injector (2/4-K-22, figure 14) was injecting 15000 barrels/day cold water into the overburden. Since the 2001 event, several wells in the northern part of the field around 2/4-K-22 have developed restriction at a depth of ~ 4500 ft. There is not necessarily a relationship between this restriction and event, but it is possible. [9, 31].

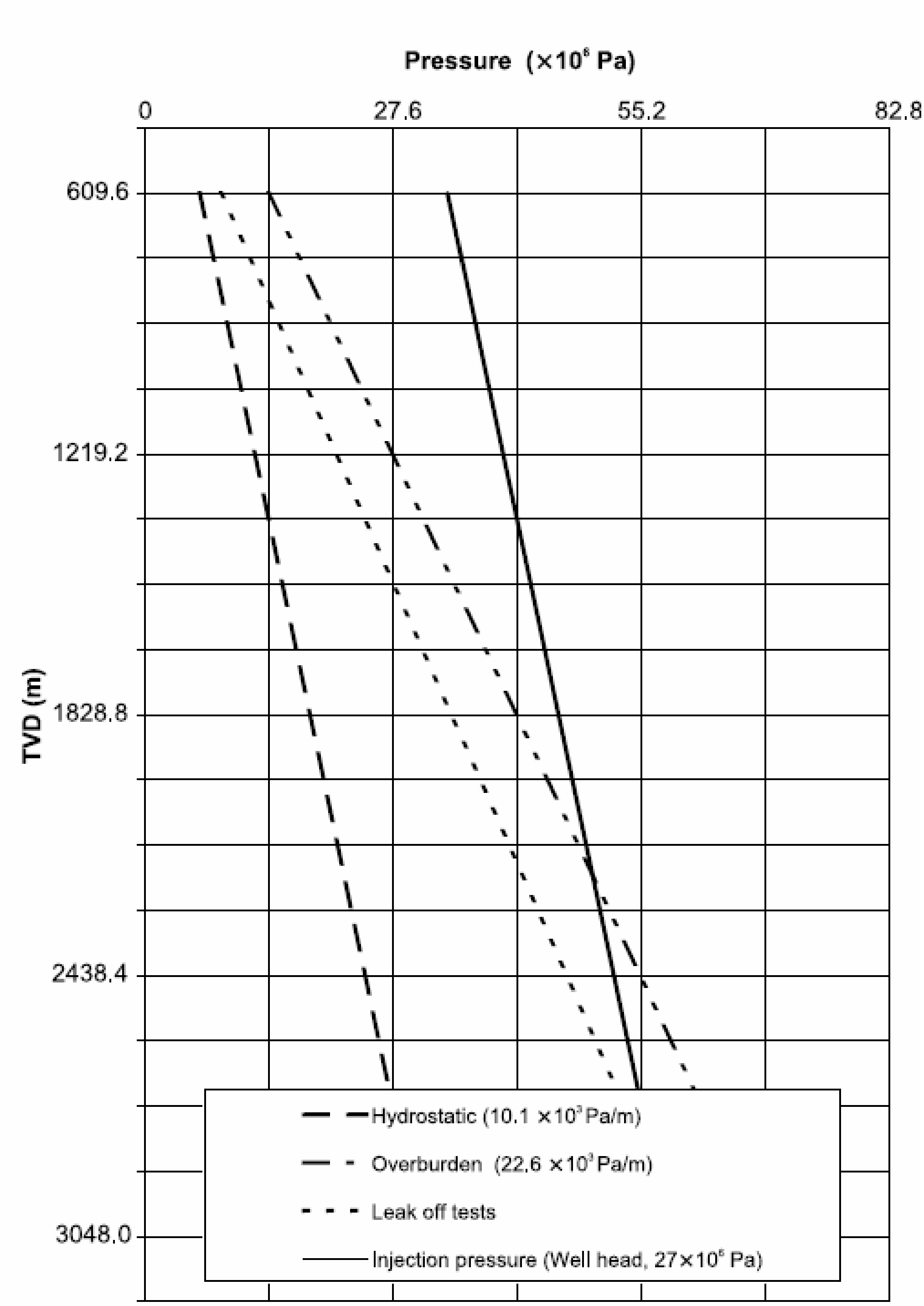


Figure 15. Pressure gradients for the Ekofisk overburden and injection pressure at K-22 [31].

Figure 15 shows how the water injection pressure was above the minimum horizontal stress derived from leak off test (LOT) data throughout the whole overburden. The water injection

pressure was above fracture pressure in the entire overburden and leading to fracture of the shale and gives space for water circulation.[31].

2.3.5. Cuttings injection

In response to concerns of the environmental effects of disposal of drill cuttings to the sea, ConocoPhillips began with cuttings re-injection late in 1996. An oil-based mud system was considered as a lower cost mud system that provided reduced drilling time and maintained well bore stability. However, it is also known that oil-based mud constitute an environmental hazard both to drilling crew and during disposal of cuttings. A detailed evaluation led to recommendation to use an oil-based mud system with cuttings re-injection. The injection process starts by the grinding pulverization of the cuttings. The cuttings are then pulverized to size less than 3 mm. After the pulverization and additive of different fluids to improve the injection properties, the cuttings are injected by dedicated wells, 2/4-X-38 (abandoned), 2/4-X-24 and 2/4-M-21. The location of well 2/4-X-38 is north-east (NE). The location of the 2/4-X-24 well is south-east (SE) and 2/4-M-21 well is south-west. This injection procedure is done at three potential levels, shallow (3000-4000 ft), intermediate (5000-6000 ft) or deep (8000-9000 ft). The deeper target has the lowest risk of fracturing to the surface and potential problems arising from the overburden gas are reduced as this target area would lie on the flank well away from major gas development. The injection of the cuttings in the formation in the overburden increases the pore pressure. If assuming constant matrix stress get a corresponding reduction of the effective stress. The results of a change in the effective stress are discussed earlier in this thesis.[9, 32].

2.3.6. Cementation

When drilling a well, need to secure and isolate the well. Wells are cased for different purposes:

1) Zonal isolation.
2) To secure the well when the hydrostatic pressure in the well is less than the pore pressure in the formation.
3) Secure the well for collapse and caving.
4) To form hydraulic seals for conservation and to isolate deep strata from the surface to protect the atmosphere and shallow groundwater sources, casings are cemented.[3, 10].

There exist two main different types of cementation methods which are regular and squeeze cementation, respectively. The regular cementation is done by pumping cement down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden.[33].

"Bad" cementation job can occur, which include mechanism as channeling, poor cake removal, shrinkage and high cement permeability. When bad cement jobs occur squeeze cement job are normally not performed unless there are barrier issues relating to the integrity of the wellbore. The cement is pumped/squeezed in the open spaces in the existing cement through perforations, or set as balanced cement plug. In short, oil and gas wells can develop gas leaks along the casings long time after production has ceased and the well has been plugged and abandonment.[3, 10, 25, 33].

Channeling can occur when setting balanced plugs because the cement slurry must displace the mud without mixing with it. Turbulent flow, pipe rotation, well deviation and a thin mud (low yield point) are important parameters in obtaining a successful job. The cement must fill the volume left in the hole when pulling out the stinger. If not, channeling can occur. In Ekofisk the most important factors in reducing the quality of both balanced plugs and casing cement jobs are gas migration and contamination of the cement slurry by mud. The transition from liquid to solid cement has to be reduced to a minimum to minimize gas channeling because solid cement loses its' hydrostatic head. One can also get channeling in the cement if it exist some kind of air bubbles in the cement, which will remain during the hardening.[3, 33].

Shrinkage of the cement may be the main reason for the gas leak along the casings. Shrinkage can occur in different situations. It can occur while the cement is in an almost liquid early-set state. Shrinkage can occur by water expulsion, high salt content formation lead to osmotic dewatering of typical cement slurries, dissolved gas, high curing temperatures and early set may also lead to shrinkage.[3, 33].

Cement will not bond in all cases. It will not bond to salt, oil sand, high porosity shale, and perhaps other materials [33].

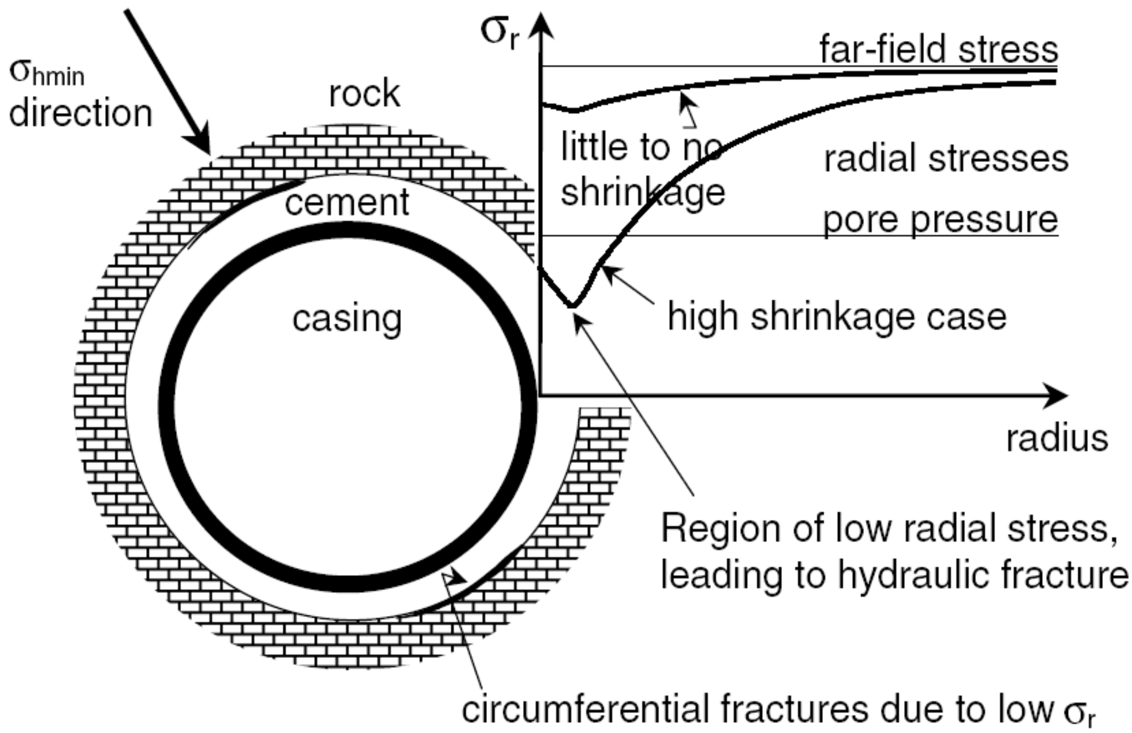


Figure 16. The effect of shrinkage near wellbore [33].

Figure 16 shows the effect of shrinkage on near-well bore stresses. Cement pressure $p_c(z) = \gamma_c \cdot z$, almost higher than p_o, but lower than $\sigma_{h\min}$ .Set occurs and a small amount of shear stress develops between the rock and the cement. The hydrostatic pressure in the cement is no longer transmitted along the annulus. Minor shrinkage will reduce the radial stress

between cement and rock because rock is stiff, and small radial strains cause relaxation of σ_r and increase in σ_θ. A condition of $p_o >$ than $\sigma_r(\sigma_3)$ is reached; i.e. the hydraulic fracture criterion. A circumferential fracture develops at the rock-cement interface.[33].
In the fracture, once solution gas in saturation is achieved; free gas at the top develops. The gradient is less than 0,145 lb/in^2, so there is an even greater excess driving pressure at the upper tip. In addition, this gradient effect tends to favor driving the liquid in the fracture back into the formation, and the fracture becomes more and more gas filled.[33].

All these phenomena's can be reasons for detected more gas in the overburden on Ekofisk.

2.3.7. NORSOK-D-010

The definition and course of action from NORSOK-D-010 [34]:

The function of the well barrier shall be clearly defined.
"There shall be one well barrier in place during all well activities and operations, including suspended and abandoned wells, where a pressure differential exists that may cause uncontrolled cross flow in the well bore between formation zones.
There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole to the external environment".
The well barriers shall be designed such that:

- It can withstand the maximum anticipated differential pressure it may become exposed to,
- It can be leak tested and function tested or verified by other methods,
- No single failure of well barrier or WBE leads to uncontrolled outflow from the borehole to the external environment,
- Re-establishment of a lost well barrier or another alternative well barrier can be done,
- It can operate competently and withstand the environment for which it may be exposed to over time,
- Its physical location and integrity status of the well barrier is known at all times when such monitoring is possible

ConocoPhillips (COPNO) do not have any specific requirements when drilling under conditions of great amount of gas in the wellbore, but there exists a drilling manual which describe the drilling operations under these operations [3].

“Primary well control is provided by the hydrostatic pressure of a column of fluid that is greater than the formation pressure. Insufficient pressure in the wellbore may allow an influx of formation fluids to enter the wellbore. The mud weight must be managed to prevent an influx.” [35].

In addition, this mud weight must also be high enough to prevent collapse of the formation [3].

Some companies have strategies which say that if it exist more than 5 % gas, needs to increase the mud weight. If there is more than 3 % gas, can not take connection with the drill pipe. COPNO do not have any specific requirements like this. ConocoPhillips’ strategy is to circulate out the gas in stead of increase the mud weight which can fracture the formation.[3].

3.EMPIRICAL DATA AND ANALYSIS

3.1. GENERAL

The main task for this thesis is to do an investigation of the development of the gas in the overburden of the Ekofisk field. It seems like there is more active gas in the overburden in recent time compared to some years ago. COPNO's interest is to determine if there is more gas in the overburden in recent days, whether regional differentiations exist and determine at what depths tends to occur the gas in the overburden at the Ekofisk field.

The method used in this thesis has been to collect and prepare mud gas data to comprehensible figures and graphs. In the end of this thesis I will give a conclusion of the development of the gas in the overburden. The drilling mud which comes to surface in return from the wellbore is sent through a separator where the gas is separated from the mud and the cuttings. The gas values are then recorded and stored by Sperry Sun, Halliburton. The gas values are then transformed and related to the actual depths to the drill bit. The stored data originates from the database, called OpenWorks (OW), which holds all Geological and Geophysical (GG) type data for Ekofisk (see appendix A). From OW, maps and plots are generated as figure 17 indicates.

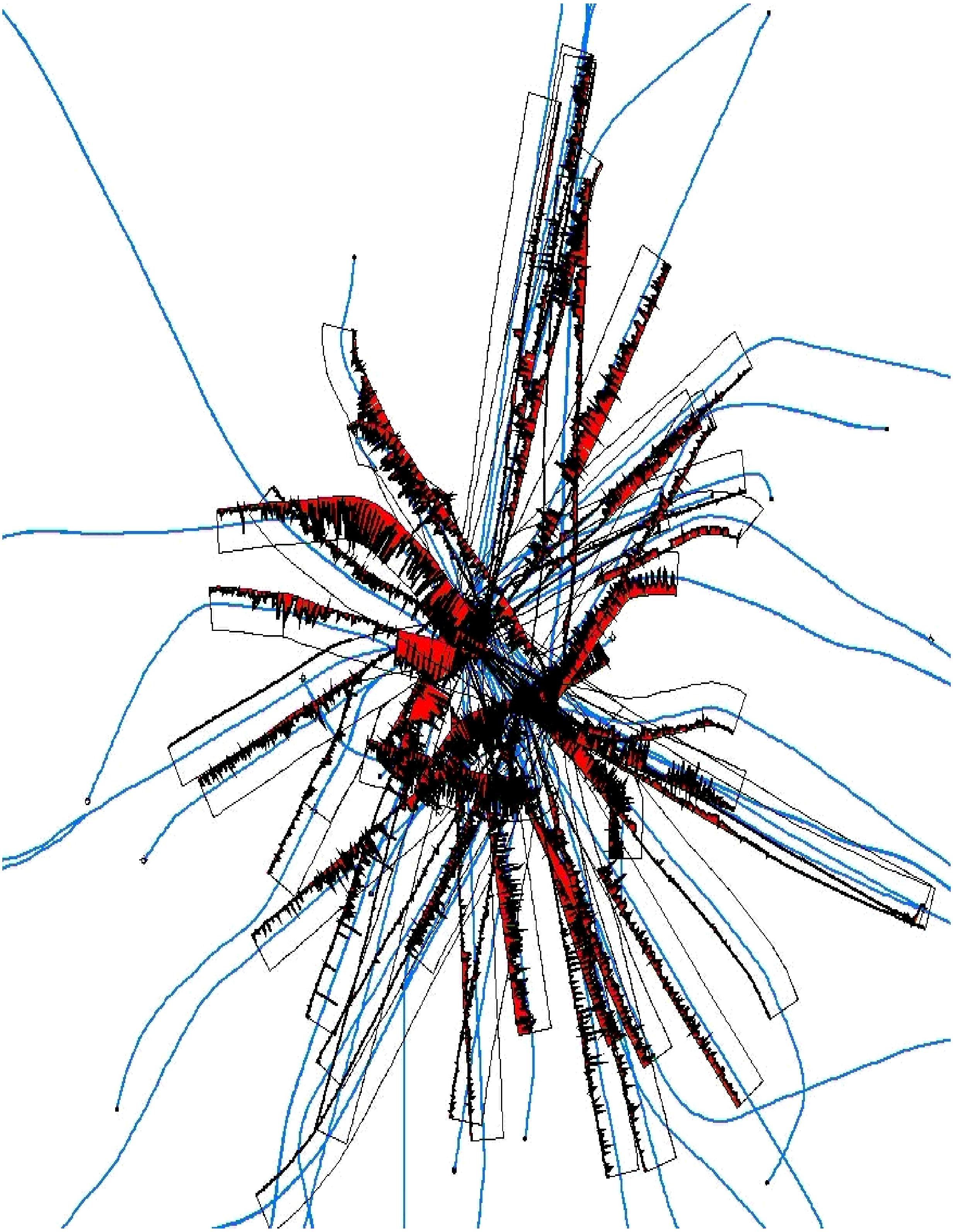
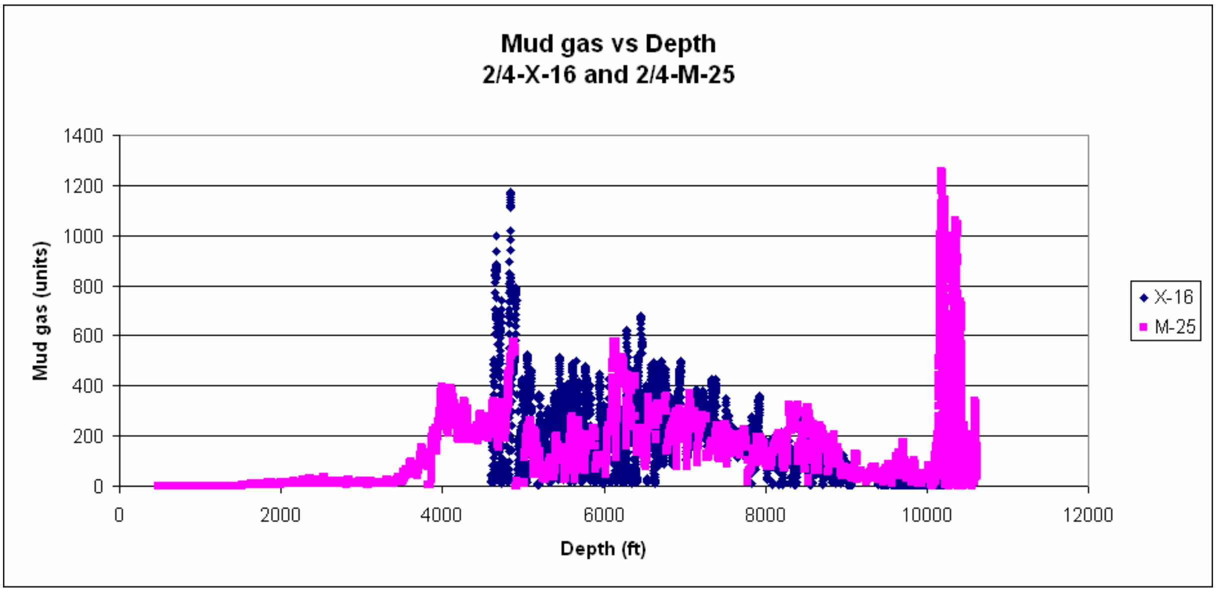


Figure 17. Well path with mud gas logs for 2/4-X and 2/4-M- wells

The map in figure 17 used in this thesis consists of the well paths for the different wells and the corresponding gas logs. This map with the logs is not giving a correct picture with respect to the problem to be addressed. The main task is to determine if there is more gas in the overburden now than earlier. So, the mud gas values in OW are edited, the depths are referenced to Mean Sea Level (MSL) and plotted in graphs using Excel.

3.2. THE DEVELOPMENT OF THE GAS IN THE OVERBURDEN

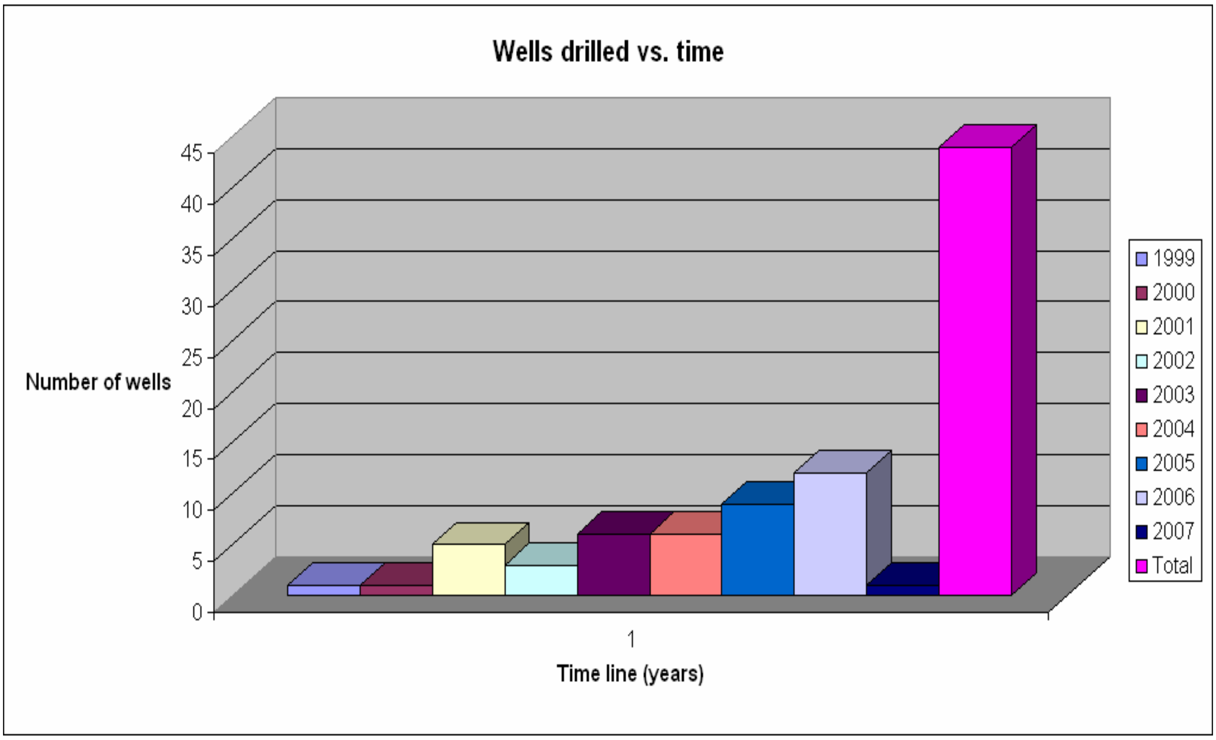
It can be interesting to look at the graph that includes both the oldest and newest wells in the same graph. This graph can give a presentation of the development of the gas in the overburden over time. It was true that overburden gas increased through time, the curve of the newest well should be overall higher compared to the oldest well. See graph 01.



Graph 01. Mud gas vs. Depth, 2/4-X-16 and 2/4-M-25

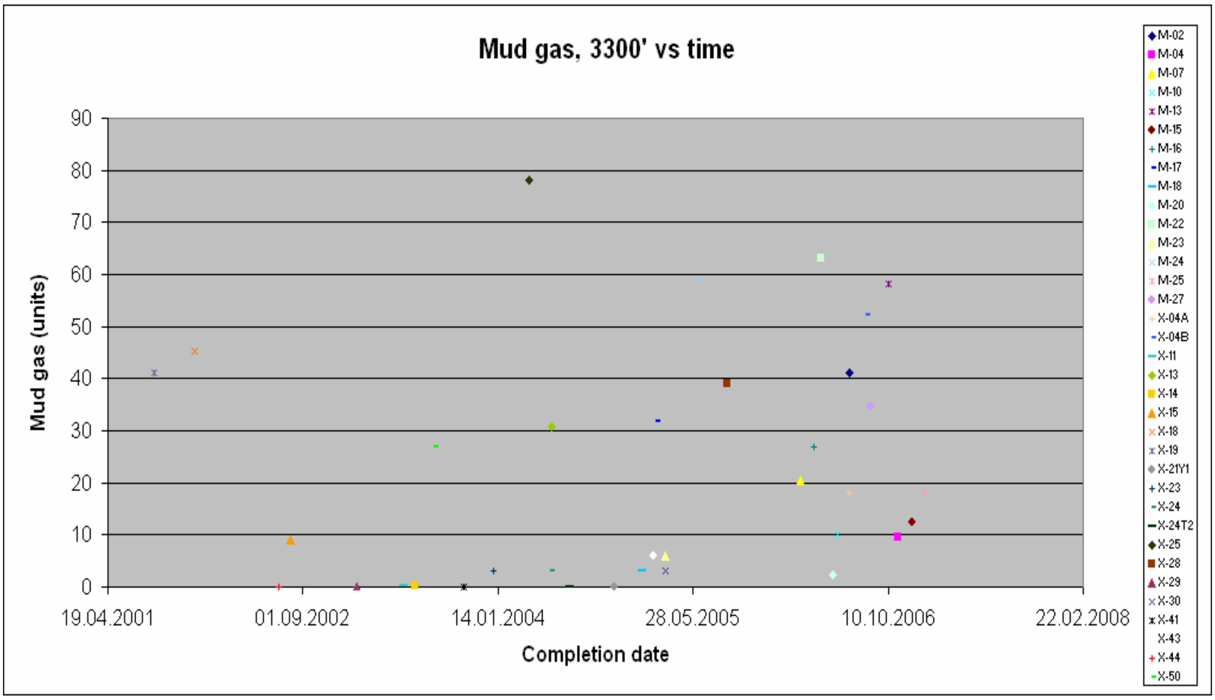
It is difficult to see any trend of increasing volume of gas in the overburden over time from this graph. This graph consists of the oldest well COPNO has any recordable data of, 2/4-X-16, which was drilled in 1999, and the newest well, 2/4-M-25, which was drilled in 2007. This graph does not indicate any increasing volume of gas in the overburden over time, rather the opposite. This could be explained by the location of the well (like in two different areas), but both these wells are drilled in the same zone, the SE area of the Ekofisk field. It can be a coincidence that this graph indicates less volume of gas in the overburden of the Ekofisk over time. The graph still does show a trend which is opposite of the experience during drilling of the new wells and further investigation and development of other graphic presentation is needed.

COPNO have unfortunately only stored the gas values for the wells from 1999. This time range is statistically not sufficient to give accurate conclusions, so the analysis and comments in this thesis are based on the data available. During this analysis, I have been studying approximately 50 wells distributed from 1999-2007. The distribution can be seen in the graph 02 below.

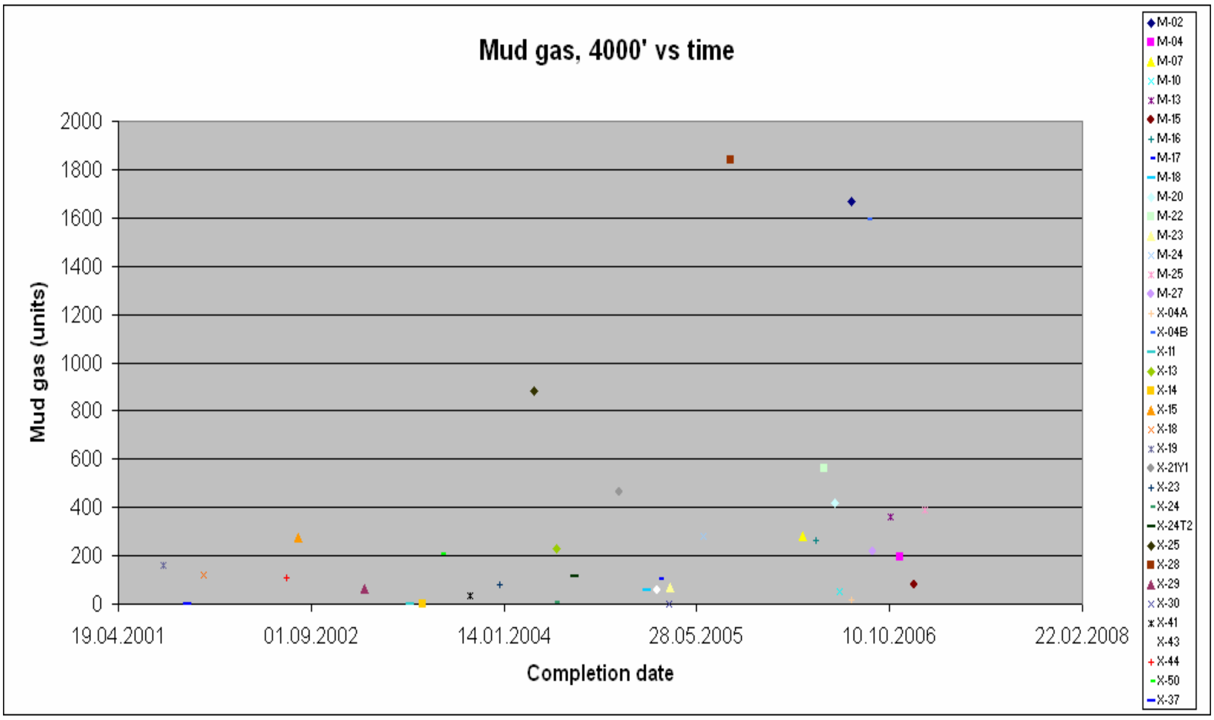


Graph 02. Distribution of wells drilled over time.

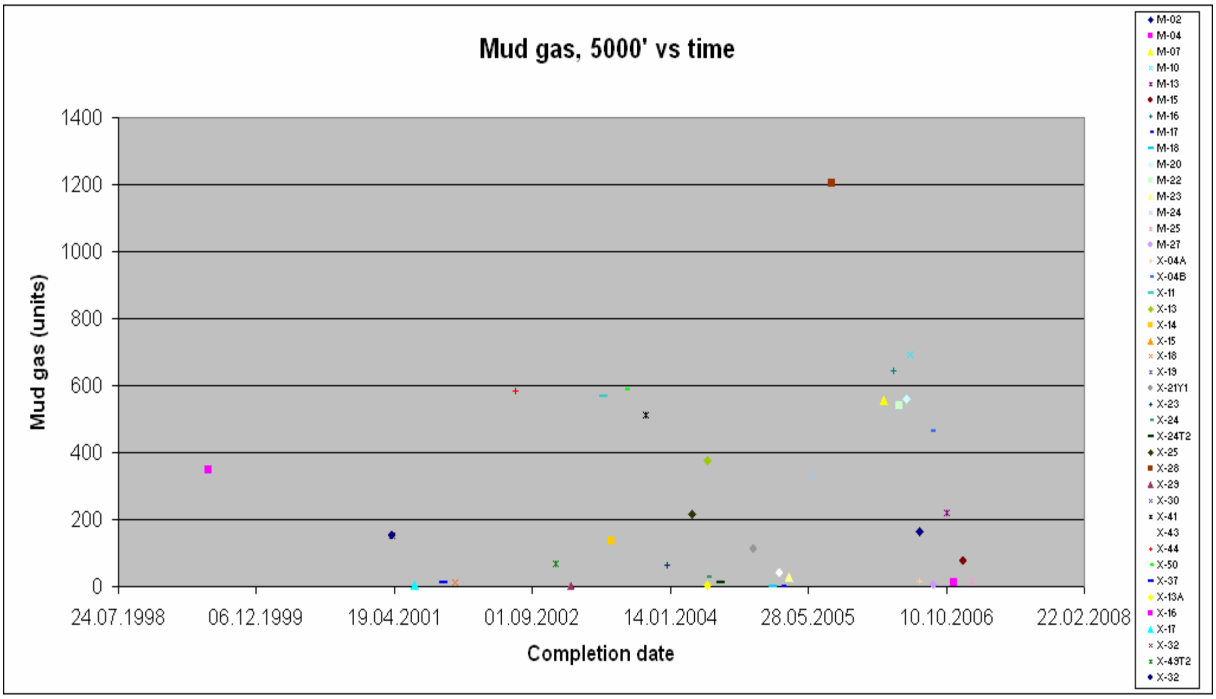
As written in the start of the thesis, the main purpose of this project is to determine if there is more active gas in the overburden in recent time compared to some years ago. For this investigation the gas values need to be plotted against completion date to see the development of the gas in the overburden. To visualize the development of the gas in the overburden, I have decided to plot the gas in depth-intervals, like 3300, 4000, 5000, 7500 and 9000 ft vs. completion date.



Graph 03. Mud gas, 3300 ft vs. Completion date



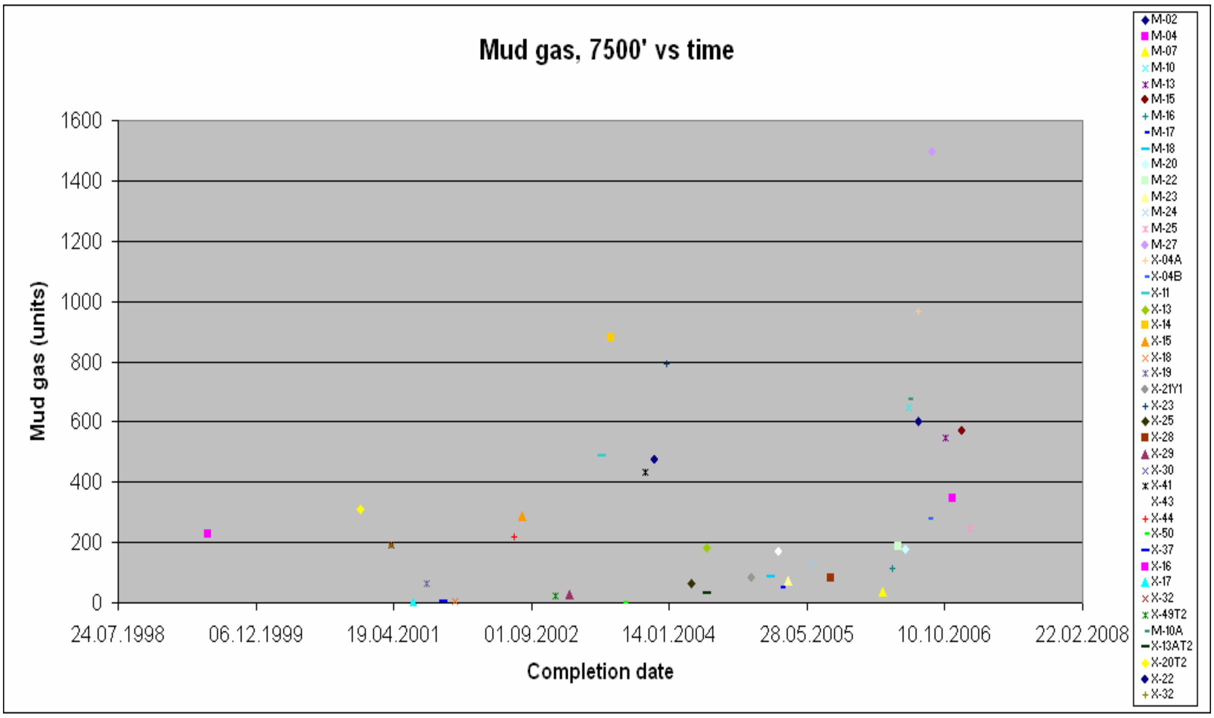
Graph 04. Mud gas, 4000 ft vs. Completion date



Graph 05. Mud gas, 5000 ft vs. Completion date

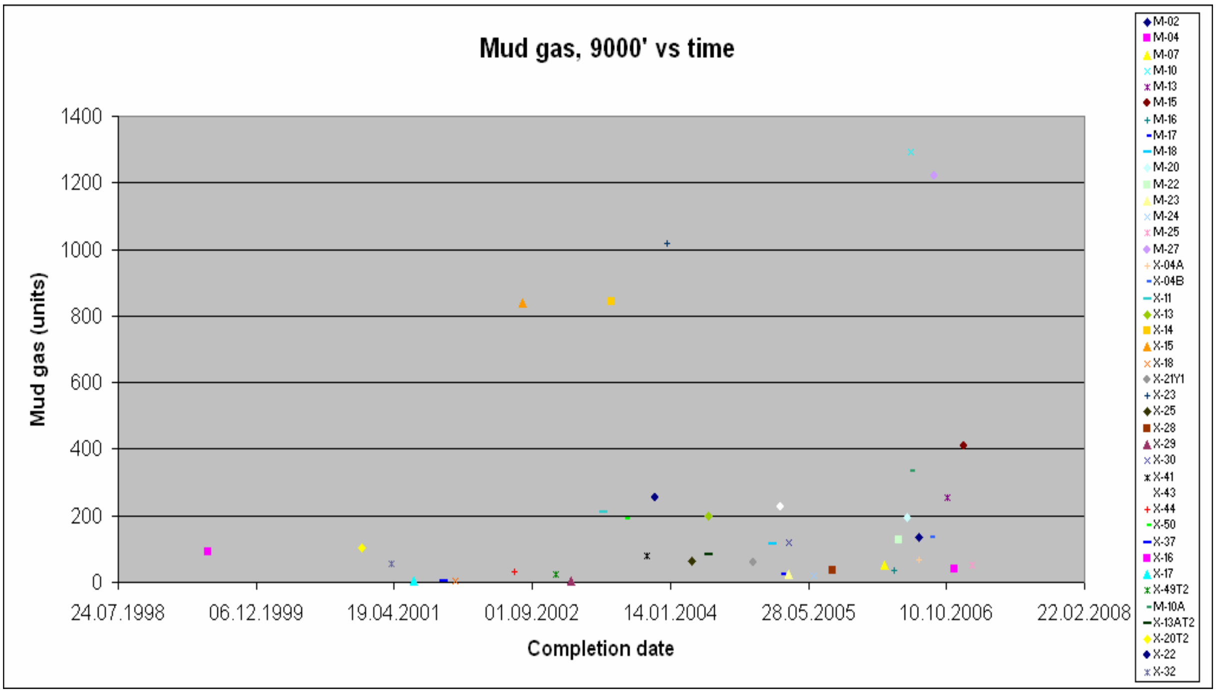
A slight increase of gas values in the overburden for all the different depth-intervals over time is observed. The increasing trend is most visible at the lowest depths; at 3300, 4000 and 5000 ft. The wells drilled before and in 2004 shows sporadic peaks, while most of the wells drilled in the latest part of 2000 shows generally higher gas values.

The 17-1/2" section is normally drilled down to approximately 4000 ft TVD, and before this depth is reached, the gas starts to enter the well. Graph 03 shows how the gas starts to enter the well at 3300 ft. The first recorded and stored gas value is done in 2001 and the value is approximately 40-45 units. Further investigation of graph 03 shows an increasing volume of gas in the overburden at 3300 ft, as the other lower depths. This corresponds with the experiences of the drilling crew offshore. The drilling crew offshore claims that there are both more gas and they "hit" the gas in the overburden at shallower depth than earlier. From these analyses with based on the graphs made, it looks like the drilling crew is right. Graph 03 shows the development of gas at 3300 ft. Due to the diffusivity it is difficult to see the trend. If we exclude the "worst" wells (the wells which have very high gas readings compared to the other wells at this depth) the graph 03 shows an increasing trend of gas values from 2001 to 2004. Many of the wells have actually 0 units or close to 0 units in gas values, but the overall trend is an increasing volume of gas with the highest peak in 2006.



Graph 06. Mud gas, 7500 ft vs. Completion date

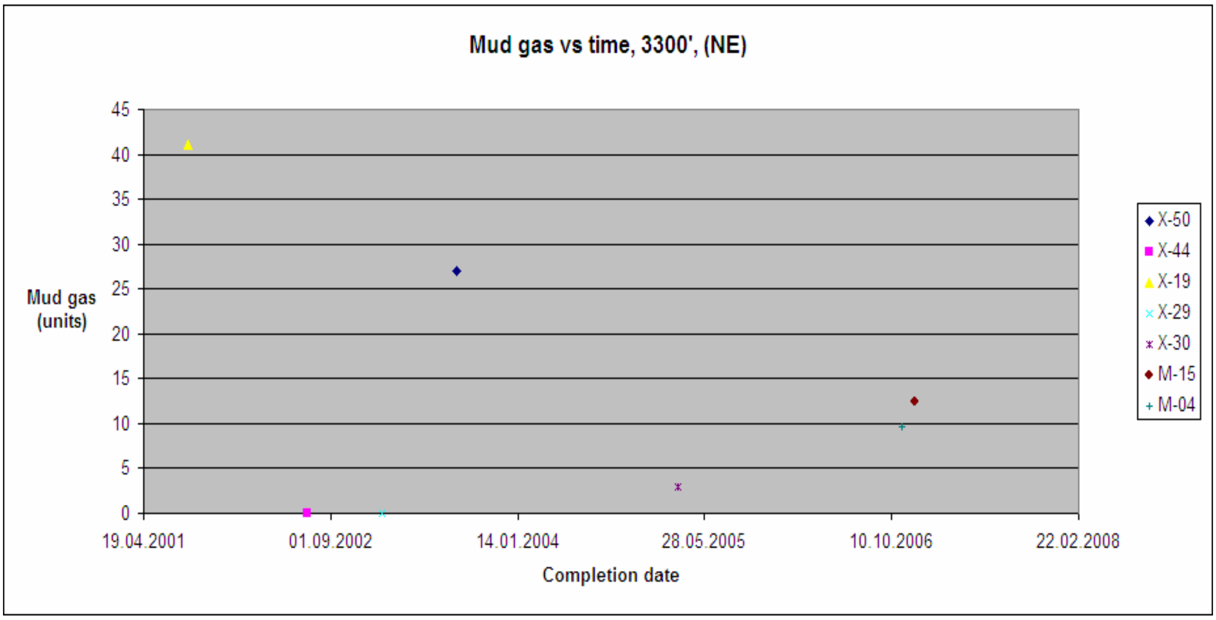
The 12-1/4" section is normally drilled down to approximately 10000 ft TVD. The production casing is set just above the reservoir section. Graph 06 shows how the gas starts to enter the wells at 7500 ft. The first reading at this depth was back in 1999, and the gas value is approximately 200 units. This trend is almost stable/constant with some smaller values to late in 2002. From late 2003, it seems like the gas is more aggressive with 2 higher peaks early in 2004 and late in 2006. There are also many wells with almost 0 units in gas values as well, but there is a general increasing trend of the gas at this depth.



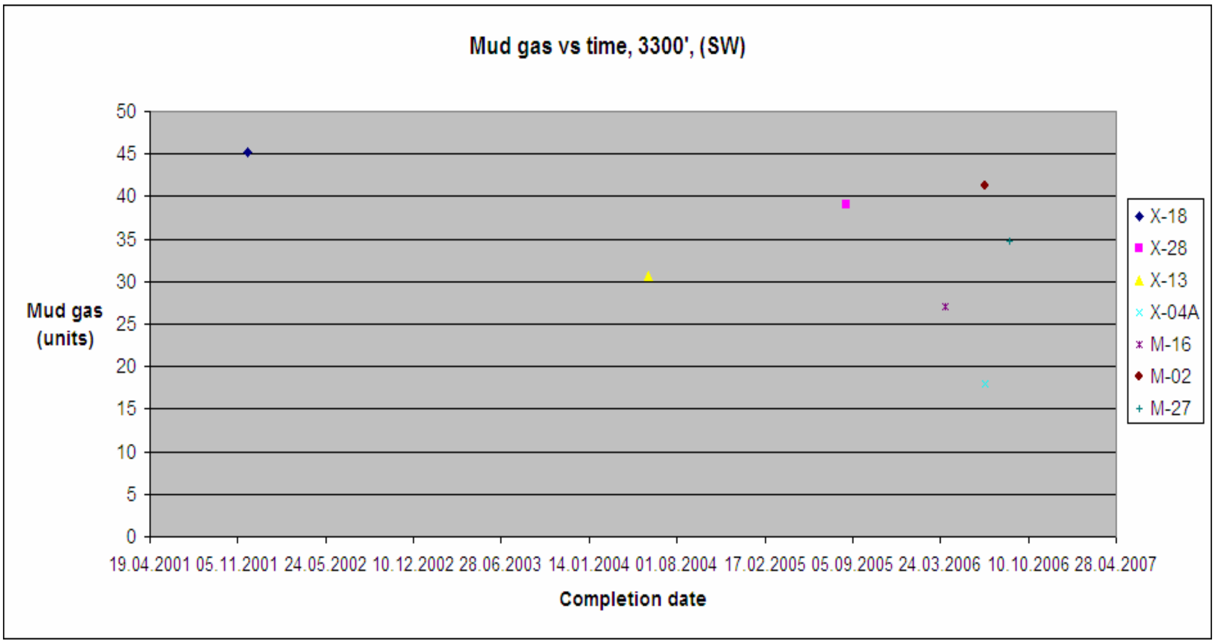
Graph 07. Mud gas, 9000 ft vs. Completion date

Graph 07 shows how the gas starts to enter the wells at 9000 ft. As the other graphs, there is an increasing trend in the gas values at this depth as well. The gas values are very low up to late 2002. Overall, there is an increasing trend with peaks as high as 1000 units in 2004.

It could be interesting to investigate if there are any regional differences with respect to gas in overburden over time for the most and least gas bearing zones. This can be done by comparing the graphs of the gas at different depths for the most gas bearing zone and the least gas bearing zone over time.

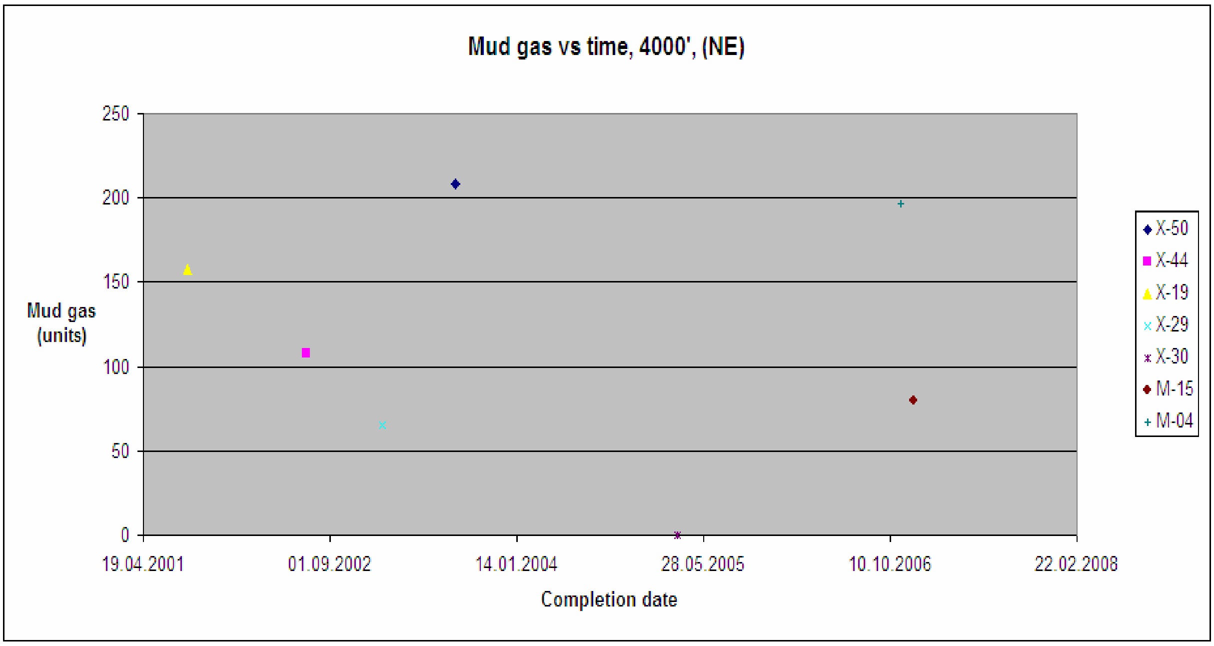


Graph 08. Mud gas, 3300 ft vs. time

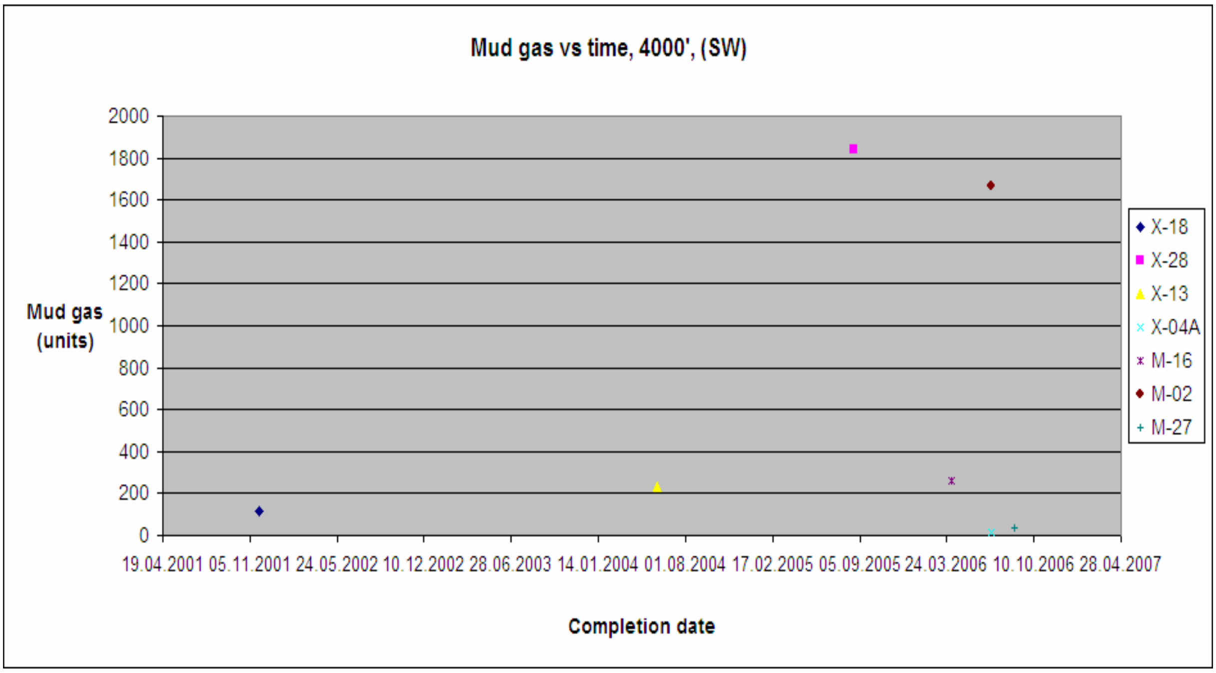


Graph 09. Mud gas, 3300 ft vs. time

The development of gas at 3300 ft does not indicate more gas these days compared to the previous drilled wells. The first well drilled at this depth with recorded gas was back in 2001. The gas readings were high for both areas. For NE area it seems like the gas development has decreased over the last 5 year, but for SW area it looks like the development is almost constant. The fact I discussed earlier in this thesis, that there is most gas in the SW area and least gas in the NE area is proven in graph 08 and graph 09. The average gas value is generally higher in the SW area.

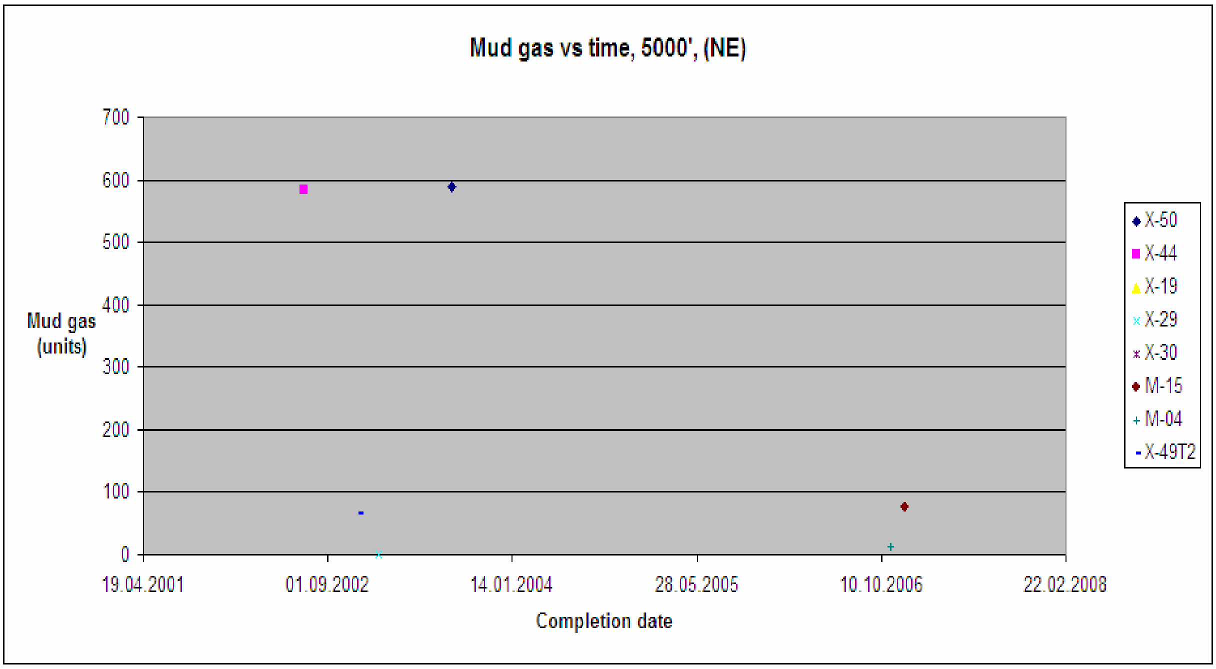


Graph 10. Mud gas, 4000 ft vs. time

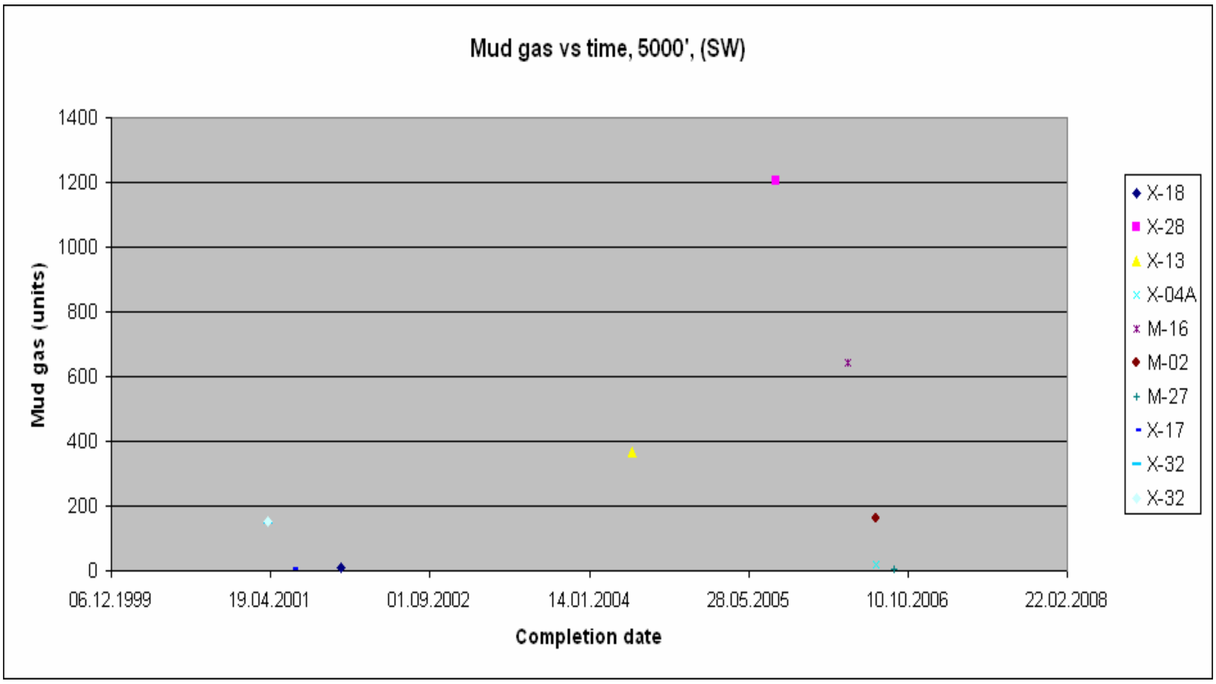


Graph 11. Mud gas, 4000 ft vs. time

The development of gas at 4000 ft does not indicate more gas these days compared to the previously drilled wells. The graph of the NE area shows almost a constant gas value at approximately 150 units. For the SW area, there are two wells which stand out from the average gas value of 150 units. X-28 and M-02 have very high gas readings compared to the other wells at this depth. It is no indication of increasing gas development over time at this depth for these two zones with exception of wells X-28 and M-02. If these wells are taken into account it seems like there is an increasing trend of gas in the SW area.

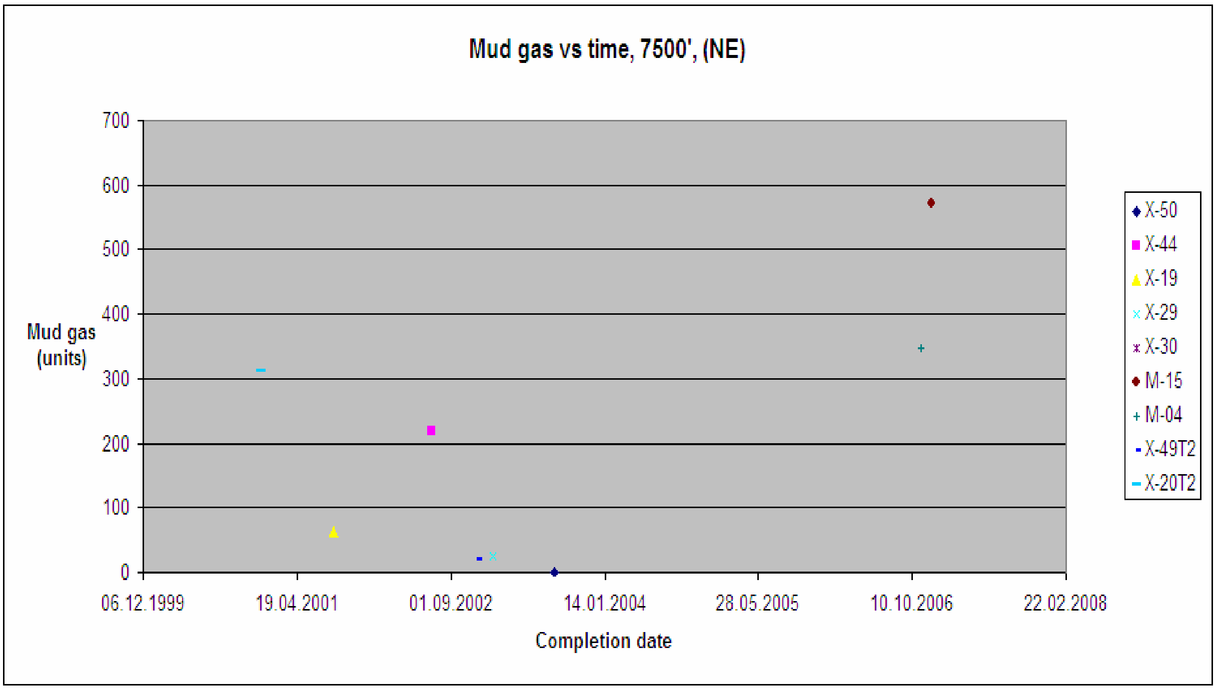


Graph 12. Mud gas, 5000 ft vs. time

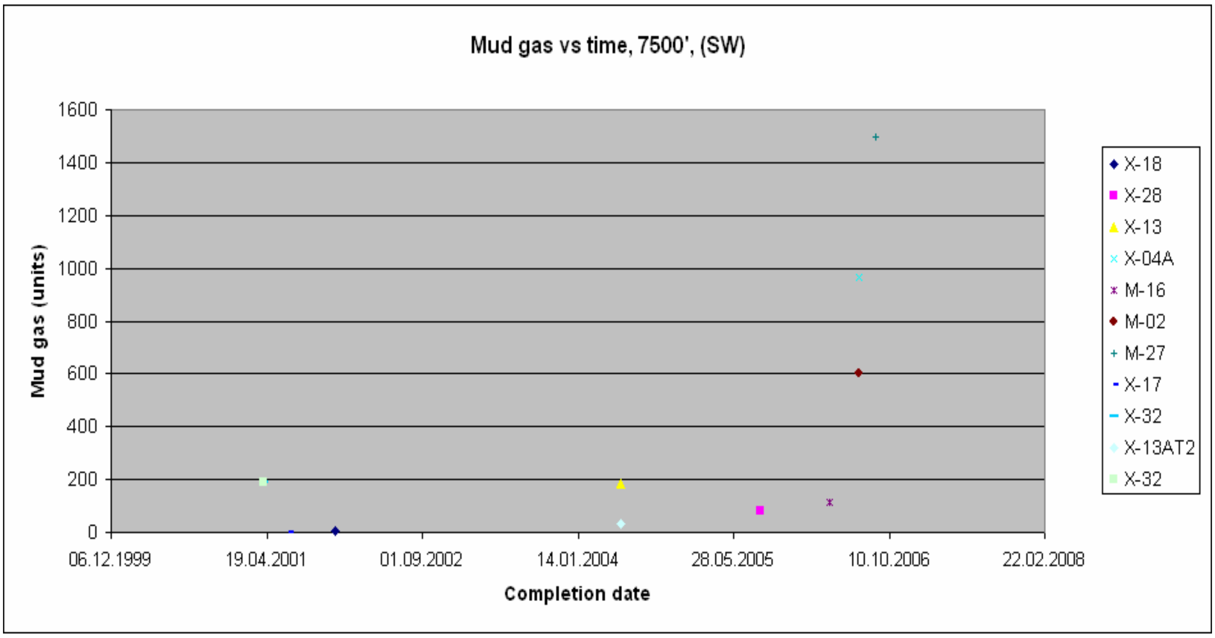


Graph 13. Mud gas, 5000 ft vs. time

The development of gas in the overburden varies for these two areas at 5000 ft. The SW area shows an increasing trend in the development of gas, while it is opposite for the NE area. The first recorded gas values for this depth is done back in 2002. For the SW area, the value is very low, approximately 0-100 units. From 2005-2006, there is an increasing trend of gas in the overburden with gas values from 0 to the highest peak at 1200 units. In graph 12, the NE area shows almost a decreasing trend. This can be a coincident, but the gas values are lower in 2006 compared to 2001.

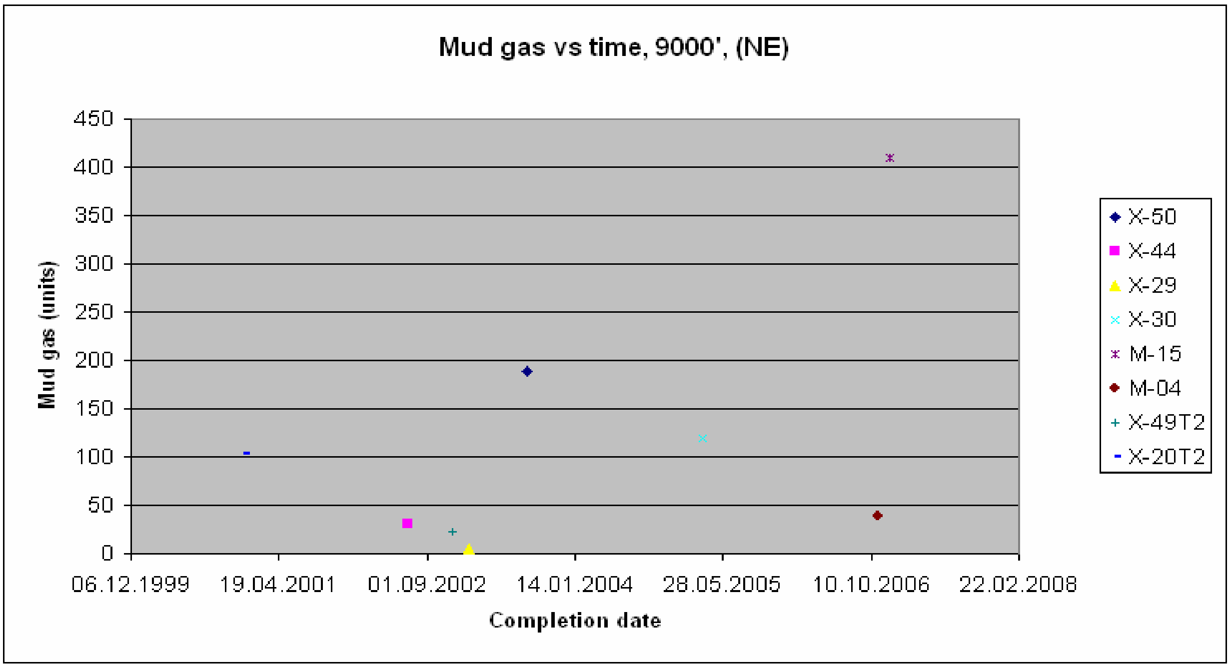


Graph 14. Mud gas, 7500 ft vs. time

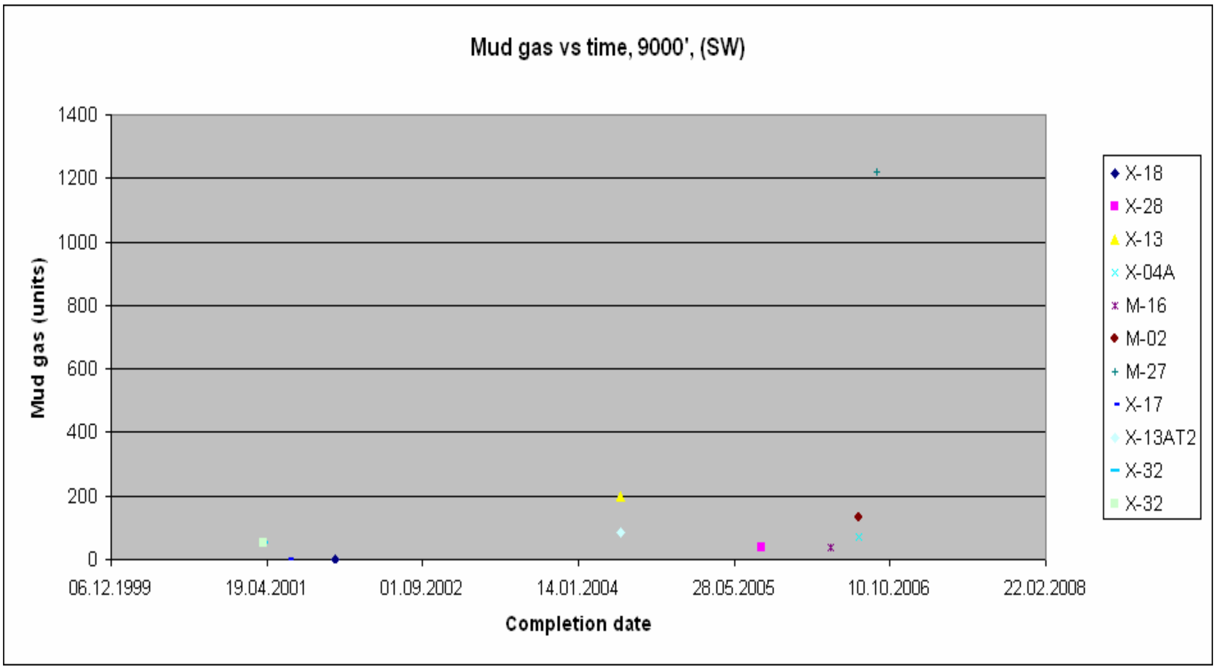


Graph 15. Mud gas, 7500 ft vs. time

The development of gas at 7500 ft indicates more gas these days compared to the previous drilled wells. It is most visual for graph 15, SW area. There are very small amounts of gas in the period 2001-2005, but there is an increasing trend of gas in the overburden for the wells drilled in 2006. In graph 14, the NE area also shows higher gas readings in 2006 compared to early 2000. This trend is not as visual as for graph 15, SW area.



Graph 16. Mud gas, 9000 ft vs. time

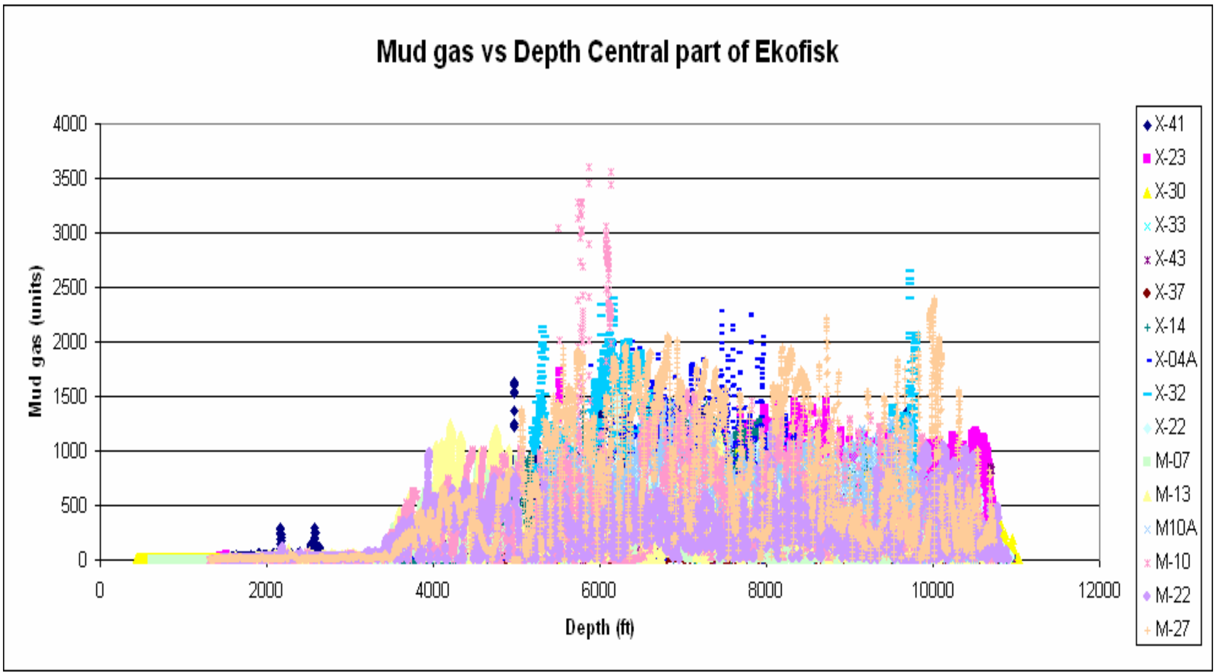


Graph 17. Mud gas, 9000 ft vs. time

The development of gas at 9000 ft do not indicate more gas at present time compared to previous drilled wells. If the well M-27 for the SW area is excluded, the gas values through the time scale shows almost a constant value.

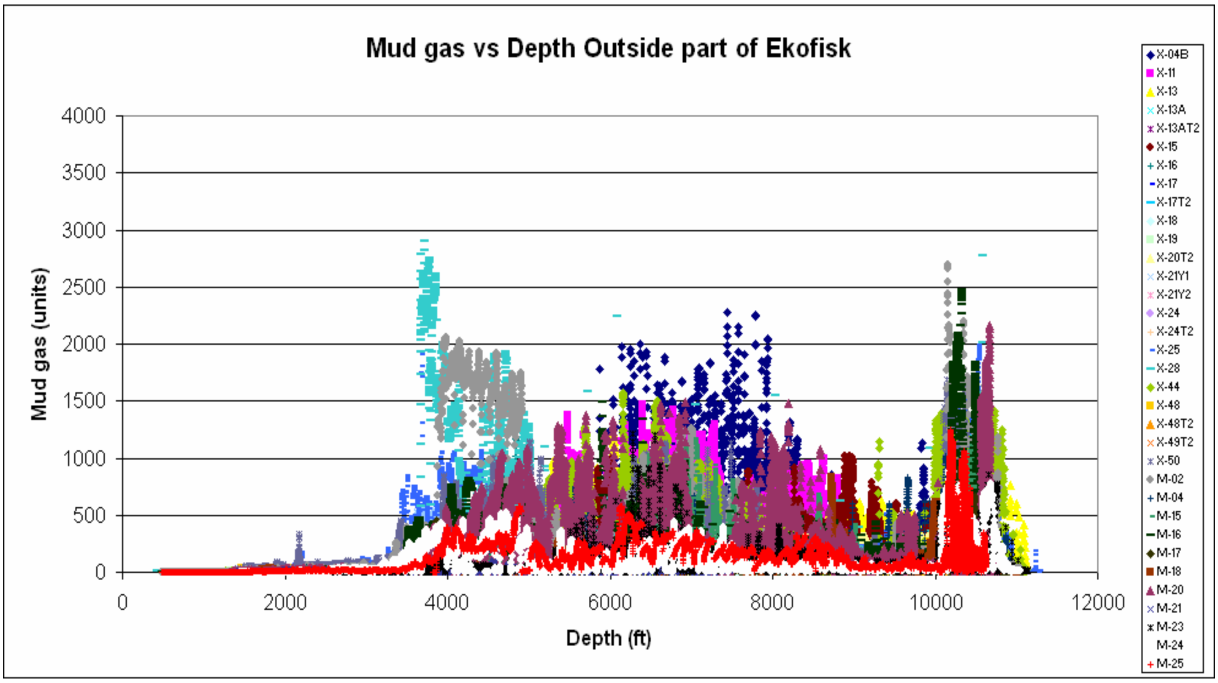
3.3. REGIONAL DIFFERENCES

The presence of gas in the overburden, above the crest of the field, is a well known feature. The gas cloud is less extensive above approximately 7000 ft TVD and markedly above 5000 ft TVD. The gas seems to increase with depth, peaking at approximately 5000 and 6000 ft. From 6000-10000 ft the graph stabilizes and decreases. At 3500 ft, the first instances of gas are recorded. This is in accordance with experiences from drilling operations for the newest wells. This detected gas depth agrees for both the central and outside part of Ekofisk, as seen in graph 18 and graph 19 below.



Graph 18. Mud gas vs. Depth, Central Part of Ekofisk

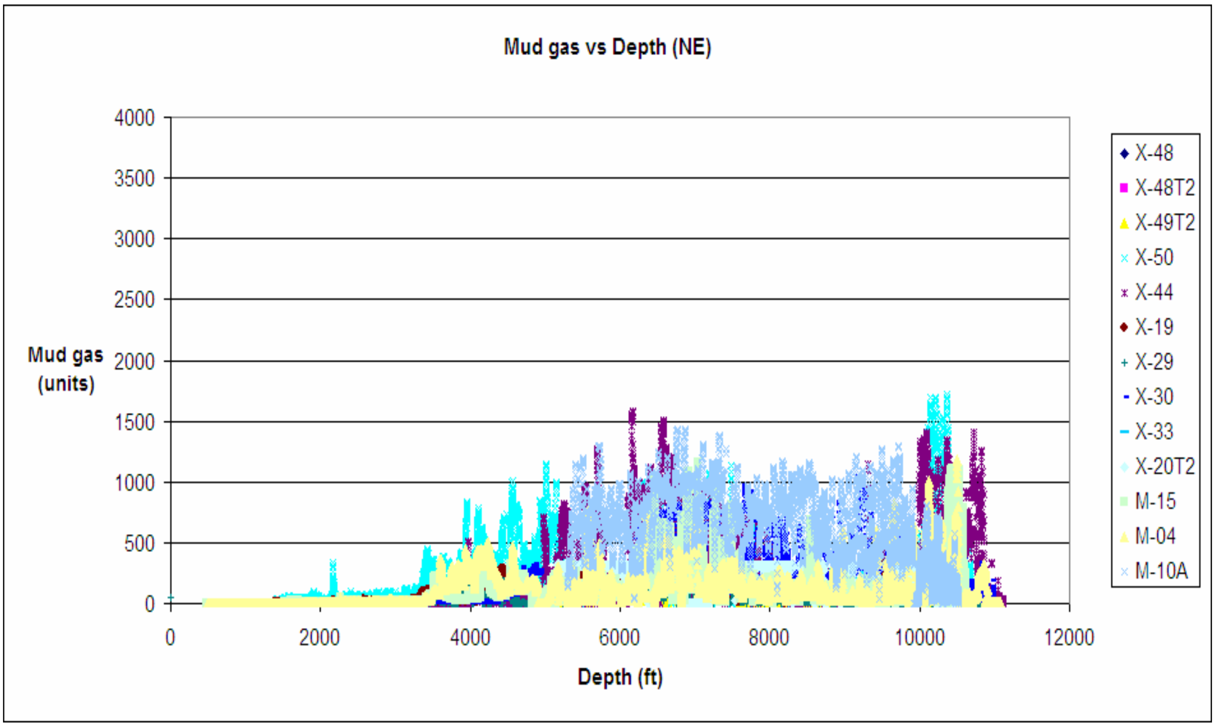
With comparison to the presence of gas in the overburden on the outside part of the Ekofisk field, we can see that there is markedly more gas in the central part. The average gas in the central part is approximately 1500 units, and for the outer part of Ekofisk, the average gas is approximately 1200 units, if wells 2/4-X-28, 2/4-M-02 and 2/4-X-04B are excluded. These wells differ from the other wells. The gas readings for these wells are higher compared to the rest of the wells drilled in the same zone. The reason for these higher gas readings can be due to the fact that these wells are all from newer date, drilled in the period from August 2005 to August 2006. Besides, these wells lie at the western part of the field, which seems to be the most gas bearing zone. This will be described later in this section, and can be the reason for the “strange” peaks at the graph below.



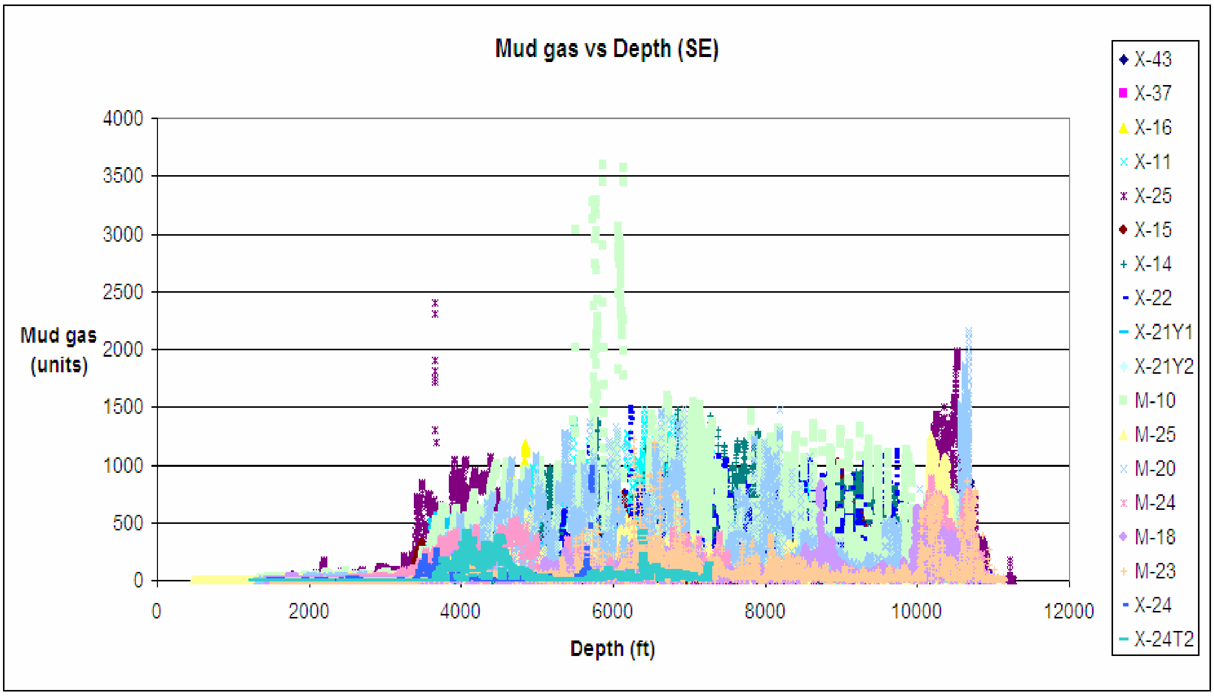
Graph 19. Mud gas vs. Depth, Outer part of Ekofisk

As written in the start of the thesis, the main purpose for this project is to determine if there is more aggressive gas in the overburden at present time compared to the previously drilled wells. For this investigation, the gas values needs to be plotted against completion date to see the development of the gas in the overburden. To visualize the development of the gas in the overburden, I have decided to plot the gas in depth-intervals like 3300, 4000, 5000, 7500 and 9000 ft vs. completion date.

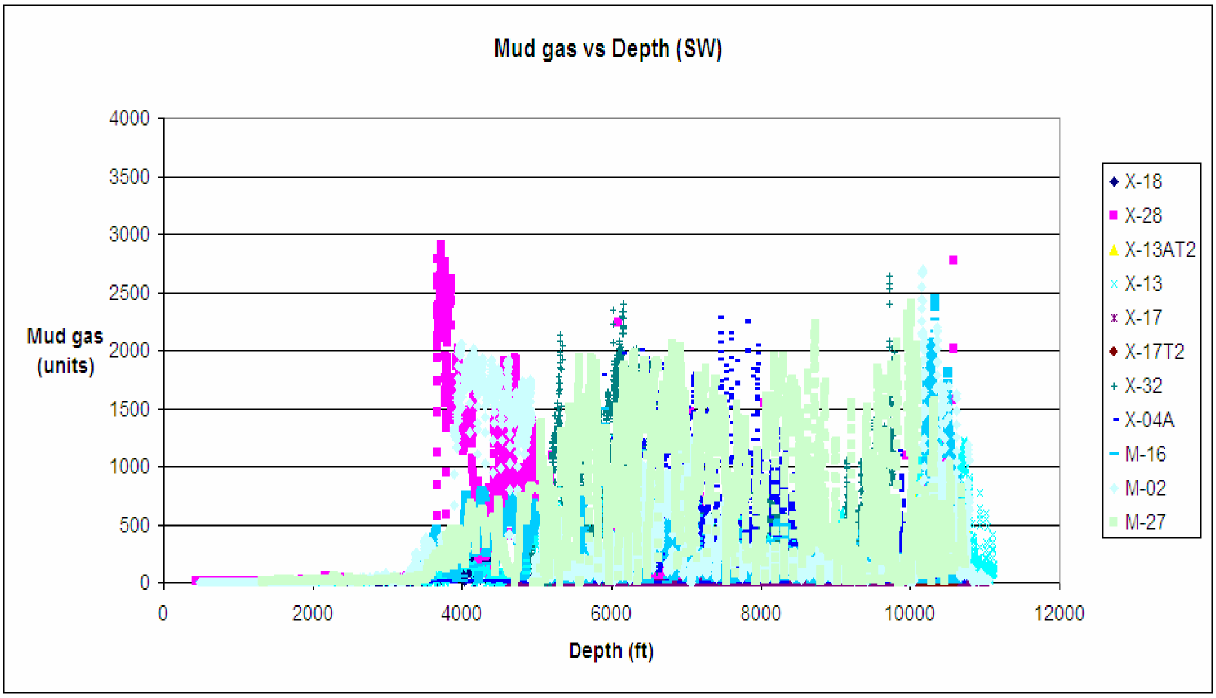
In the start of this section, I showed that there is more gas in the overburden in the central part of the Ekofisk field compared to the outside part. I also checked for other regional differences.



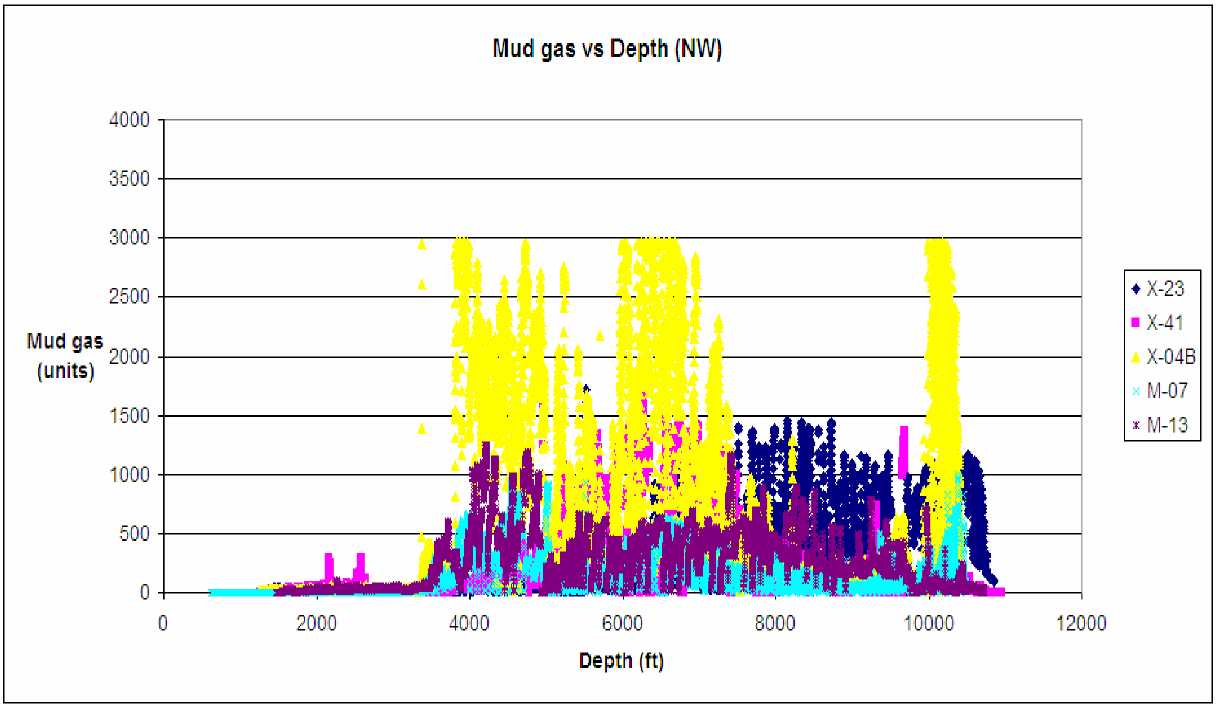
Graph 20. Mud gas vs. Depth for NE



Graph 21. Mud gas vs. Depth for SE



Graph 22. Mud gas vs. Depth for SW



Graph 23. Mud gas vs. Depth for NW

The Ekofisk field was divided into 4 sectors for the investigation of potential regional differences. The field was divided into North-East (NE), South-West (SW), North-West (NW) and South-East (SE). Graph 20 and graph 22 are the two graphs which differ from the two other graphs. In graph 20, NE area is the area with lowest content of gas. The gas is first detected at approximately 3500 ft for this well as for the other wells. The highest value of gas is at approximately 6000 ft where it reaches a value of 1600 units. The whole zone has an average gas value of approximately 1000-1100 units.

In graph 22, SW area is the area with definitely highest content of gas. The gas readings are generally higher in the whole depth range. The gas is first detected at 3500 ft, and end at 11000 ft. The whole area has an average mud gas value of approximately 1800 units.

The two other graphs shows gas readings which lie between the two graphs described above. They show an average gas value of approximately 1500 units. The SW sector is the most gas bearing sector and the NE sector as the least gas bearing sector.

Cuttings injection increases the pore pressure and reduces the effective horizontal stress if we assume constant matrix stress. The reduction of the effective stress can cause more fractures and make the gas more mobile. During this section, I will investigate if the cuttings re-injection wells are influencing the development of gas in the overburden.
The X-38 (1996), X-24 (2004) and M-21 (2006), are located in the NE, SE and SW sector, respectively. Previously in my analysis, I have seen regional differentiations. The NE sector is the least gas bearing sector and the SW sector is the most gas bearing sector. How do the localizations of these injection wells influence the development of gas in the overburden?
Since the X-38 well started the cuttings injection in 1996, I assume the NE sector has been exposed to a higher volume of cuttings and a corresponding pressure increase in the formation in overburden. I would believe that the NE sector to be the most gas bearing sector due to the changes in the fractures and channels in the overburden during cuttings injection. But this is not the case, it is rather opposite.
The newest cuttings injection well is located in the SW sector, the most gas bearing sector. Based on the assumptions of less volume of cuttings injection for the newest well, I would believe that the SW sector to be the least gas bearing sector, which is not the case.
Based on this analysis, I can not see the relation between cuttings injection in the different sectors and the problem to be addressed; development of gas in the overburden.

The water injection well 2/4-K-22 is located in the northern part of the Ekofisk field. The platform is located in the NW sector, but the well path is directed to the eastern sector. On 7th of May 2001, a seismic event occurred in the north part of the Ekofisk field. The investigation done after this event showed that some wells had developed casing deformation and that 2/4-K-22 was injecting 15000 bbl/day of water into the overburden. The injection of the water in the overburden took place at a depth of 6000-7000 ft TVD. The water injected into the overburden increases the pore pressure and probably makes more fractures, where the gas can migrate. Since the collapsed water injection well is located in the northern part of the field, it would be likely to see a higher volume of gas in this area. This is not the case, so the event (2/4-K-22) does not impact the development of the gas in the northern part of the field?

4.DISCUSSION

In this section, I will discuss the potential causes of the increasing trend of more aggressive gas in the overburden at recent time compared to some years ago. To illustrate/visualize the causes, I have selected to generate the causes into five sections; 1) Depletion due to production, 2) Injection of gas, 3) Injection of cuttings, 4) The water-injector accident, and 5) Other causes. For sections 1), 3) and 4) the fundamental theory, figures and equations, I will report back to the chapter 2.2.2, 2.2.3 and 2.3.4.

1) The Ekofisk field is a naturally-fractured chalk reservoir in the Norwegian sector of the North Sea that has produced hydrocarbons for over 30 years. The in situ stresses in the field have been constantly changing because of the decline in pore pressure that has occurred in the reservoir as a result of the production. The initial reservoir pressure was 7135 psia and during the production the reservoir pressure has decreased to 5100 psia. This pressure reduction is not only a factor of reduced pore pressure due to production over 30 years. Water and gas injection, which has been done for the last 20 years, was implemented due to keep up the reservoir pressure. It was believed that water injection would prevent further decrease in the reservoir pressure. The discovery of subsidence in November 1984 was quite unexpected, and a result of this subsidence implementation of water injection was established. As written in the theory section about the water injection, recently studies at the University of Stavanger has showed that chalk injected with water results in a reaction called dolomitization. This reaction is called the water weakening effect. It is believed that this effect is a reason for the increased compaction of the reservoir. This compaction is more than what the overburden can take with respect of loads and stresses. The reservoir compaction is stretching the overburden, which induces a change in the horizontal effective stresses in the overburden, if assuming a constant overburden load. These changes in the effective horizontal stress field may induce increasing and changes of cracks and channels in the formation in the overburden, where the gas may migrate through.

2) Injection of gas was first implemented due to avoid further depletion of the reservoir pressure. This gas injection was a success in attempting to mitigate further depletion in the reservoir, but the gas injection could not mitigate subsidence. Several independent efforts to obtain information related to gas migration and gas distribution have been performed as part

of the gas injection evaluation. Most of the efforts involved evaluation of historical field data. They include time lapse well GOR field mapping, evaluation of a gas tracer project, estimation of gas saturation profiles from pulsed neutron porosity logs, determination of well GOR profiles from production logs, review of historical RFT pressure data and compositional analysis of the produced stream. (See section 2.3.3). The most interesting evaluation for this thesis is to study whether there is a link between the injected gas and the observed gas in the overburden. The compositional analysis of the produced stream would probably be the best way to see the link between the produced gas and the injected gas. The conclusion of the evaluation, the weak correlation of GOR in some wells and the fact that five wells started to produce injected gas before the bubble point was reached, indicate that gas channeling is a factor at Ekofisk. Is it this injected gas which is observed in the overburden during the drilling operations?

3) In response to increasing concerns over the environmental effects of the disposal of drilling cuttings to the sea, COPNO began to dispose cuttings through injection into underground strata late in 1996. These cuttings injectors, X-38 (1996), X-24 (2004) and M-21 (2006) are located in NE, SE and SW sector respectively. The injection of the cutting in the formation in the overburden increases the pore pressure. If assuming constant matrix stress get a corresponding reduction of the effective horizontal stress. These changes in the effective horizontal stress field may induce increasing and changes of fractures and channels in the formation in the overburden, where the gas may migrate through. From my analysis, I would believe that an area with a cuttings injector would show a higher content of gas compared to an area without such an injector. This is not the case in this evaluation. Since the NW area is the only area which is not injected with gas, I would believe that this area would be the least gas bearing area. From my analysis it seems like the NE area is the least gas bearing area even though this area have a cuttings injector. The link between cuttings injectors and observed gas in the overburden is not universal. The reason why there is not a correlation between the injection of cuttings and the gas can be the development of the field itself over the production time, or rather study the amount of injected cuttings. The amount of cuttings injected is so small compared to the total volume of the overburden.

4) Water injection was initiated due to subsidence and the water is injected into the reservoir to maintain the reservoir pressure. On 7th of May 2001, a seismic event of moderate size

occurred in the southern North Sea. Since this event was so strong, it might be expected that it would cause well failures. In 2002, while drilling from the 2/4-B platform (see figure 14 in section 2.3.4) in the northern flank of the field, abnormally high pressures were observed in the overburden at 6000-7000 ft TVD. This led to an investigation in that area. It was found that some of the wells had developed casing deformations, and closer investigation confirmed that due to a previous overburden collapse one water injector (2/4-K-22, figure 14) was injecting 15000 barrels/day of cold water into the overburden. This injected water is increasing the pore pressure and with the assumption of constant overburden load, get a reduction of the effective horizontal stress. This stress change may cause changes in cracks and channels as discussed earlier in this section. 2/4-K-22 is located in the northern part of the Ekofisk field, more exactly in the NE area, and I would believe that this area would show higher contents of gas compared to the southern part. This is not the case. The southern part is the most gas bearing area, even if the leak occurred in the northern part. The NE area is the least gas bearing area. What is the relationship between these water-and cuttings injectors and observed gas in the overburden? Development over time?

5) Poor cementation jobs can be a reason for the observed gas in the overburden. The well is penetrating the reservoir. The liner/casing is then cemented as per procedure. If this cementation is poor, there is a great possibility that the gas can migrate upwards along the liner/casing. The subsidence of the field will “stretch” the overburden and also the cement outside the liner/casing. The possibility for gas channeling along the casing/cement is present.

The ROP, mud weight and under balanced drilling may influence the development of the gas in the overburden.

The ROP has a significant impact on the gas level and mud weight in the borehole. A high ROP brings more gas (drill gas and gas contained in microfractures around the wellbore) into the mud than a low one.

The density of the drilling mud qualifies the hydrostatic pressure in the well. If the hydrostatic pressure is less than the formation pressure, the operation is called under balanced drilling. When drilling with less pressure in the well compared to the formation pressure, the inflow rate from the formation into the well is greater compared to balanced or over balanced drilling. This inflow affects the amount of gas in the well.

5.CONCLUSION

Finally I will come up with some conclusions from my analysis. The conclusions are based upon the data available and the edited work.

The main task for this thesis was to investigate and study if there is more gas in the overburden at present time compared to earlier time. Based on my prepared graphs, it seems like there is more gas in the overburden at present time compared to earlier wells. The increasing trend of gas is visible at all my depth ranges, but it is most visible at the lowest depths as shown in graphs 03, 04 and 05 at 3300, 4000 and 5000 ft respectively. There is a perceptible increase of gas values in my prepared graphs from mid 2004. Before 2004, it seems to be more or less constant gas values, with expectation at a depth of 9000 ft, where you can see a markedly increase late 2002. After 2004,

The gas is first seen at 3300 ft. (See graphs 20-23). This is common for all the graphs at all the different depths and sectors. This is in line with COPNO's experiences. This depth is shallower compared to earlier wells.

It is a well know feature that there is a gas cloud above the crest of the field, and based on my analysis, it seems like there is substantial more gas in the overburden at the central part of the field compared to the outer part of the field. (See graphs 18-19).

I divided the Ekofisk field into four sectors; NE, SE, NW and SW. From my analysis, it seems like the SW sector is the most gas bearing sector and the NE sector is the least gas bearing sector. (See graphs 21-22). The two other sector, NW and SE, shows an average gas value which lies in between.

Based on my data, it does not seems like there is a clear relationship between the cuttings injectors, the 2/4-K-22 well, and the development of the gas in the overburden. By comparing the location of the wells and the evaluation of the graphs, can not see any connection which call for increased volume of gas in areas with injectors.

6.NOMENCLATURE

TERM	DESCRIPTION
API	American Petroleum Institute.
ΔA	Area
bbl	Barrels
Ca	Calcium
COPNO	ConocoPhillips
ft	Feet
F	Fahrenheit
ΔF	Force
ΔF_N	Normal Force
ΔF_S	Shear Force
GG	Geology and Geophysics
GOR	Gas Oil Ratio
I	Invariant
in^2	Square inch
K	Correlation factor
lb	Pound
mD	Milli Darcy
Mg	Magnesium
MSL	Mean Sea Level
NOK	Norwegian crones
NORSOK-D-010	Norwegian regulatory description
NE	North-East
NW	North-West
OW	OpenWork
P_h	Hydrostatic pressure
P_o	Pore pressure
p_c	Cement pressure
PV	Plastic Viscosity

RFT	Resistivity Formation Test
ROP	Rate of Penetration
SCF	Standard Cubic Feet
SE	South-East
SO_4	Aluminum sulfate
STB	Standard Barrels
SW	South-West
T	Stress tensor
TVD	True Vertical Depth
TVDSS	True Vertical Depth Sub Sea
WBE	Well Barrier Element
YP	Yield Point
z	Depth/height
α	Biot's constant
ρ_{mud}	Density of mud
γ_c	Density of cement
θ	Direction/angle
σ	Stress
τ	Shear stress
ϕ	Angle
σ_i, i = 1,2,3,r,θ, z, H, h, v	i = 1,2,3: Principal stress i = r: Radial stress i = θ: Tangential stress i = z: Axial stress i = H,h: Horizontal stress i = v: Vertical stress
τ_i, i = $\theta z, rz$	Shear stress
σ'	Effective stress
σ_a	Horizontal stress
ν	Poisson's ratio

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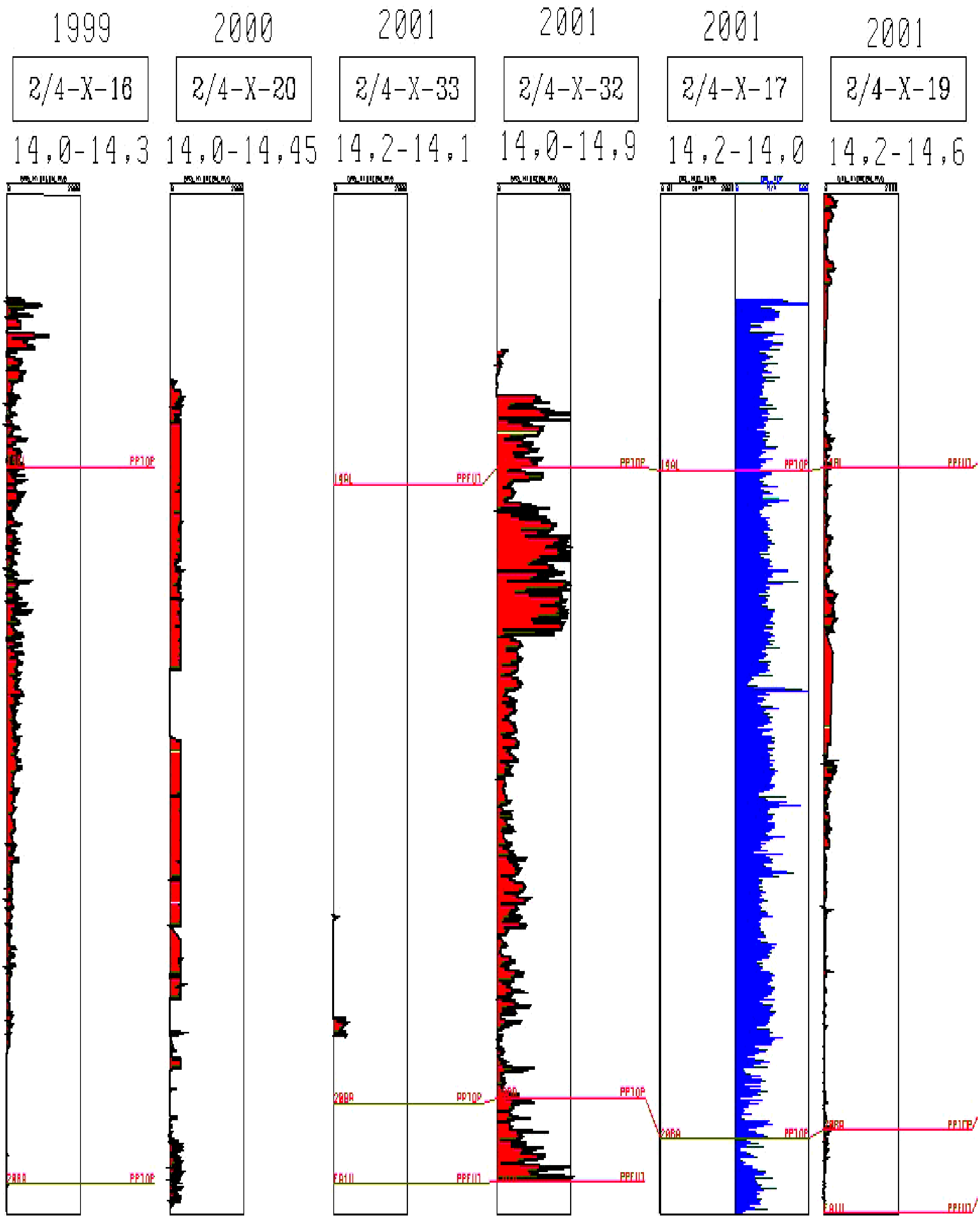
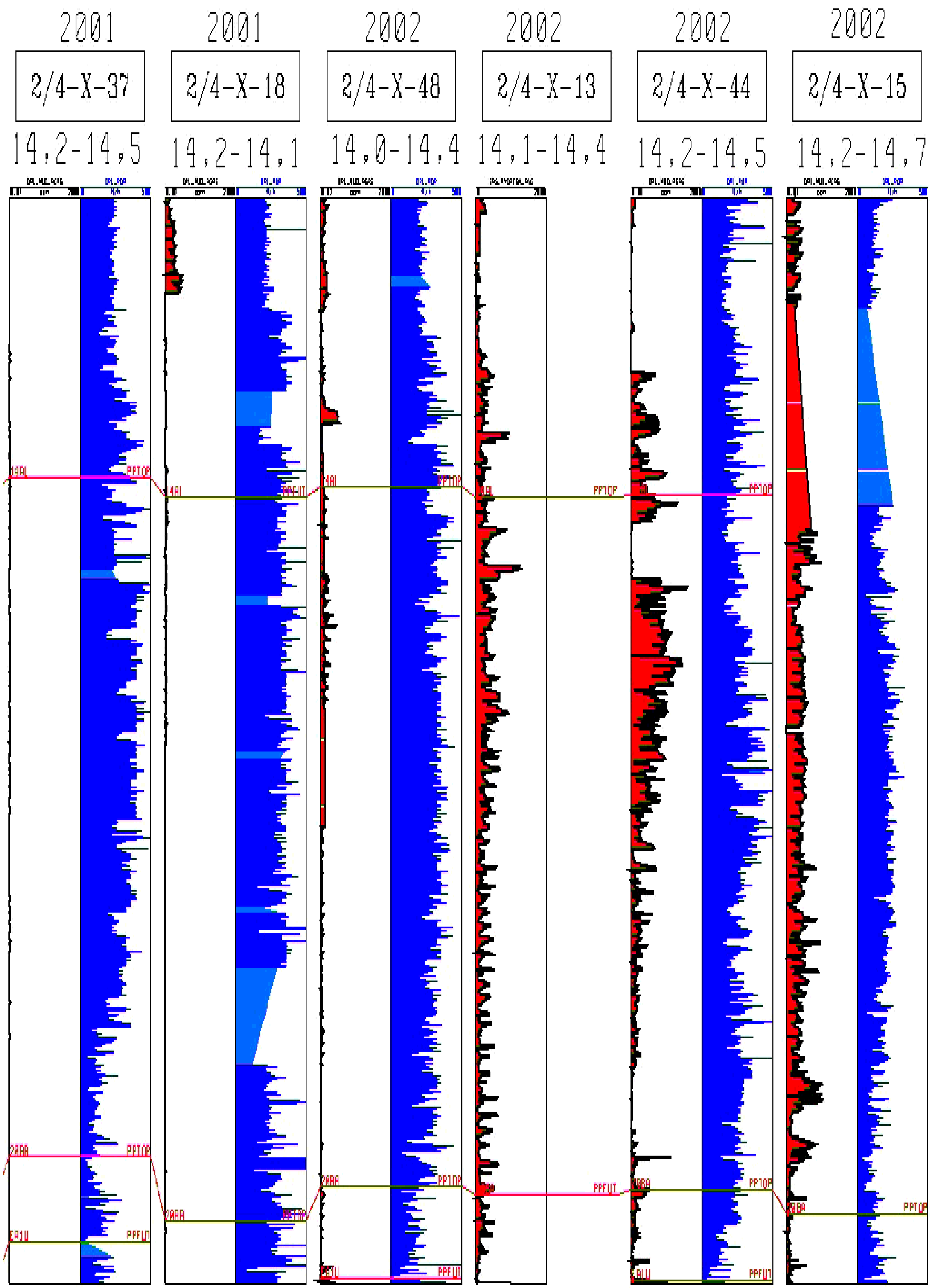
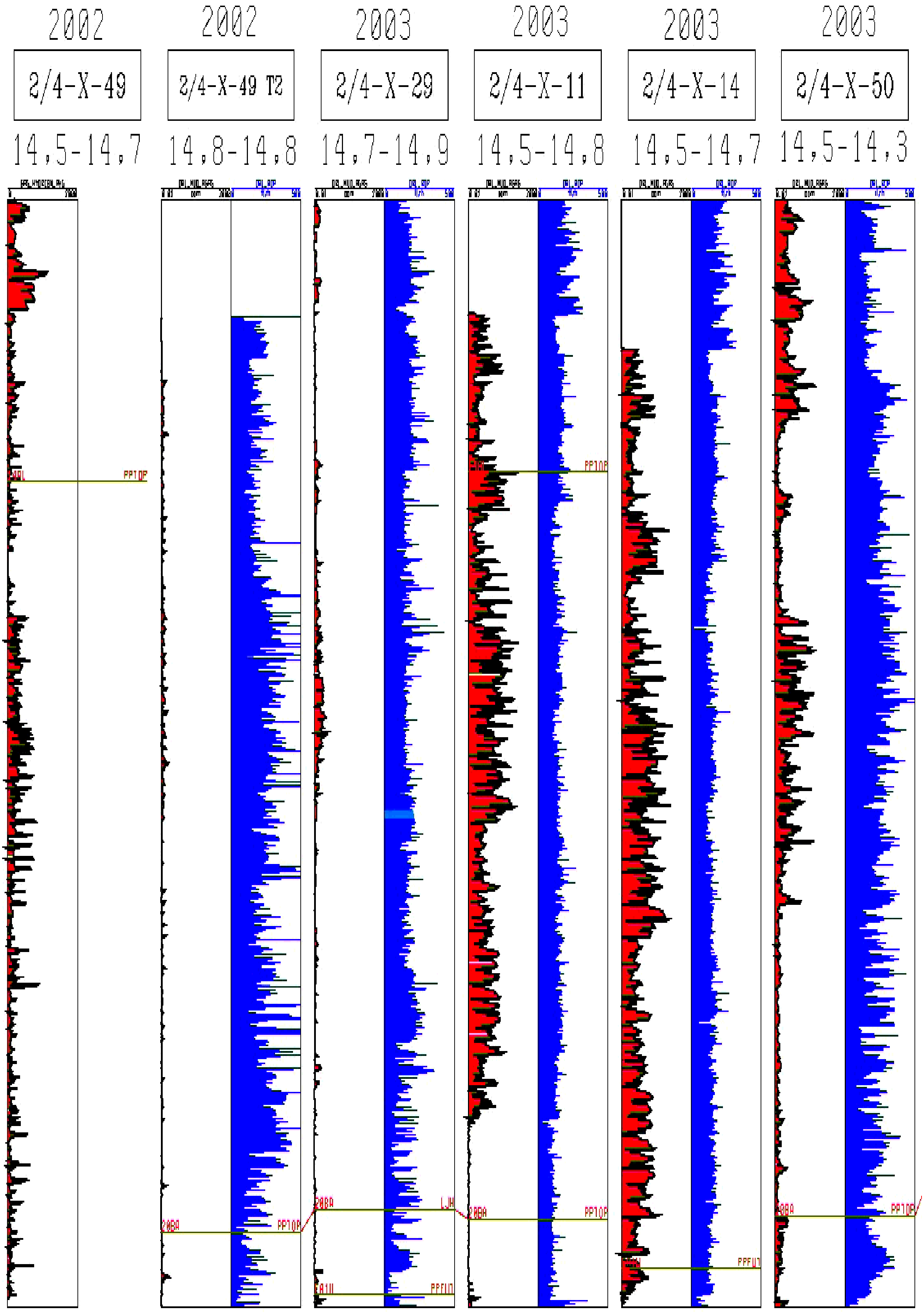
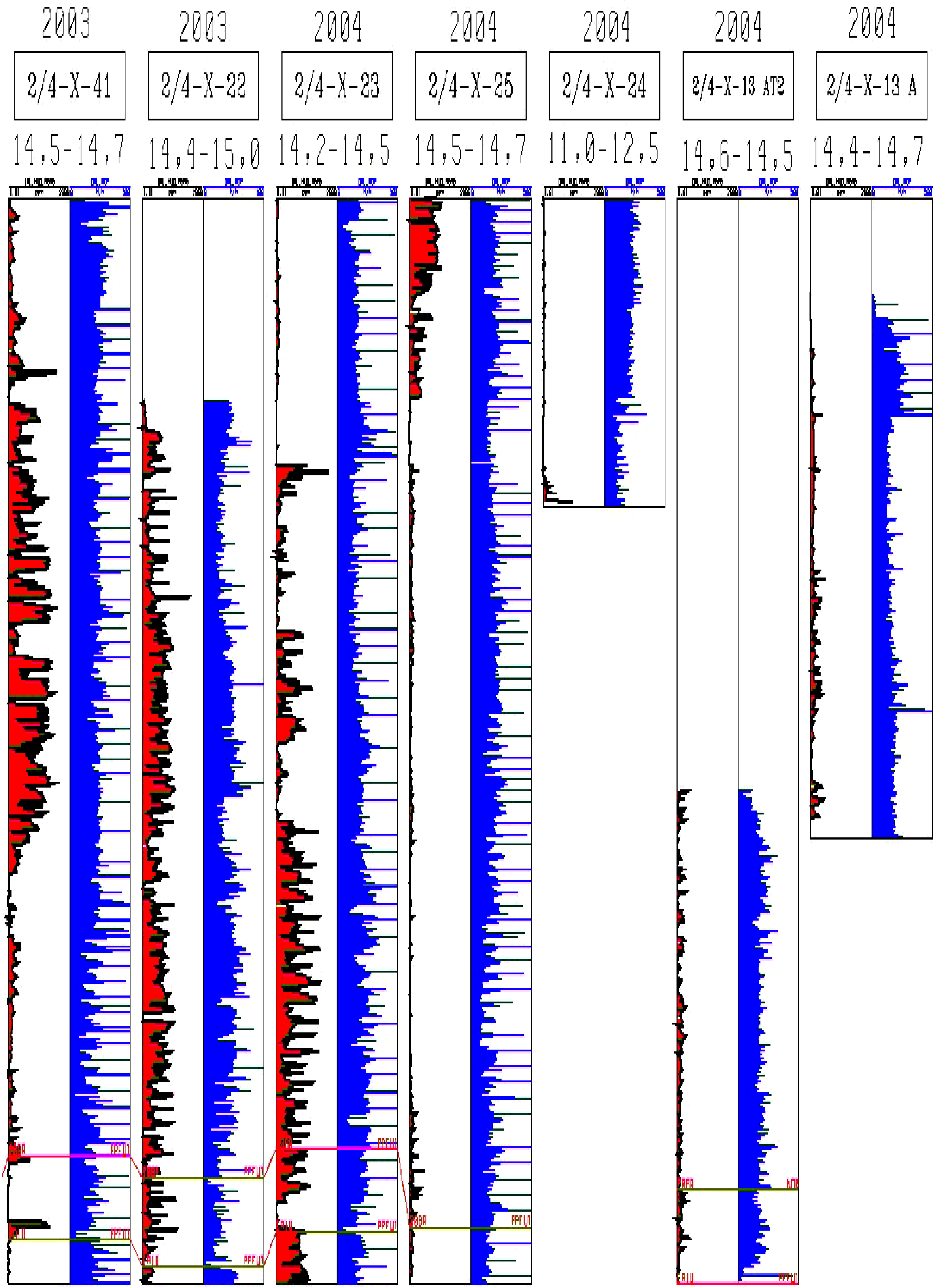
APPENDIX

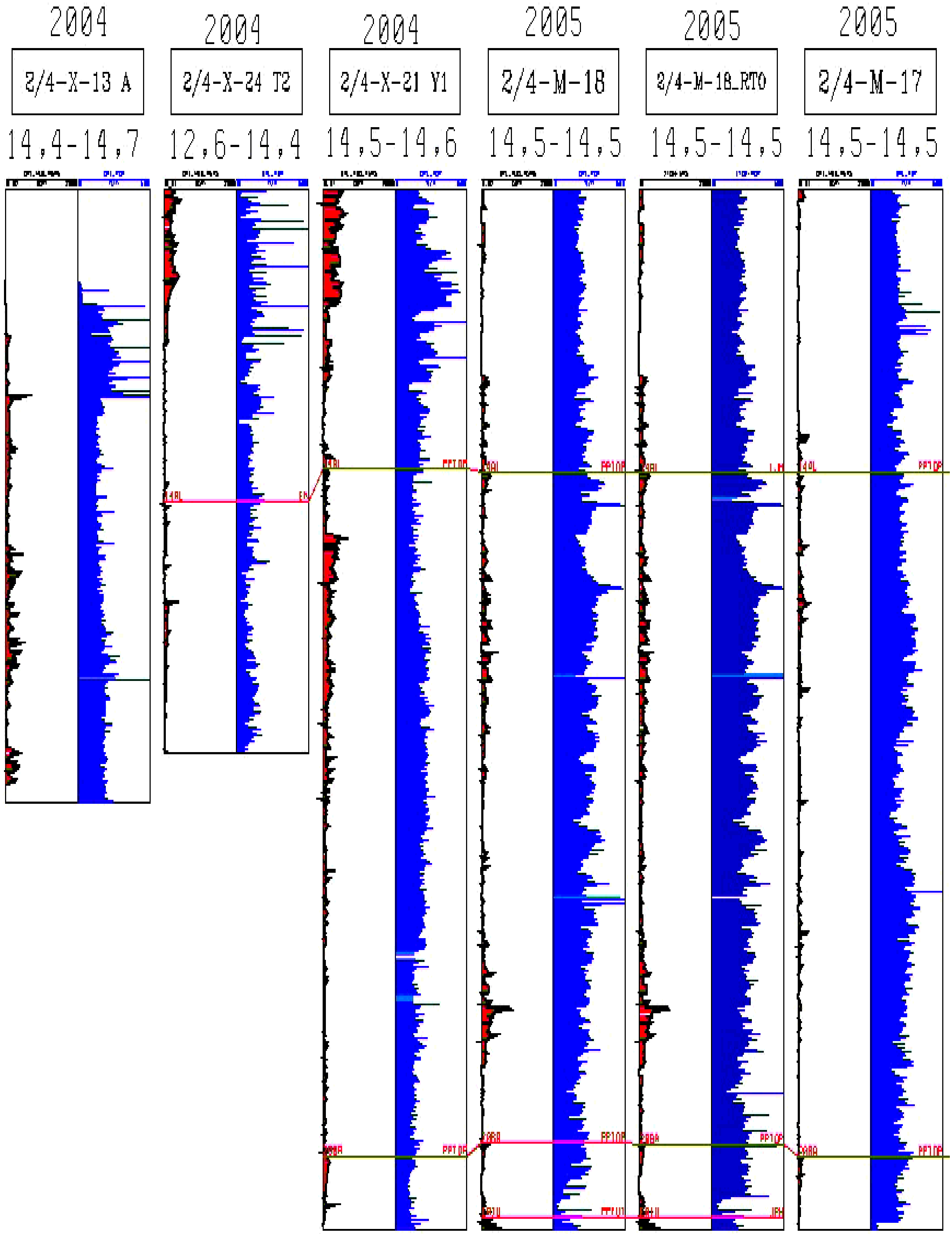
A. Mud gas logs from OpenWorks

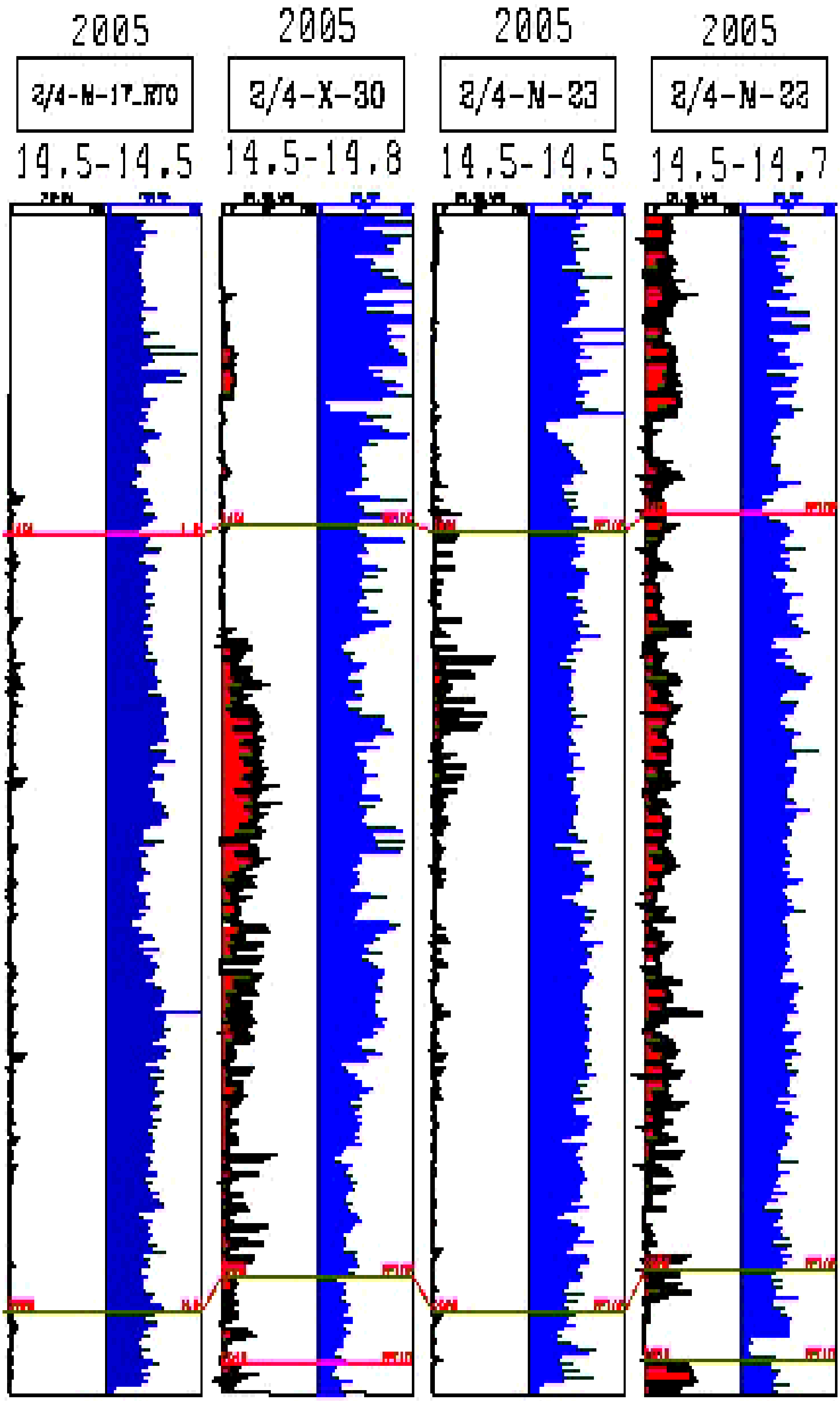


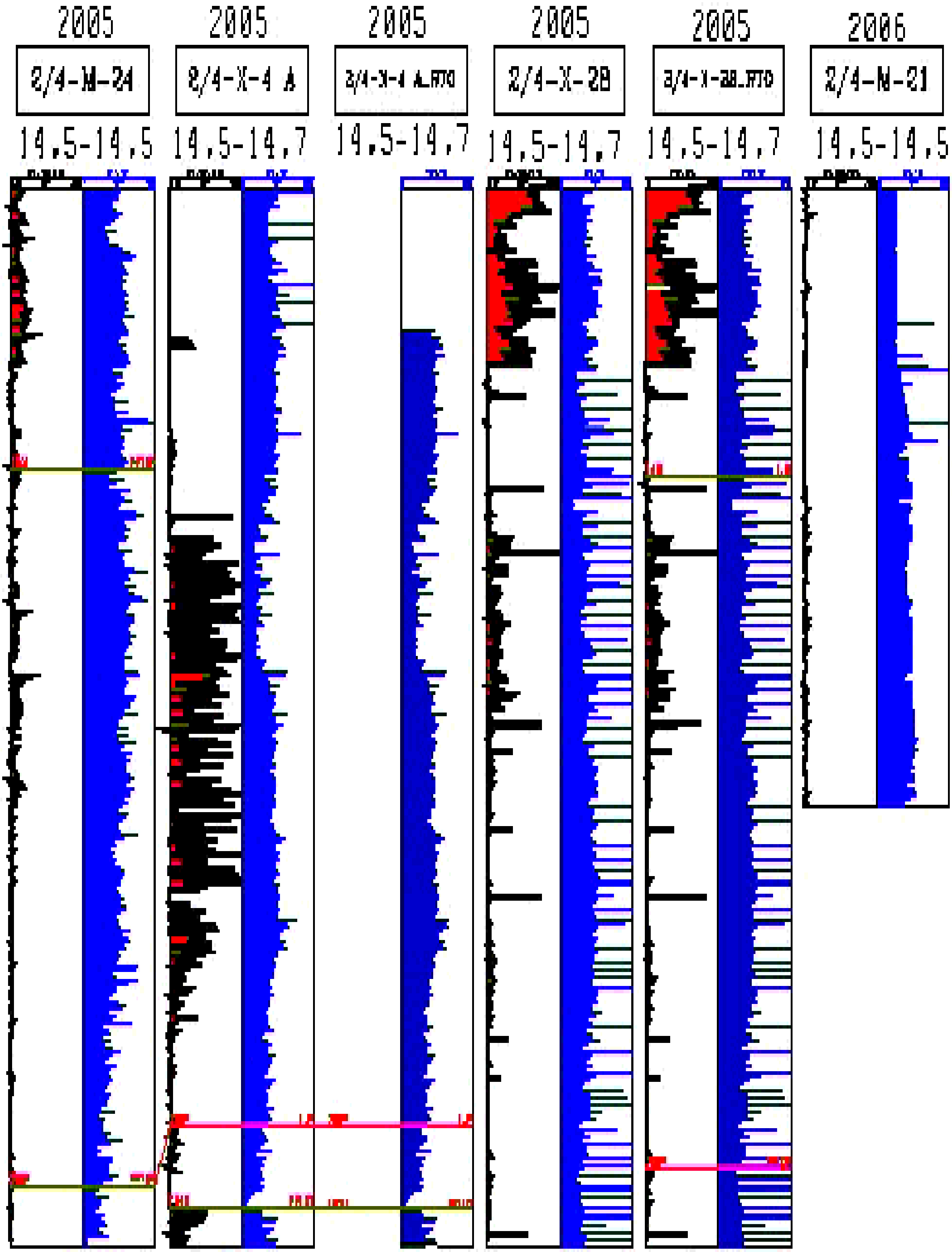

2001
2/4-X-37
14,2-14,5
2001
2/4-X-18
14,2-14,1
2002
2/4-X-48
14,0-14,4
2002
2/4-X-13
14,1-14,4
2002
2/4-X-44
14,2-14,5
2002
2/4-X-15
14,2-14,7
PPTOP
PPFUT

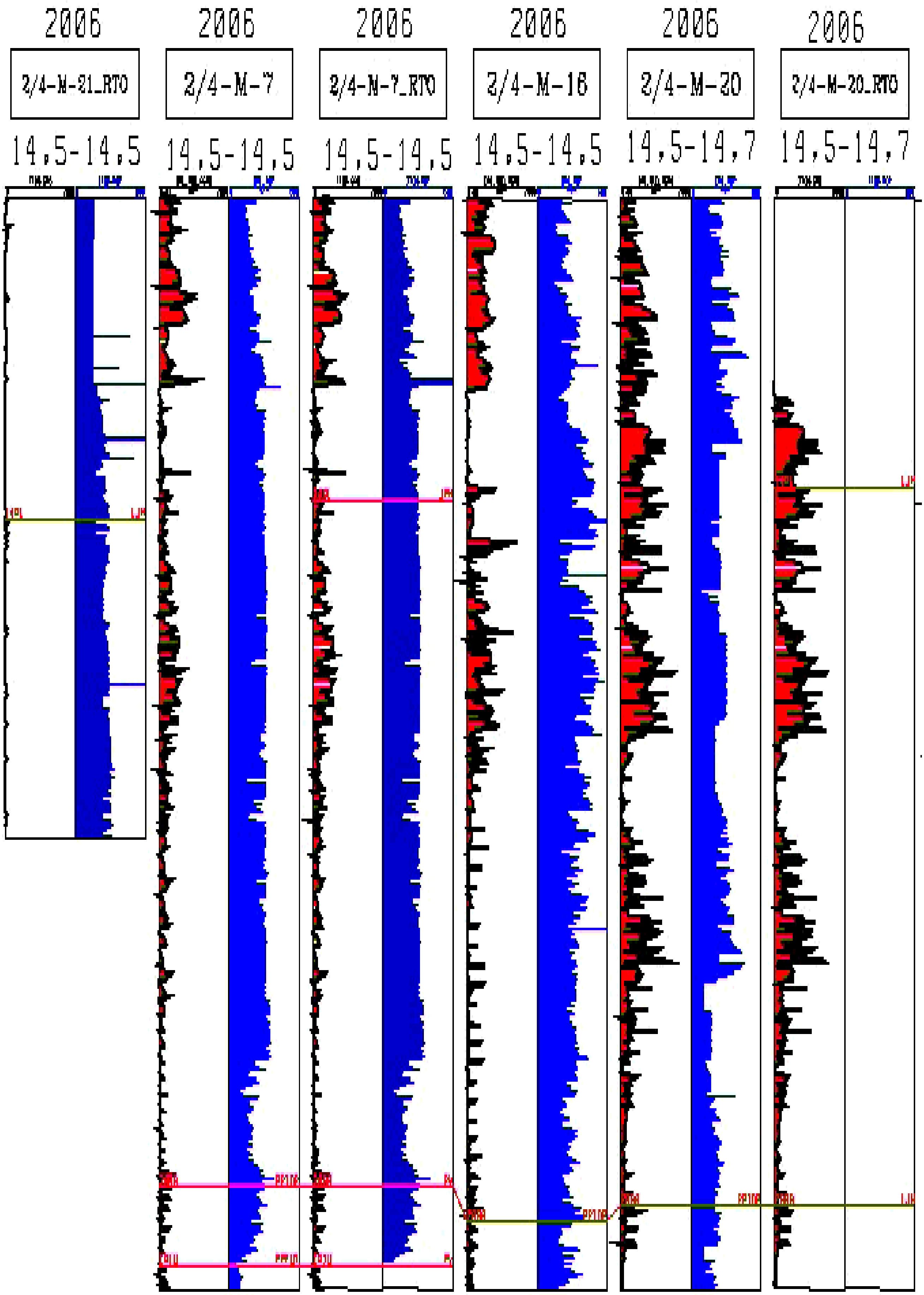

2002
2/4-X-49
14,5-14,7
2002
2/4-X-49 T2
14,8-14,8
2003
2/4-X-29
14,7-14,9
2003
2/4-X-11
14,5-14,8
2003
2/4-X-14
14,5-14,7
2003
2/4-X-50
14,5-14,3
PPTOP
2OBA
PPTOP
LJH
PPFU
PPTOP
PPFU
PPTOP


2003
2/4-X-41
14,5-14,7
2003
2/4-X-22
14,4-15,0
2004
2/4-X-23
14,2-14,5
2004
2/4-X-25
14,5-14,7
2004
2/4-X-24
11,0-12,5
2004
2/4-X-13 AT2
14,6-14,5
2004
2/4-X-13 A
14,4-14,7


2004
2/4-X-13 A
14,4-14,7
2004
2/4-X-24 T2
12,6-14,4
2004
2/4-X-21 Y1
14,5-14,6
2005
2/4-M-18
14,5-14,5
2005
2/4-M-18_RTO
14,5-14,5
2005
2/4-M-17
14,5-14,5


2005
2/4-M-17_RTO
14.5-14.5
2005
2/4-X-30
14.5-14.8
2005
2/4-M-23
14.5-14.5
2005
2/4-M-22
14.5-14.7


2005
2/4-M-24
14.5-14.5
2005
2/4-X-4 A
14.5-14.7
2005
2/4-X-4 A_RTO
14.5-14.7
2005
2/4-X-28
14.5-14.7
2005
2/4-X-28_RTO
14.5-14.7
2006
2/4-M-21
14.5-14.5


2006
2/4-M-21_RTO
14,5-14,5
2006
2/4-M-7
14,5-14,5
2006
2/4-M-7_RTO
14,5-14,5
2006
2/4-M-18
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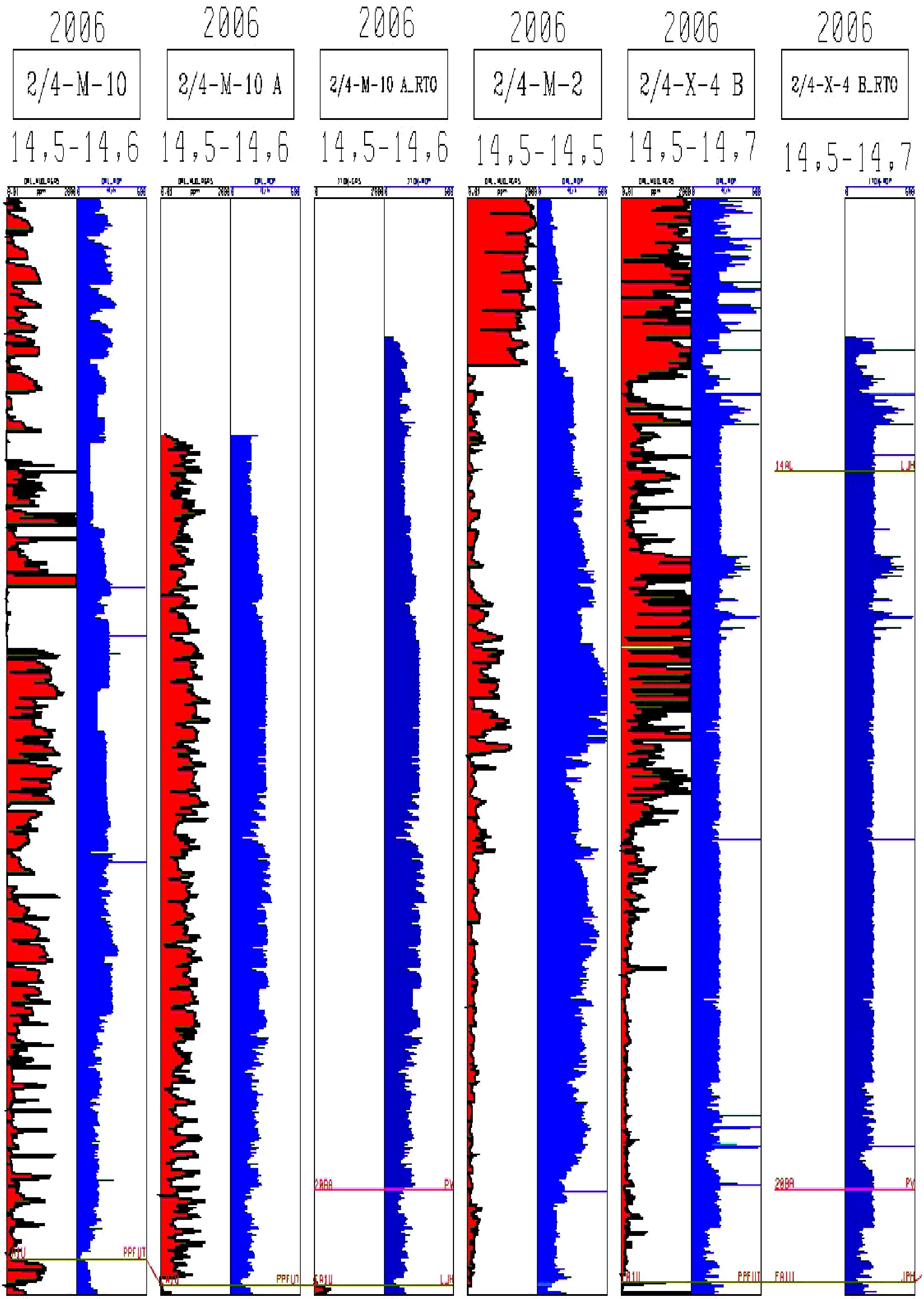
14,5-14,7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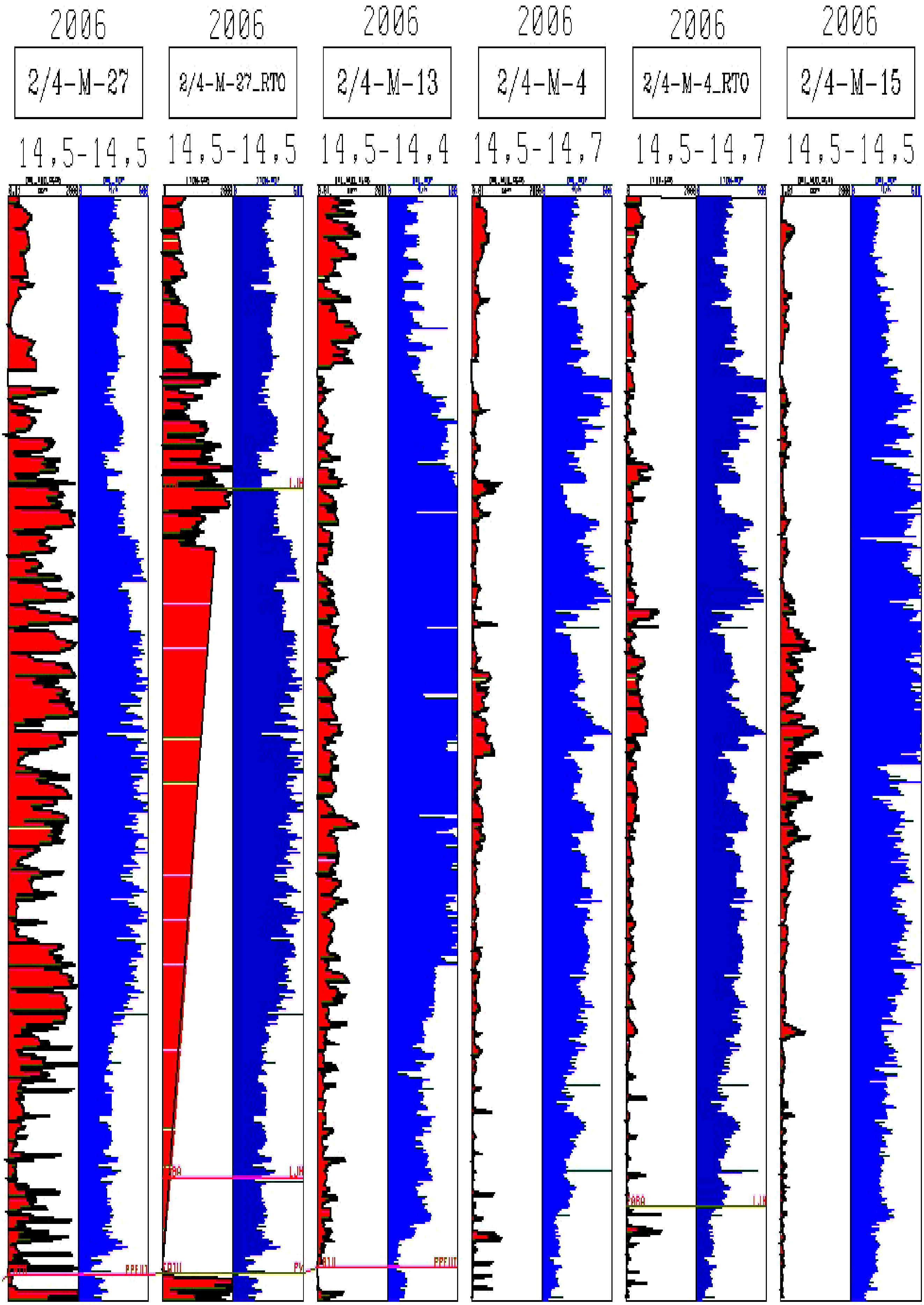
2/4-M-10
14,5-14,6
2006
2/4-M-10 A
14,5-14,6
2006
2/4-M-10 A_RTO
14,5-14,6
2006
2/4-M-2
14,5-14,5
2006
2/4-X-4 B
14,5-14,7
2006
2/4-X-4 B_RTO
14,5-14,7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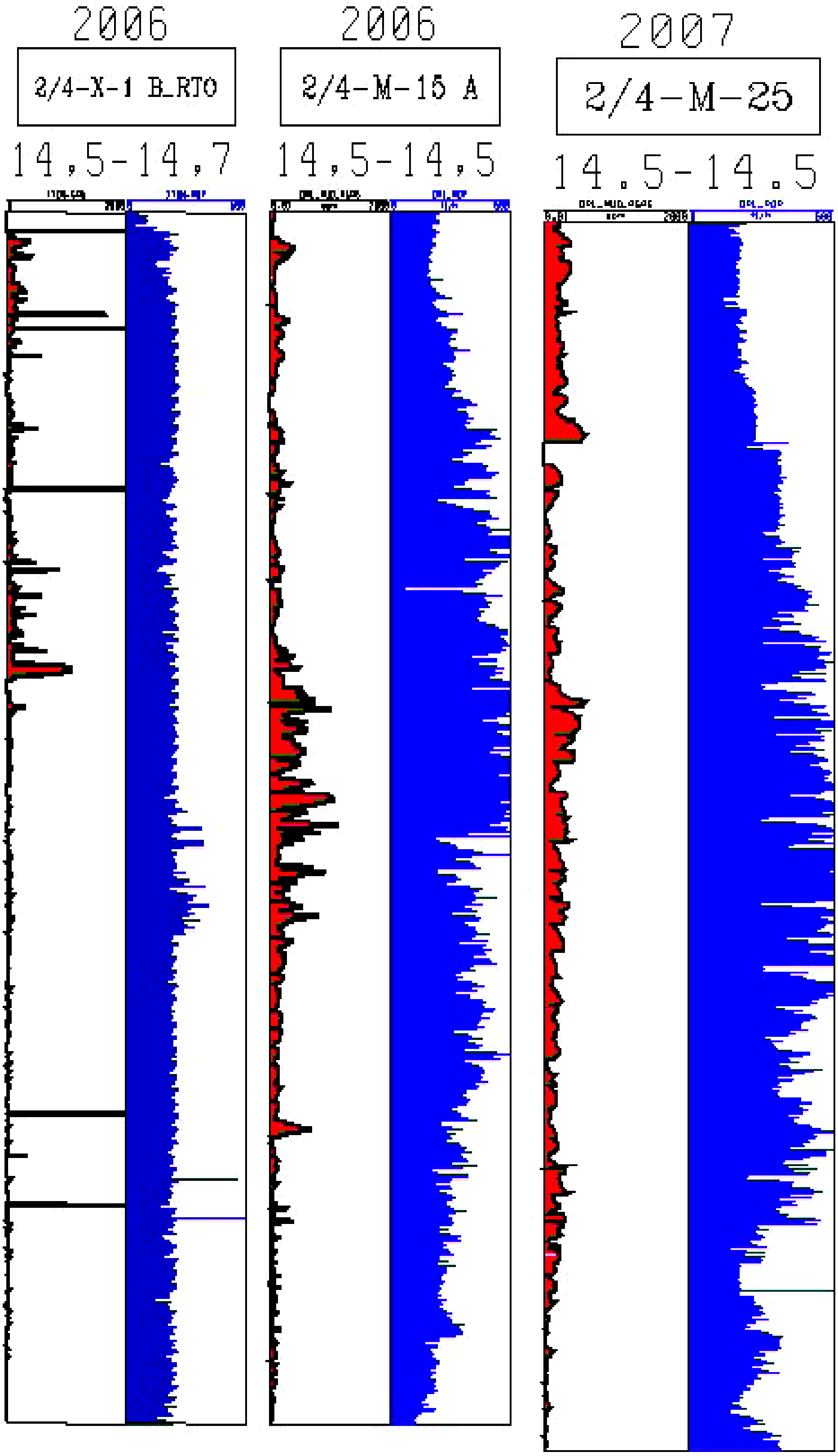
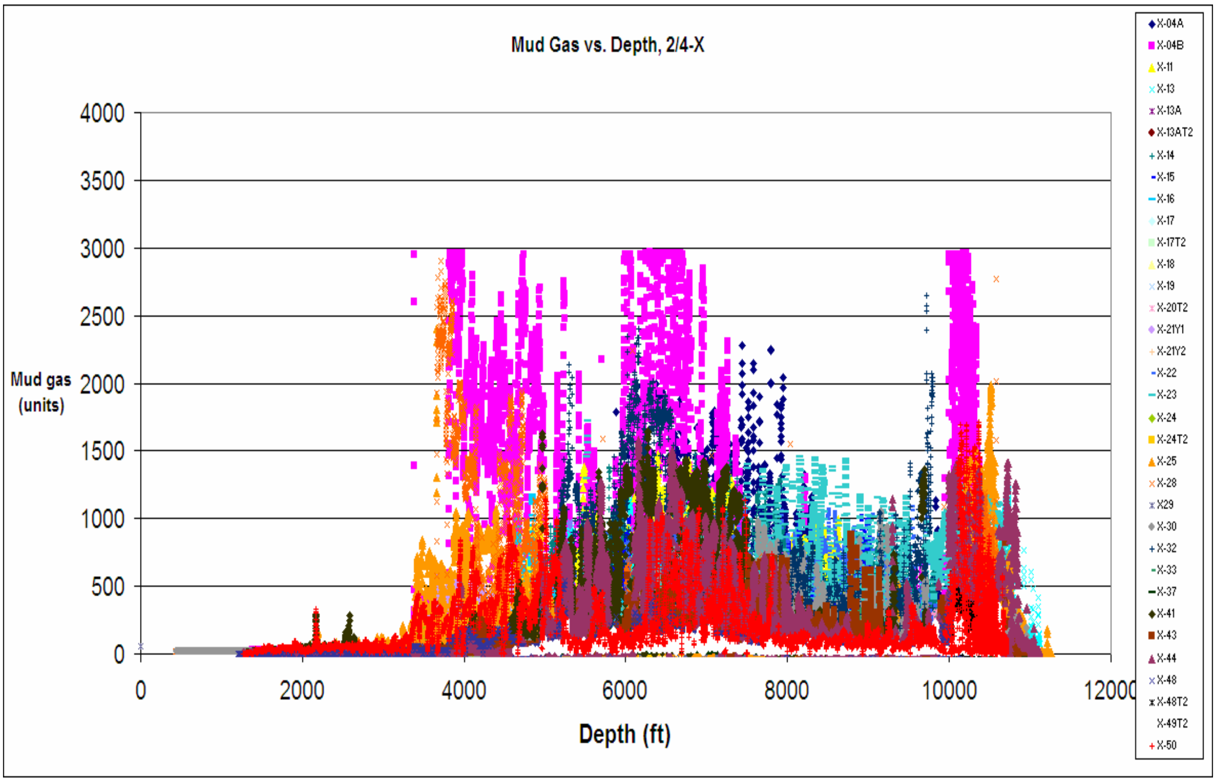
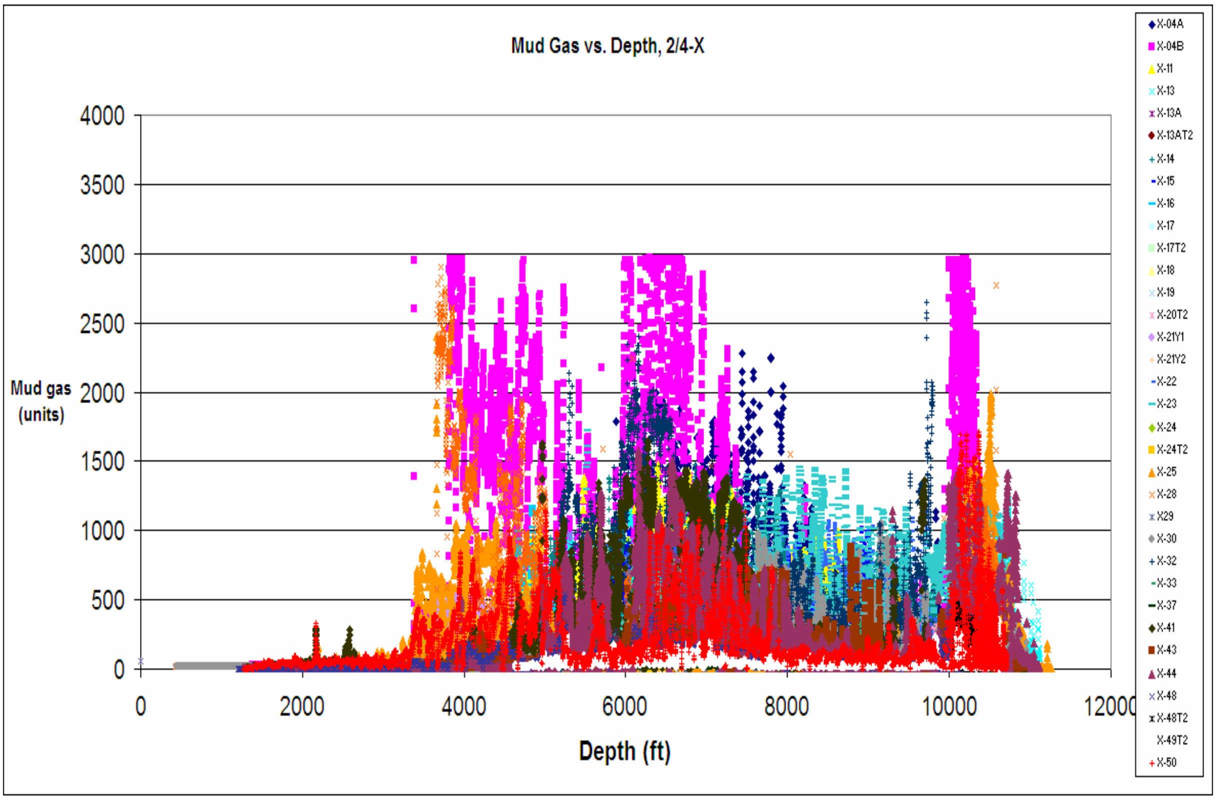
2/4-M-27
14,5-14,5
2006
2/4-M-27_RTO
14,5-14,5
2006
2/4-M-13
14,5-14,4
2006
2/4-M-4
14,5-14,7
2006
2/4-M-4_RTO
14,5-14,7
2006
2/4-M-15
14,5-14,5

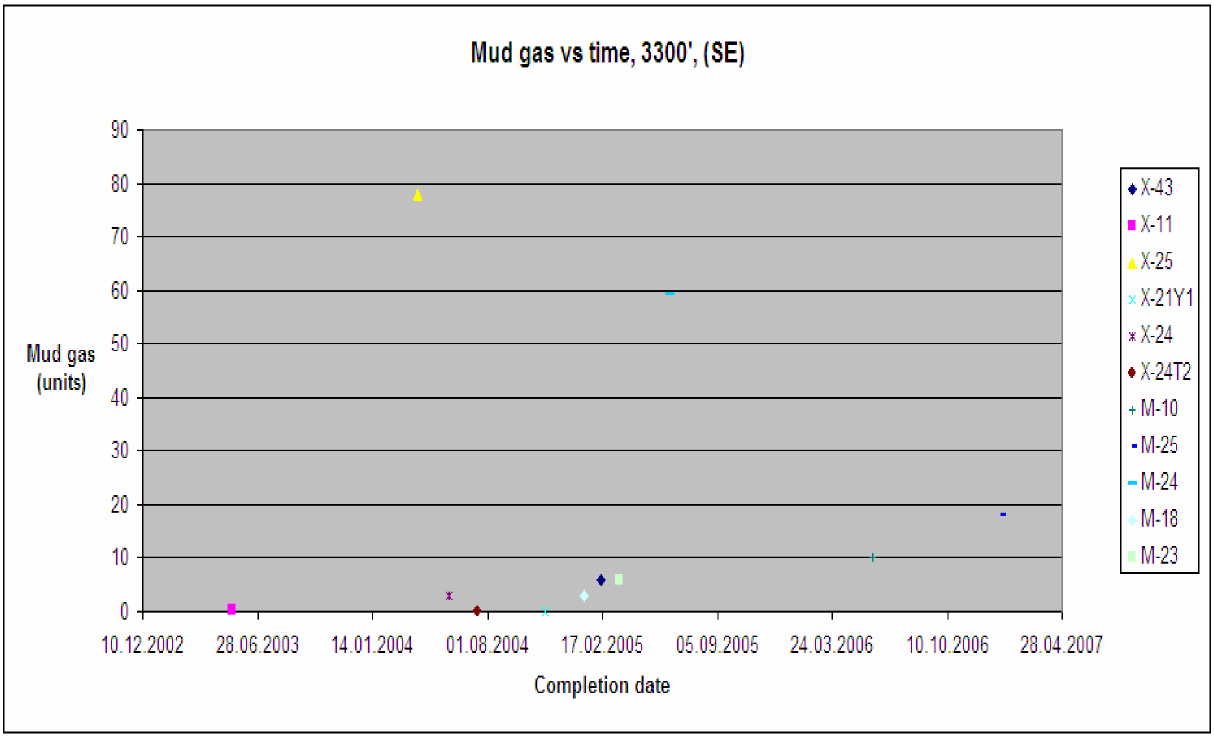

2006
2/4-X-1 B_RT0
14,5-14,7
2006
2/4-M-15 A
14,5-14,5
2007
2/4-M-25
14.5-14.5

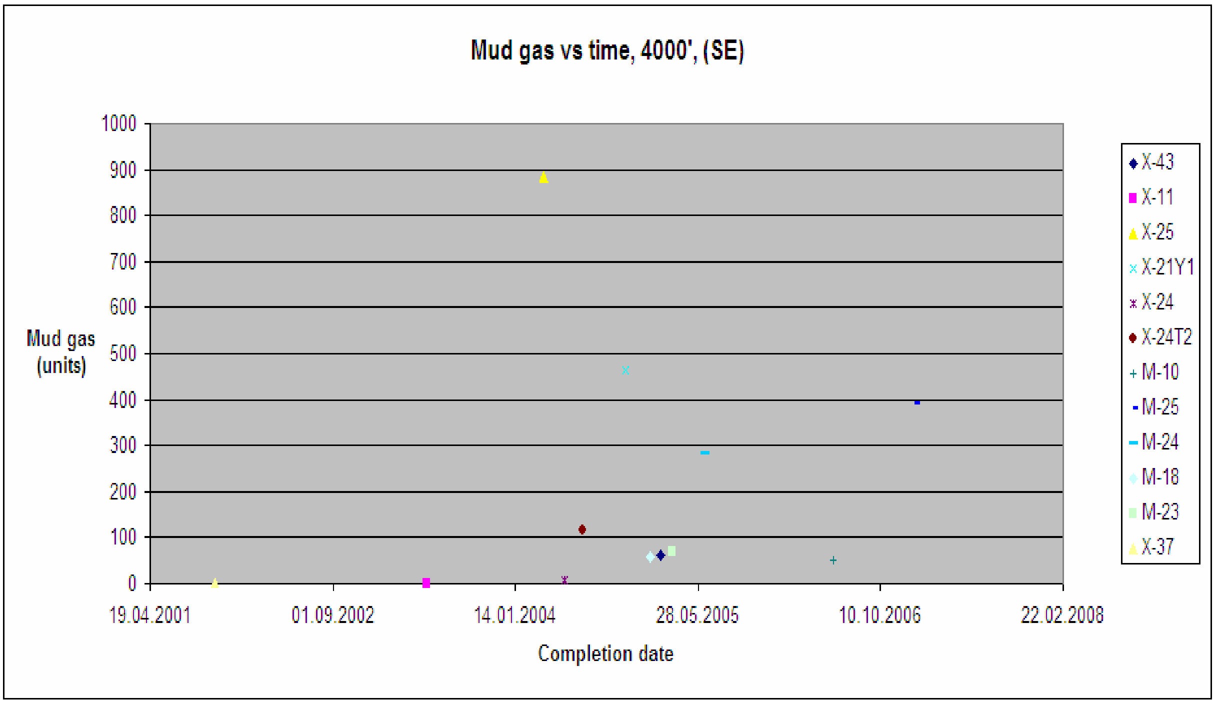
B. Graphs of Mud gas vs. Depths

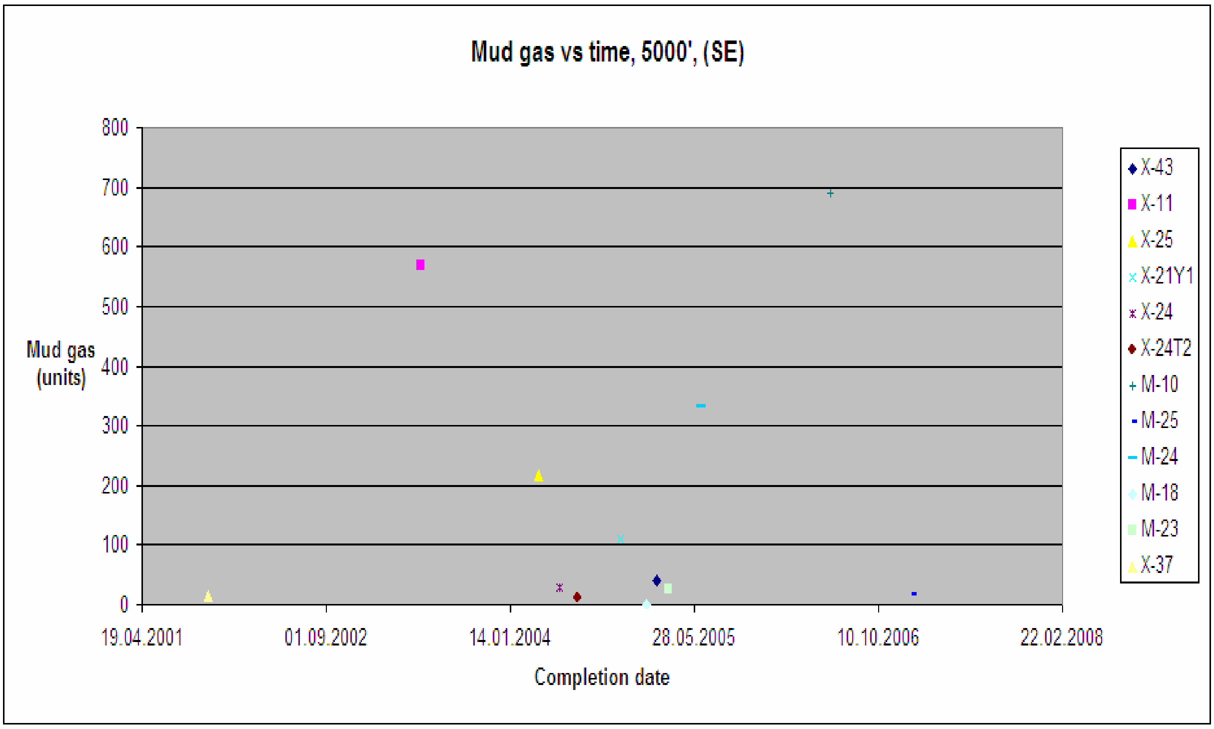


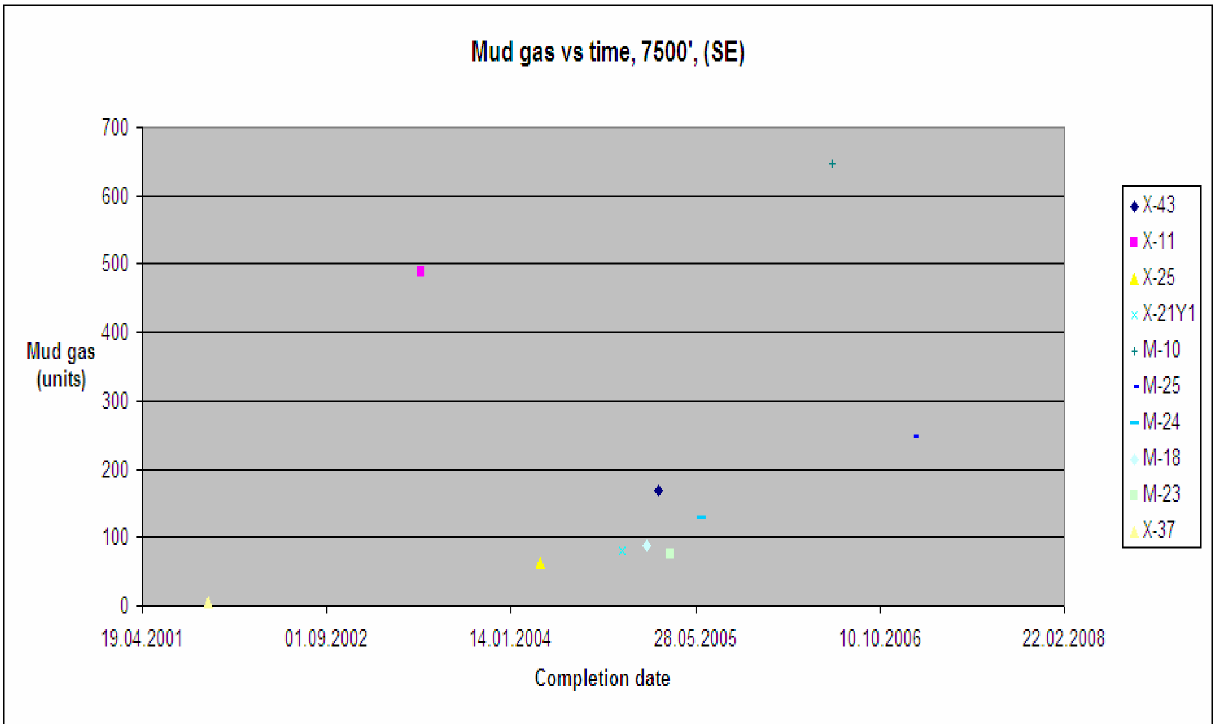


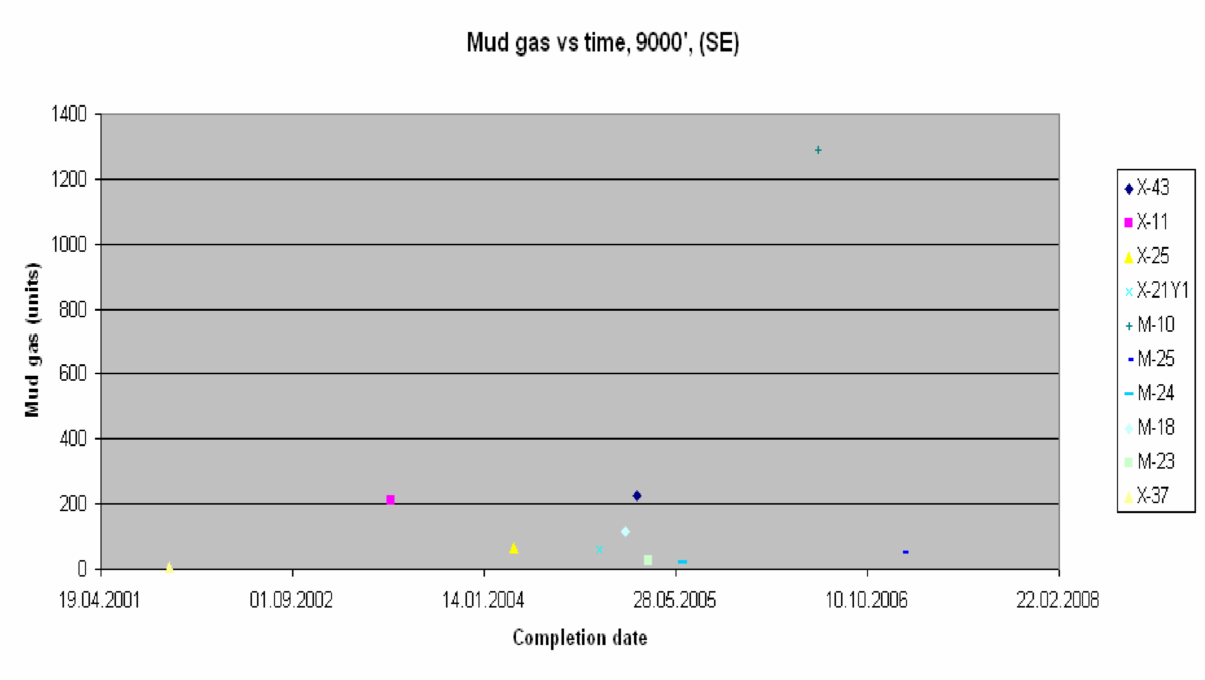
C. Graphs of Mud gas at different depths vs. time



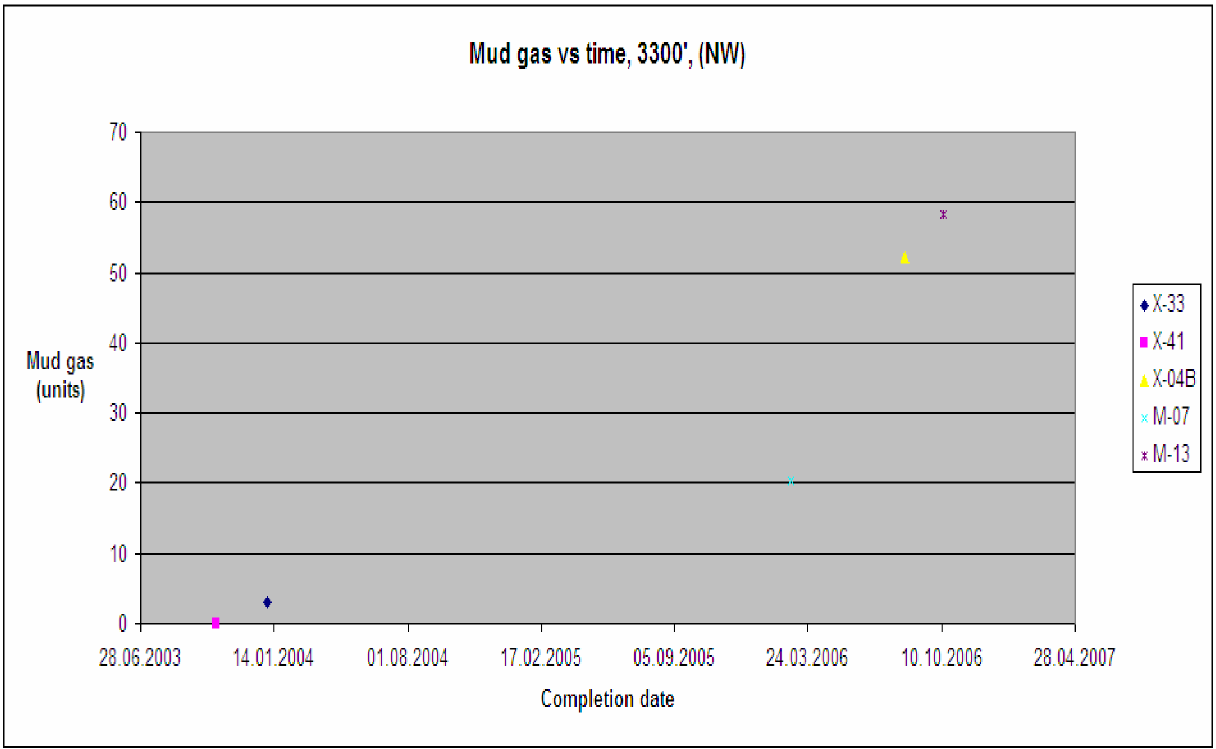



Mud gas vs time, 5000', (SE)
800
700
600
500
400
300
200
100
0
Mud gas (units)
19.04.2001
01.09.2002
14.01.2004
28.05.2005
10.10.2006
22.02.2008
Completion date
X-43
X-11
X-25
X-21Y1
X-24
X-24T2
M-10
M-25
M-24
M-18
M-23
X-37

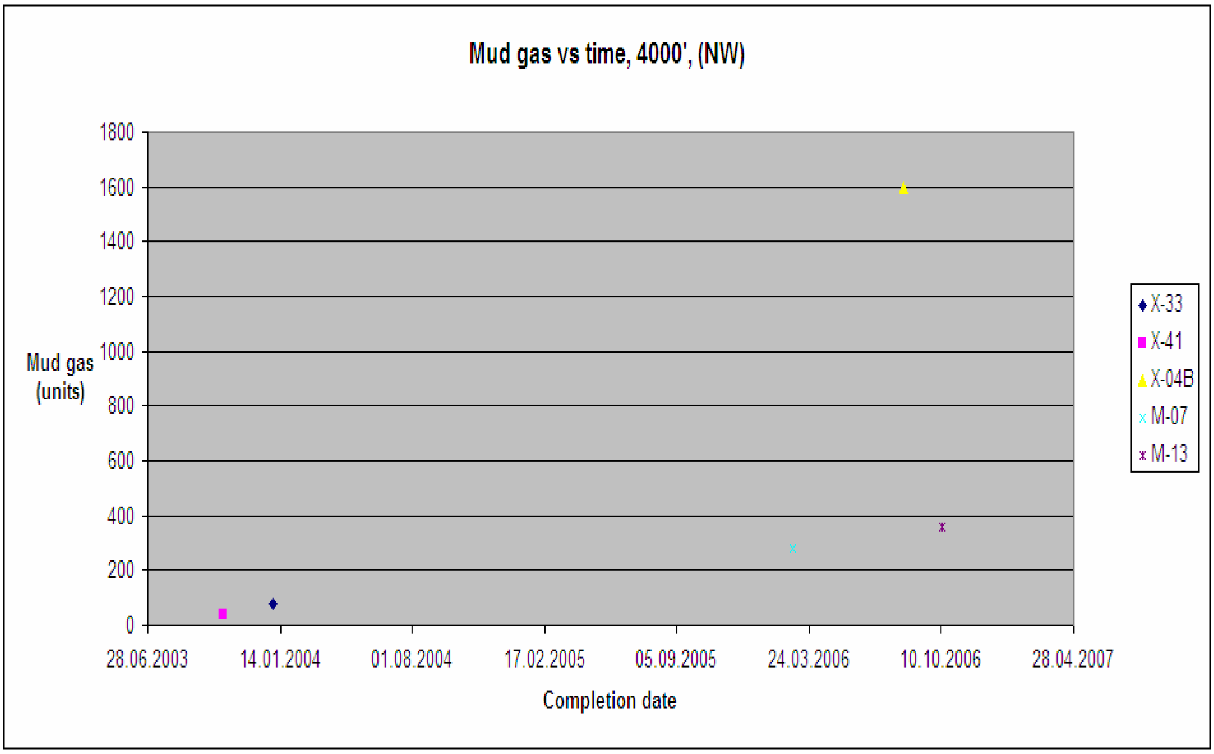

Mud gas vs time, 7500', (SE)
700
600
500
400
300
200
100
0
Mud gas (units)
19.04.2001
01.09.2002
14.01.2004
28.05.2005
10.10.2006
22.02.2008
Completion date
X-43
X-11
X-25
X-21Y1
M-10
M-25
M-24
M-18
M-23
X-37

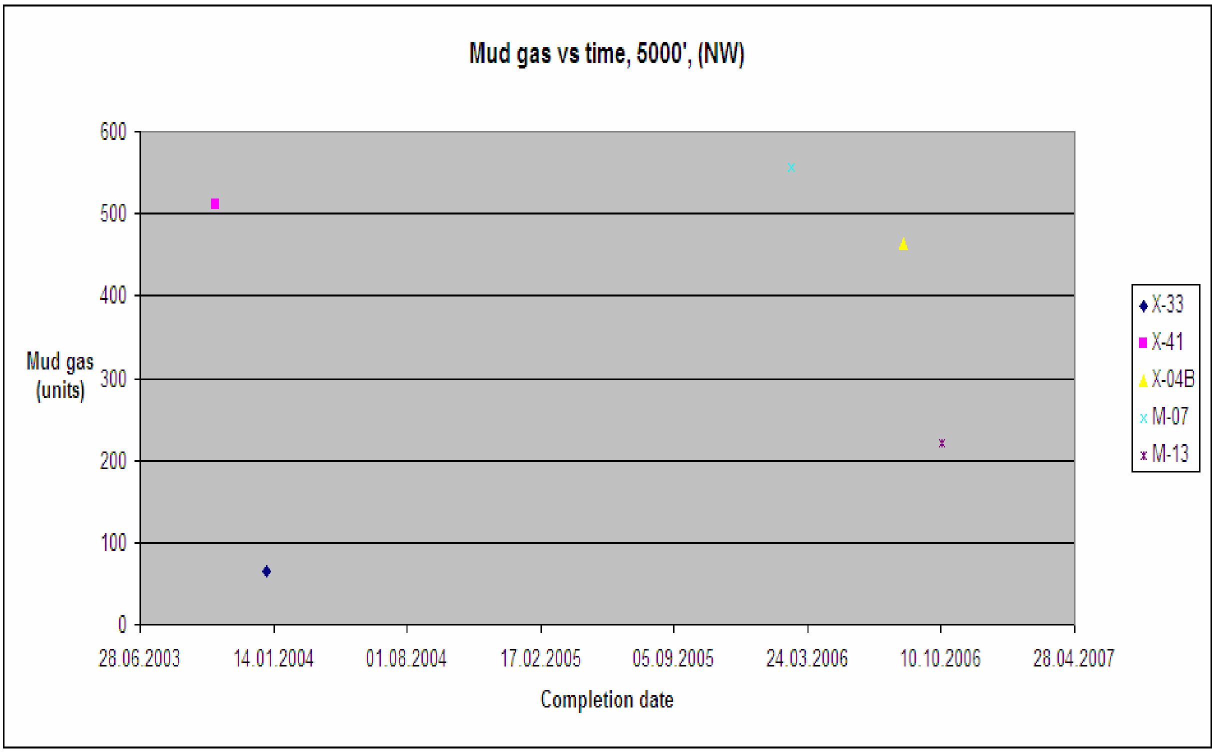


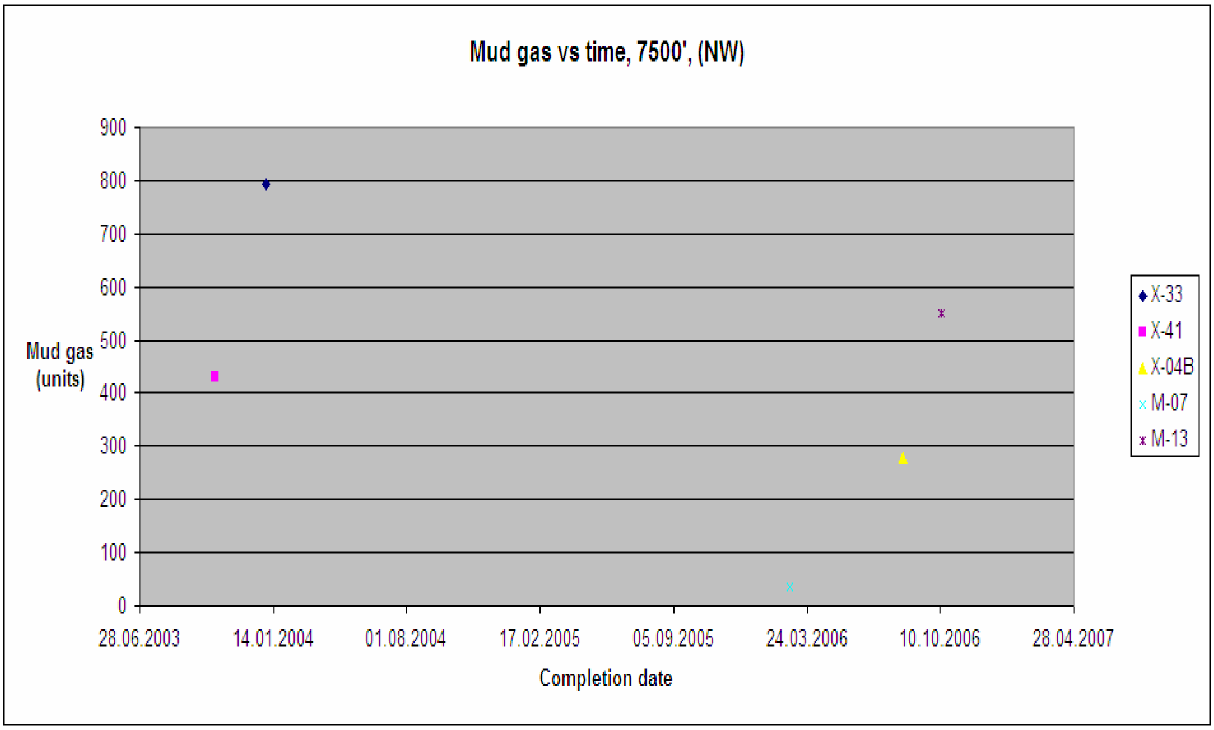
Mud gas vs time, 9000', (SE)
Mud gas (units)
1400
1200
1000
800
600
400
200
0
19.04.2001
01.09.2002
14.01.2004
28.05.2005
10.10.2006
22.02.2008
Completion date
X-43
X-11
X-25
X-21Y1
M-10
M-25
M-24
M-18
M-23
X-37

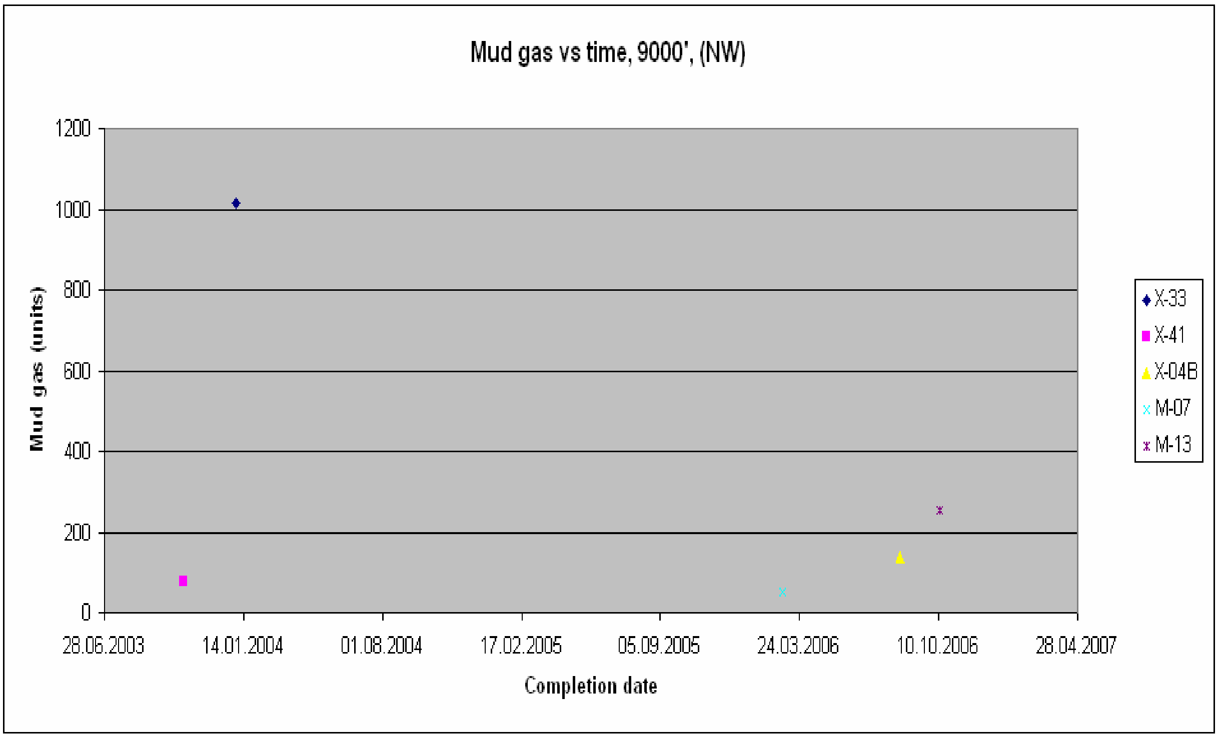


Mud gas vs time, 3300', (NW)
Mud gas (units)
70
60
50
40
30
20
10
0
28.06.2003
14.01.2004
01.08.2004
17.02.2005
05.09.2005
24.03.2006
10.10.2006
28.04.2007
Completion date
X-33
X-41
X-04B
M-07
M-13


Mud gas vs time, 4000', (NW)
Mud gas (units)
1800
1600
1400
1200
1000
800
600
400
200
0
28.06.2003
14.01.2004
01.08.2004
17.02.2005
05.09.2005
24.03.2006
10.10.2006
28.04.2007
Completion date
X-33
X-41
X-04B
M-07
M-13


Mud gas vs time, 5000', (NW)
Mud gas (units)
600
500
400
300
200
100
0
28.06.2003
14.01.2004
01.08.2004
17.02.2005
05.09.2005
24.03.2006
10.10.2006
28.04.2007
Completion date
X-33
X-41
X-04B
M-07
M-13


Mud gas vs time, 7500', (NW)
900
800
700
600
500
400
300
200
100
0
Mud gas (units)
28.06.2003
14.01.2004
01.08.2004
17.02.2005
05.09.2005
24.03.2006
10.10.2006
28.04.2007
Completion date
X-33
X-41
X-04B
M-07
M-13


Mud gas vs time, 9000', (NW)
1200
1000
800
600
400
200
0
Mud gas (units)
28.06.2003
14.01.2004
01.08.2004
17.02.2005
05.09.2005
24.03.2006
10.10.2006
28.04.2007
Completion date
X-33
X-41
X-04B
M-07
M-13