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Thesis

METHODS OF MONITORING FLOW PATHS IN THE GAISELBERG-FIELD WITH A SPECIAL FOCUS ON TRACERS

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1. Introduction

Since 1970 water-flooding has been applied in the Gaiselberg Field. At present twelve injectors inject the produced water back into the reservoir. The Gaiselberg Field can be regarded as very complex, hence large uncertainties exist how channel communication, barriers or communication behind casings would affect the overall sweep and reduce the possibility for efficient sweep.

The scope of this thesis is to identify and review possible surveillance methods to asses the water-flood in the Gaiselberg Field and to identify possible channel flow. The results should enable to develop a new water-flooding strategy to increase the recovery factor of the Gaiselberg Field.
The author decided to review the following surveillance techniques:

- Simulation (chapter 2)
- Production Data (chapter 3)
- Material Balance (chapter 4)
- Salinity Survey (chapter 5)
- Tracer (chapter 6-9)

1.1 Water Flood Asset Management

The injection of water, on the one hand for secondary recovery reasons and on the other hand to maintain the pressure in the reservoir, is one of the oldest techniques used in petroleum industry. An enormous progress in the design, development and surveillance of water-flooding projects can be observed over the years. However, it must be said that most of the attention is paid on the design and development phase although surveillance is indispensable to guarantee a successful water-flooding project.[1]

Besides high sophisticated simulation or observations via satellite also easy-to-use techniques for the surveillance of injection wells or water flood projects are available:[1]

- Hall Plot
- WOR-plot
- GOR-plot
- Voidage Replacement
- Voidage Replacement Ratio

These plots are described more in detail in chapter 3 and 4.

The water flooding project should be launched at an optimal time to increase the recovery and to maximize profits. Basically it can be said that the optimum time for the initiation of the water-flooding depends on the operator's primary objective:[1]

- Maximizing oil recovery
- Maximizing future net worth
- Maximizing rate of return
- Stabilizing monetary return
- Maximizing net present value

In a homogenous reservoir water-flooding should be started when the bubble point is reached to ensure maximum oil recovery. This can be explained with the high free-gas saturation in residual oil and the favorable effect on oil viscosity. However, most of the reservoirs are not homogenous in nature and hence the highest oil recovery is expected for pressures which are lower than the bubble point pressure.[1]

Another constraint of the water-flood initiation condition is low bubble point pressure. The production rates may already have significantly declined so that water-flooding becomes unattractive. In this situation it would be wise to initiate the water-flooding much before the bubble point pressure is reached. These examples show that the time of initiating the water-flood is a crucial step and needs an integrated reservoir management during the production-lifetime of the reservoir. As already mentioned in the introduction of this thesis not only the planning of the water-flooding is important but also the water-flood surveillance and asset management.[1]

WATERFLOOD ASSET MANAGEMENT (WAM)

As a matter of fact the water-flood program is an important part of reservoir management. WAM includes the following steps:[2]

1. Identification of the water-flood need
2. Feasibility plan (technical and economical): involves, assessing the feasibility of the process, economical feasibility under extreme conditions and selection of the injection pattern with the corresponding producers
3. Schedule and implementation of the plan: preparing the technical implementation, scheduling the surface facilities, timeline for injector and

injection profile, data-collection plan for later surveillance and monitoring purposes, and the execution of the implementation.

4. Surveillance and monitoring: including data acquisition, streaming, data-mining and the visualization of data (Hall plot, WOR plot, GOR plot, VRR, pressure fall-off study). Those plots provide a basis for data-analyses and performance monitoring of injectors and/or the water-flood project.
5. Assessment of reservoir performance: including production performance, reservoir pressure response and therefore injection scheduling.
6. Modification and/or Correction of the plan – future strategy.

The points mentioned above are interdependent and are supposed to be implemented into the reservoir management to guarantee a successful water-flood project.

The review of operator's water-flood projects shows that most of the attention is paid to the planning phase and the reservoir performance assessment. This is also reflected by the fact that most attention is concentrated on software, equipment and support for this purpose. Significantly less attention is paid to surveillance and monitoring. But without doubt, these areas are very important for a successful water-flood.[1]

The surveillance issue addresses the necessity of reservoir description, reservoir performance, sweep efficiency, injector producer behavior, water quality, reservoir response, facilities and equipment maintenance, troubleshooting, potential problem analysis and budget control.[1]

A surveillance program can include the following points:[1]

- data acquisition
- monitoring of reservoir performance by
    - pressure
    - rate
    - volumetric sweep
    - communications/barriers
    - channels
    - thief zones

- monitoring of:
    - producers

  - injectors
  - facilities
  - water system

1.2 Gaiselberg Field

The Gaiselberg Field is located roughly 40 km NE of Vienna, in the Vienna Basin, and was discovered by RAG in 1938. Until now (31.12.2006) the field has produced 5.82 Mm^3 of oil and 489 Mm^3 of gas from 89 wells and 101 boreholes drilled in the field. From the 89 wells, 66 were drilled pre-1945 (war years), 6 drilled between 1947 and 1956 (SMV years), 14 drilled between 1976 and 1986 (re-newed production interest by RAG) and 3 in the last years.[3]

It can be seen that the production of the field peaked in 1942 and has been declining ever since. In the mid-1990's it was clear that a new type of prospect was needed, and in order to locate these prospects, 3D seismic was acquired over Gaiselberg. For further detail the author refers to Reference [3].

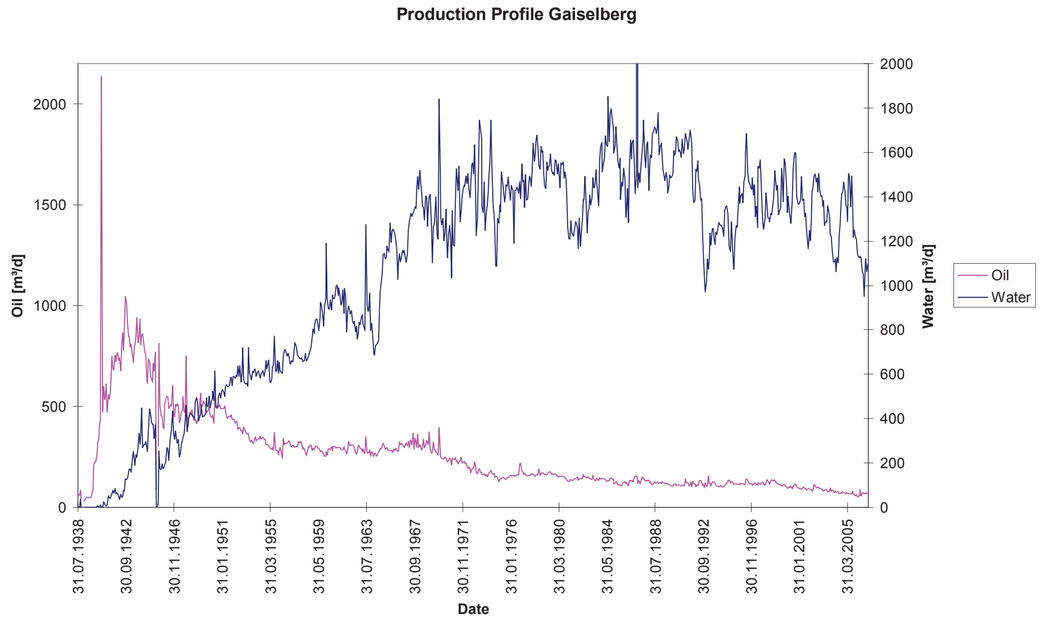


Fig.1.1: Production Profile of the Gaiselberg Field

1.2.1 STRATIGRAPHY

Four main stratigraphic units are found in the Gaiselberg subsurface: Pannonian, Sarmatian, Tortonian and Flysch. In some work Tortonian unit is also named 'Baden

Series'. No Carpathian – age sediments have been drilled in the Gaiselberg Field so far, although their existence in the Vienna Basin was proved by OMV wells. The Badenian to Pannonian units represent a gradual transition from open marine sedimentation (Badenian), through Brackish Marine sedimentation (Sarmatian) through Half-brackish, restricted-marine sedimentation (Pannonian). Until now no higher stratigraphic units, like Pontian, have been drilled so far.[3]

Due to the fact that most of the oil and gas potential is encountered in the Sarmatian units the thesis is focused on those units. This is also the reason that this geological review will also focus on the Sarmatian units. For further details about the others see Reference [3].

1.2.1.1 Sarmatian

The Middle-Late Miocene Sarmatian is a package with a thickness of 900+ m of siliclastic sediments deposited in a marine-deltaic near-coastal setting. The Sarmatian layers do no outcrop the concession boundaries but subcrop against the Steinberg fault, in the central southern and eastern part of the Gaiselberg Field. In contrast to other sediments (e.g. Badenian) the Samartian, in small-scale cycles, often coarsen upwards, with thick packages of sand at the top of each cycle. Between those cycles a massive shale package can be found. On a larger scale, e.g. between 17th Sarmat and 20th Sarmat, the cycles seem to fine upwards.

Previous field studies [4],[5] subdivided the Sarmatian package of Gaiselberg into 20 main units, based mainly on SP-log correlation. Individual 'main units' are subdivided into smaller-scale reservoir units. This was done based on presumed flow barriers. This thesis follows this subdivision. Older data, which were recorded before this subdivision was done, were updated with the help of the new interpretation, by the author. This was necessary to make them comparable with present data.[3]

The Sarmatian sediments in Gaiselberg can be divided into 3 parts: upper, middle and lower. Lithologically and genetically, the three units are similar. The lower Sarmatian include the layers between Sarmat 16/4 and the 20th Sarmat, the middle layers between the 11th Sarmat and Sarmat 16/3, the upper layers between the 1st and the 10th Sarmat. This subdivision follows the main hydrocarbon seals in Gaiselberg, as evidence from major shifts in OWC's. The author of this thesis decided to divide the Sarmatian sediments of the Gaiselberg Field into two parts. 'Part 1' is identical with the middle part of the work of Vogel[3]. 'Part 2' is equal to the lower part of Vogel[3] but without the Sarmatian units 16/4 to 17/1. They are excluded from 'Part 2' mainly because of the reason that their sediments are very rare and sporadic.[3]

The marine fauna is gradually displaced by a more restricted, more brackish and more shallow-water fauna. The boundary to the Pannonian is also the transition between brackish and half-brackish.

The sands and shales of the lower Sarmatian were likely deposited by a deltaic system – also the Upper Badenian sediments are similar in the nature of the environment. Due to fact that the environment of deposition became more restricted, shallow and brackish, the typical deltaic cut-and-fill channel sedimentation is predominated, which is indicated by the coarsening-upward features noticed in the small scale-cycles. The good lateral continuity of the Sarmatian sediments indicates that storm-influenced and erosion played an important role. Thicker shale units (e.g. 8th Sarmat) were likely deposited in periods of channel abandonment, i.e. where the bulk of sand being deposited in the delta lay somewhere else.[3]

1.2.2 STRUCTURAL GEOLOGY

The fields in Lower Austria (Rag, Gaiselberg, Hohenruppersdorf) show pronounced strike-slip faulting, caused by several Miocene to recent compressional events due to the Africa-Adria-Europe plate collision[6]. ‘While the Early Miocene N-S compression resulted in thrusting and foreland imbrication, the later compressional events resulted in a transpressional/transtensional lateral extrusion of the sediments towards the East along large strike-slip faults. These large NNE-striking sinistral strike-slip faults, such as the Steinberg fault, dominate the structuration of the Lower Austrian fields’[3]. These faults play an important role in the creation of hydrocarbon traps. The Steinberg fault also separates the Paleocene – Eocene Flysch of the Zistersdorf and Gösting Nappes from the Miocene age sediments of the Vienna Basin. A large portion of hydrocarbons in Lower Austrian fields are trapped where the Miocene age sediment abuts against the Steinberg Fault.[3]

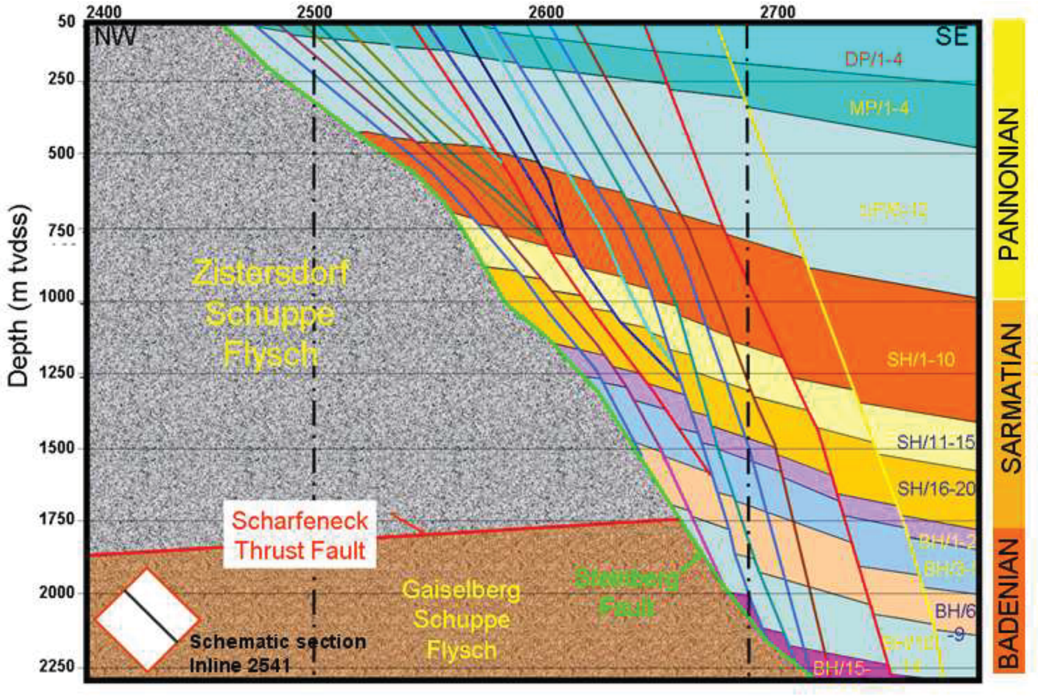


Fig.1.2: Cross Section along Inline 2541[3]

In cross-section (Fig.1.2), the negative flower structure, caused by transtensional stress regime, can be seen, with faults converging at depth. This negative flower structure is also responsible for the creation of the ‘rollover anticline’ of the strata, seen in the cross-section. Faults in the Gaiselberg Field typically trend NNO-SSW, which is parallel to the Steinberg Fault, and strike-slip movement is minor. The through along a fault increases with depth and many of the smaller faults join at depth, so that the faults remaining at depth show large throws. It is assumed that the faults having a larger offsets are sealing, causing reservoir compartmentalization, although evidence indicates that a few faults were occasionally breached, resulting one compartment draining into a higher one. With over 30 main faults mapped in the 2,5km² Gaiselberg concession, the fault density is very high.[3]

Other structuration is due to the transpressional stress, which causes occasionally layer-thickening and layer-doming.[3]

1.2.3 HYDROCARBON TRAPS

The typical trap in the Gaiselberg Field consists of a shale-capped, laterally fault-bounded reservoir sand – not filled up to the spill point.[3]

1.2.3.1 Seals

The top seals of the traps are shales and marlstones. The presence of a thick, impermeable sediment package is a constitutive of a thick hydrocarbon column – major shifts in depth of the Oil-Water-Contacts occur below those thick shale and marlstone sequences (e.g. 10th Sarmat and Sarmat 16/5-9 sequences). In general, the thicker the seals are, the bigger the shift of the Oil-Water Contact.[3]

Laterally, traps are usually sealed by faults, although in some horizons (e.g. 18th – 19th Sarmat), the reservoirs tend to shale out laterally, also providing a lateral seal. In some cases the shift in depth of the OWC is obvious (see reservoir top map of Sarmat 16/1) which indicates the lateral sealing capacity of the faults. Clay smearing plays an important role in determining the sealing capacity of a fault. Alternatively, the fault can juxtapose a reservoir sand next to a sealing shale. Occasionally it was noted, from production data and OWC shift, that faults with sub-seismic throw can act as an flow barrier. The Steinberg Fault also provides a very important lateral fault, although evidence suggests that a hydrocarbon loss across the fault may occur, where sandstones are juxtaposed.[3]

An example can make that descriptive: GA-066 and GA-066-A were both dry wells although the horizons were expected to be oil-bearing. This can be explained with the fact that the faults F6, F7 and F8, which intersect to the south of the well, prevented the block of being charged. Because of the large through over the faults, they are almost certainly sealing. The hydrocarbon charge, entering Gaiselberg from the south, could not charge the compartments across these faults.[3]

1.2.3.2 Reservoirs

Usually high-quality reservoirs are present in the Gaiselberg Field. ‘Thick, high porosity, high permeability, sandstones are abundant throughout the stratigraphic column.’ [3]

1.2.4 HYDROCARBON OCCURRENCE

Hydrocarbons occur in most of the stratigraphic units – hydrocarbons are found between UP/10 (Pannonian) and BH/14 (Baden). The uppermost layers, from UP/10 to SH/10(Samatian) are gas-prone (no oil has been discovered until now) but the volumes related to those units are fairly small.

The bulk of hydrocarbons in Gaiselberg was produced from Sarmatian layers (11th -20th Sarmat). Over 5.29 Mm^3 of oil and over 391.3 Mm3 of gas were produced from those units. In total the field has produced 5.82 Mm^3 of oil and 489 MMm^3 of gas. [3]

2. Simulation

2.1 Introduction

When a conventional technical component is developed, in most cases a prototype is manufactured. This prototype can be used for testing purposes to improve the component – this is a step by step improvement. This kind of development and improvement is not applicable to all real systems, mainly because of one of the following circumstances:[7]

- the system is unique
- the system is inaccessible
- the system is too large or too small
- the life cycle is too long

All four circumstances are appropriate to a hydrocarbon reservoir. In such a case only the following possibilities of modeling are left:[7]

- physical
- analogous
- numerical

The basic idea behind, for all of them, is to formulate the most important physical and chemical processes in a mathematical model. This mathematical model makes it possible to replace a real process by a similar, but easier to accomplish, process.[7]

As a matter of fact no mathematical model is perfect due to the fact that they are only approximations of the real physical process. In most instances they even have to be simplified to make solvable. In many cases the model only describes the most important physical and chemical processes. It is important to state at this point that only processes which are mathematically modeled can be examinated later on.[7]

Basically, one can use a mathematical model in two modes:[7]

- as a modeling tool (analytical mode)
- as a simulation tool

This classification is also shown in figure 2.1. The analytical mode needs correct mathematical equations which are based on experimental evidence to produce a correct output. The simulation mode, however, matches the calculated results with the real system behavior which allows a tuning of the model. Even tuning with no physical background is allowed and often used.[7]

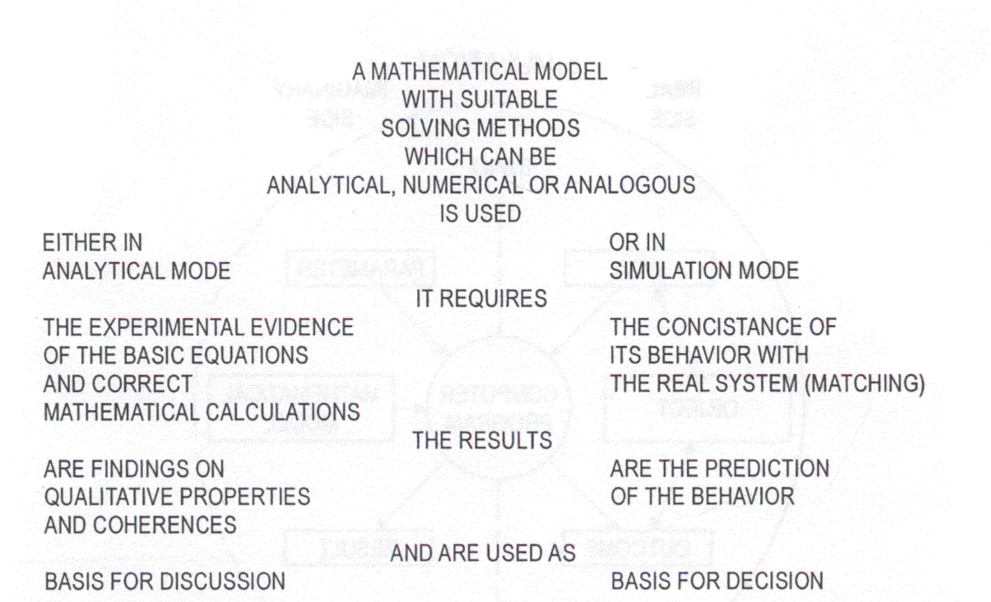


Fig.2.1: Use mathematical model in analytical and simulation mode[7]

It is important to state that the classification in figure 2.1 is independent of the solving method which can be analytical or numerical. In most cases the mathematical models which are used in simulations are so complex that only numerical solutions are possible. Numerical models used for simulations are usually called simulations model even if they are used for analytical purposes.[7]

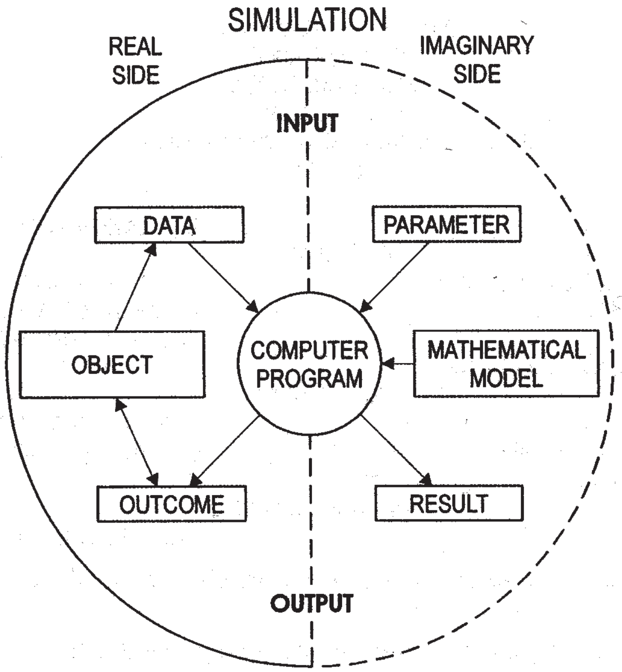


Fig.2.2: The nature of numerical simulation [7]

The basic principle of numerical simulation is visualized in figure 2.2. Basically it can be said that the simulation has two sides: a real and an imaginary one. Naturally input data are required to feed the model which is measured on the reservoir (object). The parameters are matched in a way that the output of the model coincides with the measured data from the reservoir. The bigger part of the output cannot be compared with real field data but can be taken as seriously if the previous matching was successful. It is very important to notice that without reliable data the model will not be able to solve the real problem.[7]

Reservoir simulation makes it possible to get an insight view into the recovery process of a hydrocarbon reservoir – basically fluid flow is described to evaluate the performance of oil and gas recovery methods. Important processes can be described with partial differential equations which account for mass and heat transfer including terms for gravity, capillary and viscous forces. In case of water flooding reservoir simulation can evaluate the performance of different scenarios and can help to decide on which injection strategy is applied.[7]

2.2 Input Data

As mentioned above, without reliable data a simulation will not give a feasible output. This chapter will list all data which are necessary for simulation and will state the status of those in the Gaiselberg Field.

The following data sets are necessary:

- Geological model
- PVT data
- SCAL data
- Production data
- Pressure data

2.2.1 Geological Model

After several discussions with geologists and geophysicists it turned out that the existing model of Gaiselberg is insufficient for simulation purposes. Especially in 2005 when the wells GA-082B and GA-084A were drilled, discrepancies between the expected and the drilled geology were found, mainly because of two reasons:[8],[9]

- seismic resolution
- fault interpretation

Due to the complexity of the Gaiselberg Field the present seismic vertical and horizontal resolution of about 10 meters is by far too less[8].

'Due to discussions with structural geologist and with state-of-the-art knowledge of fault geometries, gained from analogue models and field studies […] the existing model cannot reproduce the real fault pattern and it cannot predict, which of the faults are sealing and which not. The timeframe for updating the fault pattern of the existing model might easily excess ½ man-year, not taking stratigraphic re-interpretations into account, which might boost the time necessary.' [8],[9]

Figure 2.3 shows the horizon Sarmat 16/1 of the existing geological model. The red lines represent interpreted faults. Green colors represent seismic attributes, which indicate discontinuities in seismic data – in other words: possible faults. The dotted black lines represent a new approach[9]. The significant differences highlight the structural uncertainty caused by limited seismic resolution.

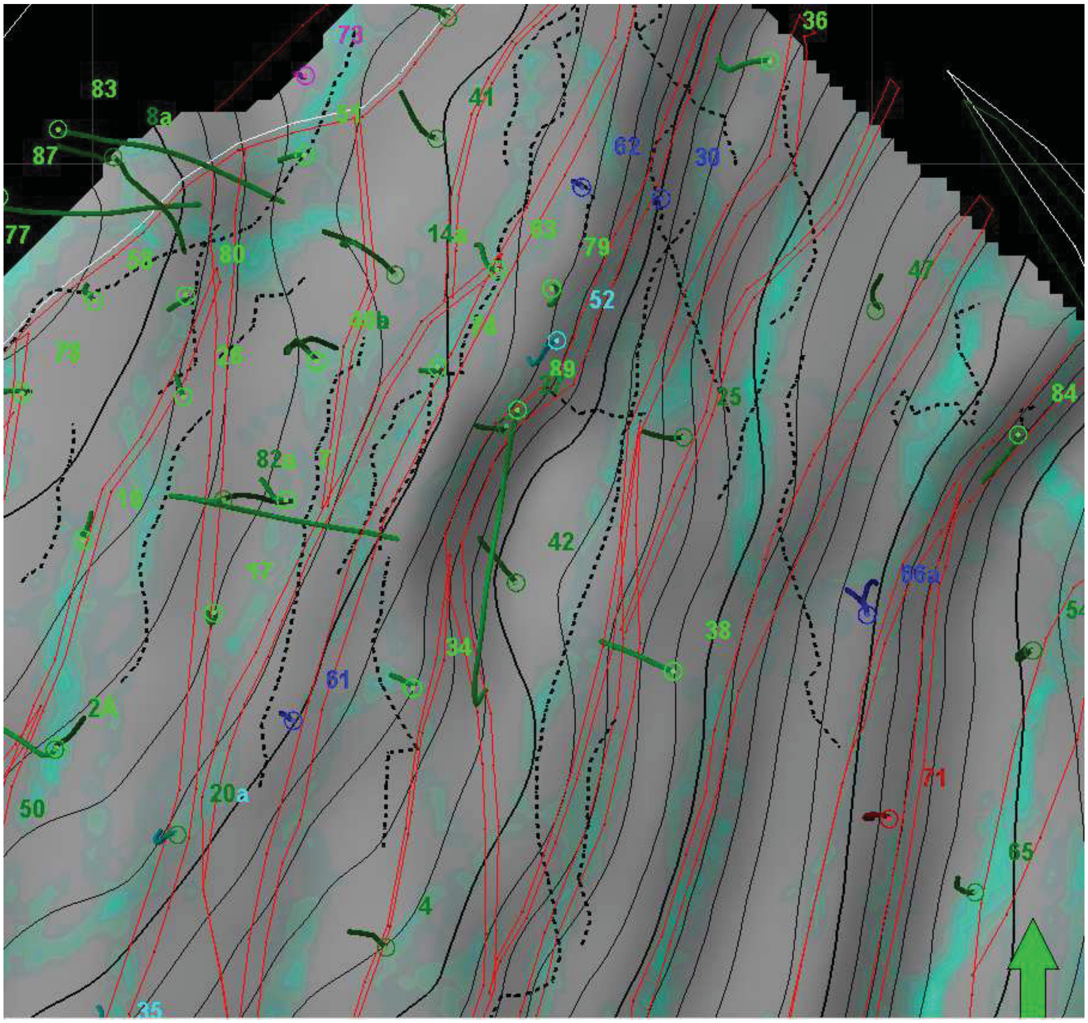


Fig.2.3: Seismic attribute data plotted over the existing map [9]

2.2.2 PVT data

The following PVT data are necessary to run a simulation:

- Reservoir temperature
- Initial pressure

2.2.2.1 Oil properties

- Bubble point pressure
- Stock tank oil gravity
- GOR
- Formation volume factor at different conditions
- Oil compressibility

- Oil density at different conditions
- Oil viscosity at different conditions

2.2.2.2 Water properties

- Salinity
- Temperature
- Viscosity
- Compressibility
- Formation volume factor
- Density at different conditions

2.2.2.3 Dry gas properties (using Z-factors)

Z-factors are plotted against the pressure. Additionally the viscosity of the gas must be known.

2.2.2.4 Live oil properties

The solution gas ratio, the formation volume factor and the viscosity is plotted against the pressure

All oil properties were recorded in the Gaiselberg Field in the past, but only rare data about gas properties are available. Non of the data are available electronically.

2.2.3 SCAL data

In the SCAL section the relative permeability and capillary pressure data are stated.

Relative permeability and capillary pressure curves are available in a non electronically form.

2.2.4 Production data

Basically, all production data for the last 69 years are available. Due to the fact that in some wells more than one layer is perforated, allocation of the volumes to different layers is necessary. For that reason the Reservoir Engineering Department developed allocation factors for each well, to make an allocation to the different horizons and layers possible.

2.2.5 Pressure data

In the beginning of the field life well tests were done – in the last 15 years only rare tests were performed and are not available electronically.

2.3 Summary

Data	Data-frequency	Comment
Geological Model	available	low seismic resolution; uncertainties about fault interpretation
PVT data		
Oil properties (past)	periodical	not electronically available
Oil properties (today)	very rare	not electronically available
Water properties (past)	periodical	not electronically available
Water properties (today)	very rare	not electronically available
Gas properties	very rare	not electronically available
SCAL data	available	not electronically available
Production data	monthly	
Pressure data		
Pressure data (past)	periodical	not electronically available
Pressure data (today)	very rare	

2.4 Conclusions

With the current status of data a simulation of the Gaiselberg Field is not possible. First and foremost the large uncertainties of the geological model make an accurate simulation impossible. Furthermore, an enormous effort will be necessary to history match the model, because of missing pressure data.

Much effort has to be put into the geological model to reinterpret it but even then pressure data are missing which makes the simulation arguable.

3. Production Data

3.1 Injection and Production data

Production and injection data can be used to identify inter-well connectivity between producers and injectors in a very cost effective way. To identify inter-well connectivity injection rate plots are put next to production rate plots. The engineer then looks for corresponding patterns of rate changes. It can be assumed that production rates that rise and/or fall instantly with injection rates changes are directly connected to the injector. In some cases it is even necessary to shift the plots to account for delayed inter-well communications.[10]

3.1.1 Applicability to the Gaiselberg Field

The analysis of the injection and production plots was no success. Trends were not too obvious. This can be explained with the complexity of the field which results basically from multilayer horizons with a very high fault density (chapter 1.2) which can favor an increased dispensation of the injected water. Another fact which contributes to this result is the low data quality of the injection rates.[10]

3.2 Monitoring Water-Flood Operations – Diagnostic Plots

Not only the monitoring of the whole water-flooding project is important but also the monitoring of each individual well to guarantee a successful oil recovery.

The reservoir can only be accessed through individual wells in other words it can be said that the performance of an entire oil field sums up from the performance of each and single well.

Therefore, it is important to have tools available to monitor and assess the wells, which are additionally cost effective.

Traditional well tests interrupt the field operations and their analyses represent relative short time interval – in comparison with the time of fluid injection and production.

On one hand side, unless there is a direct connection between the injector and the producer, the injection of water results in an ever-changing of reservoir conditions. On the other hand side, those changing conditions are nearly impossible to record with the short observation period of a transient well test.[11]

3.2.1 Hall Plot

The Hall Plot is an alternative to transient well tests and is basically very simple. The time-integral of the difference between the injection and the reservoir pressure is plotted against the cumulative injection volumes. Due to integration short-time fluctuations are automatically filtered out. The slope of the Hall Plot is representing the injectivity of the well.

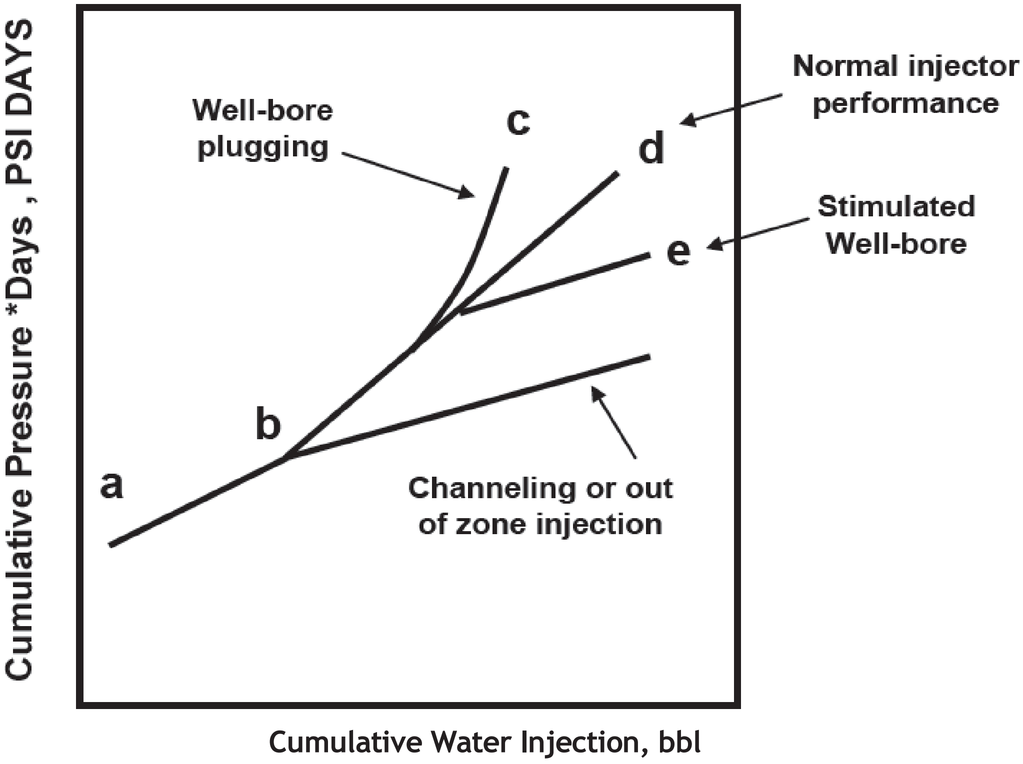


Fig.3.1: Typical plot for a water injector [11]

The big advantage of the Hall Plot is that only injection rates, which are regularly collected, are needed to create the plot. Normal conditions would result in a straight line, whereas a slope change will indicate the change of injection conditions. This slope analysis has already been used to assess well treatments.[12], [13]

It is important to note at this point that the simplicity of Hall's method can be deceiving. It was found, '….a correct Hall plot interpretation requires information about the reservoir pressure at the distance equal to the mean influence radius of the well. If Hall's method is applied without a priori knowledge of the effective ambient pressure, then the conclusions that a kink in the plot is an indication of changes in the well injectivity can be wrong.' [11] Therefore no estimation of the reservoir transmissivity can be made unless the radius of influence is known or doesn't change with time. 'Neither the reservoir pressure at the boundary nor the influence domain size is available from measurements. Lacking other evidence it is reasonable to assume that well treatment or variable well conditions affect the influence radius'. For that reason the slope analysis was developed – for further details see Reference [11].

3.2.1.1 Theoretical Background

The principle of Hall is based on a steady state injection of a well and is based on the radial flow model:[14]

$$p_w = p_e + \frac{\mu}{2\pi k H} \cdot \ln \cdot \frac{r_e}{r_w} \cdot Q \qquad \text{Eq.1}$$

Whereas:

$p_w =$ wellbore pressure

$p_e =$ reservoir pressure

$Q =$ flow rate

$k =$ formation permeability

$H =$ reservoir thickness

$r_e =$ radius of the influenced zone, the influenced zone near the wellbore where the fluid pressure changes due to injection. In this model this zone is considered as circular.

$r_w =$ effective wellbore radius, to account for a skin in the near wellbore region - an effective wellbore radius is assumed. The ratio r_e/r_w is between the wellbore radius and the radius of influence.

In this model the compressibility of the fluids is neglected, hence the formation factor, which would be written in front of Q, becomes one.
If the pattern is not exactly radial, the pressure can be averaged to account for that.[14]
It is also important to keep in mind that Equation 1 is based on a model and hence based on assumptions:

- the fluid is homogenous and incompressible
- the reservoir is vertically confined and uniform, with respect to permeability and thickness
- the reservoir is homogeneous, isotropic and horizontal

- gravity doesn't play a role
- the pressure at re doesn't change (steady state condition)

If those assumptions hold true, the flow is radial. As a matter of fact in real life those assumptions are not fulfilled – the injector is perforated in multiple layers with different permeabilities and thicknesses, flow is disturbed by heterogenities, interferences between wells can occur and fractures can be present - although the model gives an adequately approximation. The parameter, or its inverse,

$$b = \frac{\mu}{2\pi k H} \cdot \ln \cdot \frac{r_e}{r_w} \qquad \text{Eq.2}$$

is often used for the assessment of the well performance. If rates and pressures are constant over time b, can also be written as:

$$b = \frac{Q}{p_w - p_e} \qquad \text{Eq.3}$$

$b =$ is then the inverse of the specific well injectivity[15]. Equation 3 can not be used if there are any fluctuations in rate or pressure.

Equation 1 can be integrated with respect to time:

$$\int_{t_0}^{t} (p_w - p_e) \cdot d\tau = \int_{t_0}^{t} \left(\frac{\mu}{2\pi k H} \cdot \ln \cdot \frac{r_e}{r_w} \cdot Q \right) d\tau \qquad \text{Eq.4}$$

It is important to note that the upper limit of the integral is variable. As already mentioned, as t increases, short-time fluctuations are filtered out leading to a more robust procedure for the assessment using the parameter b.

$$\Pi(t) = \int_{t_0}^{t} p_w(\tau) d\tau \qquad and \qquad V(t) = \int_{t_0}^{t} Q(\tau) d\tau \qquad \text{Eq.5 and Eq.6}$$

The Hall Plot, plots the right side of Equation 4 against the left side of Equation 4. Due to the fact that b is constant it can be written in front of the integral, furthermore if the pressure p_e, doesn't change, the plot will result in a straight line whose slope is equal to b. If the objective is to assess a well treatment, the change of slope must be observed. However, p_e must be known, to avoid a misinterpretation of the graph.

An example should illustrate this effect: Figure 3.2 represents a Hall Plot for given reservoir parameters and injection data. For a constant reservoir pressure of 1400psi (red cross) the Hall Plot results in a straight line. In the other two graphs the estimate of the reservoir pressure is incorrect - even with constant injection rates the plot will show a kink. The magnitude of the kink depends on the difference between the exact and estimated reservoir pressure. The Hall Plot will only result in a straight line if the reservoir properties and the reservoir pressure are constant and if $p=p_i$. For that reason, the slope analysis was developed.[11]

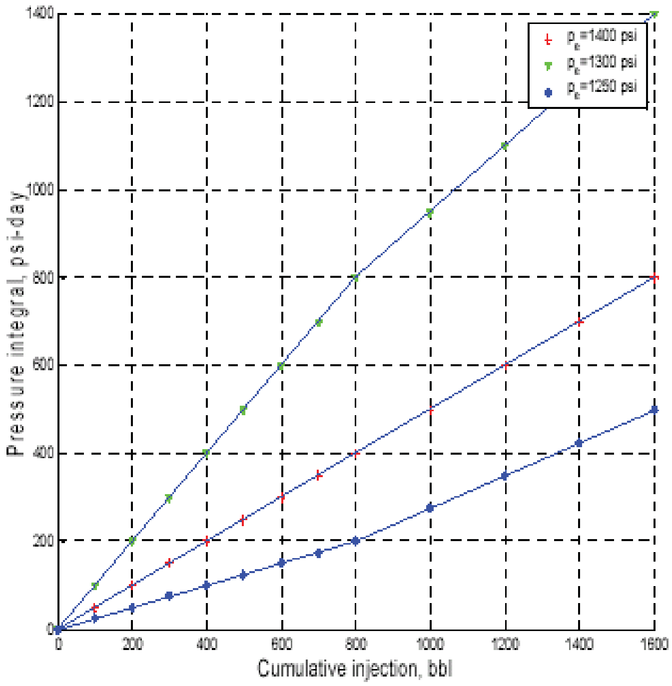


Fig.3.2: Hall plot at constant formation properties, assuming different reservoir pressures (pe= 1300 psi = correct reservoir pressure) [11]

3.2.1.2 Conclusions

Advantages:

- The Hall plot is a continuing monitoring method – it can help to identify changes of the injection conditions over an extended period of time.
- The Hall integral has a smoothing effect on the data
- Data acquisition is inexpensive because only the cumulative injection volume and the surface pressure is needed

Disadvantages:

- Skin and transmissibility are included in the slope – it is just possible to calculate one if the other is known – periodical well tests are still necessary to determine the skin and transmissibility.
- If p_e is not known, a kink in the graph can be misinterpreted

3.2.1.3 Applicability to the Gaiselberg Field

Due to the fact that no well head pressures of the injection wells were recorded in the past five years it is not possible to create Hall plots for that time frame. For the time before only punctiform records were done and are not available electronically. Recently, new manometers were installed at the injection wells so that it is possible to record the pressure from now on.

Another important aspect is the injection rate. Several injectors are provided with water through a star-shaped piping. Only the total cumulative volume is measured on a daily basis. With the help of a mobile flow-meter every year an allocation factor is calculated to distribute the daily cumulative volume to the injectors. This circumstance will not allow creating a reliable Hall plot.

3.2 WOR – Plot

The WOR plot is a technique which can be used to determine excessive water or gas production mechanism. With the help of numerical simulation it was found out that log-log plots of WOR vs. time or GOR vs. time look different for different mechanisms. In general three basic classifications exist for the problem:

- Water or gas coning, multilayer
- channeling (high permeable layer breakthrough) and
- near wellbore channeling.

Chan[16] developed a methodology which can be used to quickly diagnose the mechanisms. It uses the following data:[16]

- Production history of the entire period of water flood
- WOR and its derivates
- Cumulative oil produced or recovery efficiency
- Oil and gas rate declines

The plot can mainly be used to evaluate the remaining production potential of the well and for selection of water control treatment candidates. Furthermore the plots can be used to evaluate the effectiveness of a water flood in that way that possible injector/producer pairs are found where the injected water does not sweep oil any more. In that case a tracer test would give unambiguous information.

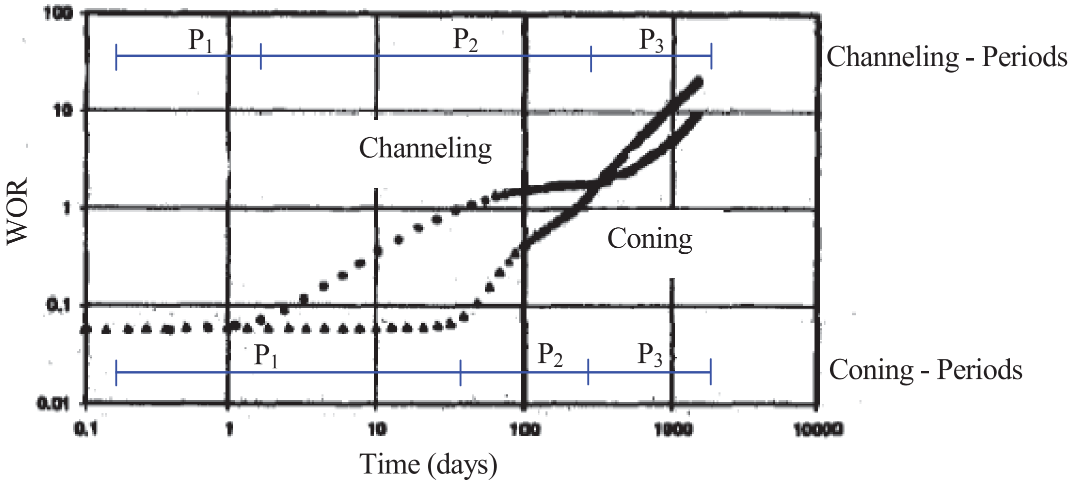


Fig.3.3: Water coning and channeling – WOR comparison [16]

Fig. 3.3 shows the clear differences between water coning and multilayer channeling in the WOR plot. This plot is the result of numerical simulation using a black oil simulator. The set of PVT, saturation function data, permeability and porosity distribution, initial conditions are kept the same. The only difference is the flow geometry. In case of coning, the WOC was defined and a bottom water influx was simulated by constant bottom pressure which was realized by water injection only into the edge of the bottom layer. Only the top 20% of the layer were perforated. In case of channeling the bottom layer was eliminated. Water was injected with constant pressure into all layers at the edge – all layers were perforated.

If one has a closer look on Fig. 3.3, three periods of WOR development can be seen. In the early time period it can be seen that the WOR curve remains constant showing initial production. The initial WOR depends on the initial water saturation and its distribution among all layers as well as on relative permeability functions. The end is indicated by a significant increase in WOR. The length of this period depends on the water drive mechanisms.[16]

For coning the first period is significant shorter. This fact has several factors, like vertical to horizontal permeability ratio, bottom water influx, production pressure drawdown and relative permeability functions, but predominantly the distance between the OWC and the nearest perforation interval. Physically, the end of this period is when the bottom water cone has reached the bottom perforation interval.[16]

For channeling the departure time is greatly influenced by the well spacing – other factors can be: injection rate, producer drawdown pressure, initial water saturation and distribution and relative permeability functions. Physically, the end of this period, in case of channeling, is when the water breaks through at one layer in a multilayered reservoir.[16]

In the second period of time it can be seen that the WOR increases with time. The rate of increase depends on the mechanism. In case of coning the WOR increases relatively slowly and gets constant at the end of this period. In this period of time the cone not only grows vertically upwards towards the uppermost perforation but also expends radially.

In case of channeling the WOR increases drastically with time. This can be explained by the fact that water production drastically increases as soon as the water breaks through in one of the layers. The slope also depends on the relative permeability functions and initial saturation functions. At the end of this period the WOR values tend to get constant which indicates the production depletion of the first breakthrough layer. This transition period is again followed by an increase of the WOR values which then is the water breakthrough of the second layer. The duration of the transition period depends on the layer permeability contrast.[16]

The third period in the case of coning indicates the existence of a pseudo steady state cone – the well mainly produces bottom water. The water cone can be seen as a high conductive channel – the WOR increase becomes drastical which is an indication for the start of this period.

In the case of channeling the rate of increase is nearly the same as before the transition period. All channeling WOR slopes are very close to each other due to the fact that they mainly depend on the relative permeability functions.[16]

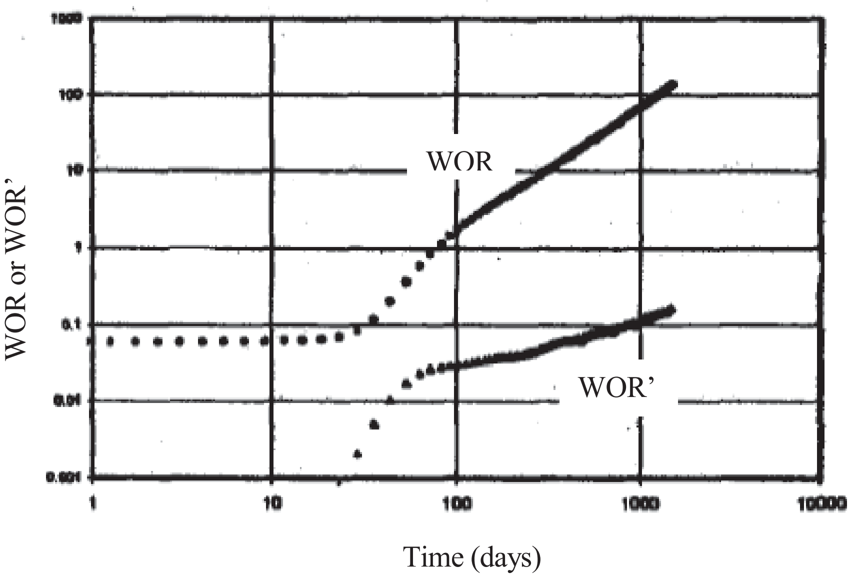


Fig.3.4: Multilayer channeling WOR and WOR' derivates [16]

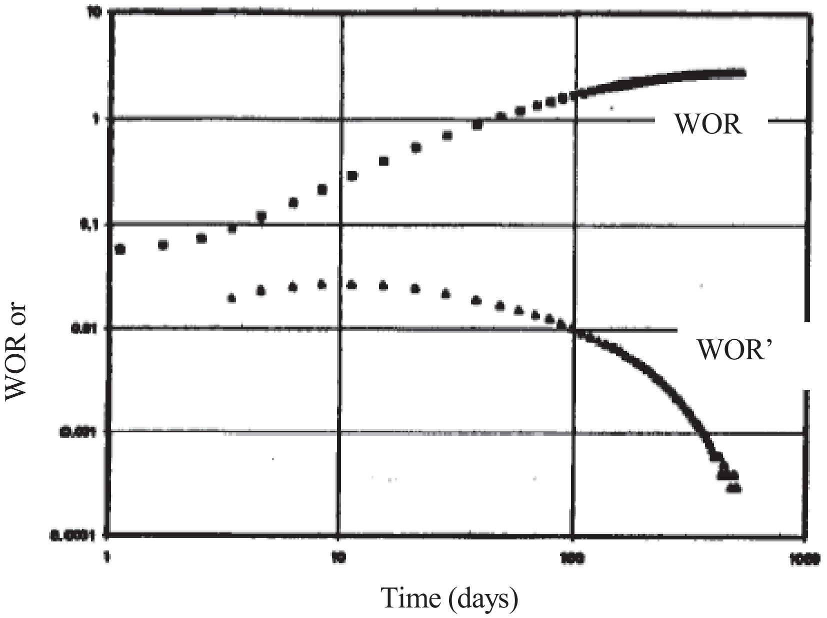


Fig.3.5: Bottomwater coning WOR and WOR' derivates [16]

Further studies showed that also the time derivates of the WOR can be used to distinguish between the different mechanisms. Figure 3.4 and 3.5 show the WOR and WOR derivates for channeling and coning. The WOR' (simply the derivate of the WOR) shows a constant behavior in the beginning for channeling and a negative slope for coning. The behavior for channeling in the third period is shown in figure 4.

The WOR derivate plot becomes very useful to distinguish between the different mechanisms especially when limited production data are available.

3.2.1 Applicability to the Gaiselberg Field

The review of the WOR plots of the Gaiselberg gave no results. For the Gaiselberg Field only the monthly oil, gas and water production per well is available – no daily production is available. It seems to be that this average value of a month does not allow a precise interpretation of those plots.

4. Material Balance

This chapter will describe in more detail the technique of Voidage Replacement (VR) and Voidage Replacement Ratio (VRR) which are based on the material-balance principle. The technique can easily be understood with the liquid tank analogy (Fig.4.1). The production of oil, water and gas causes a generation of a void and hence a pressure-drop in the reservoir. Water injection should fill this void.[1]

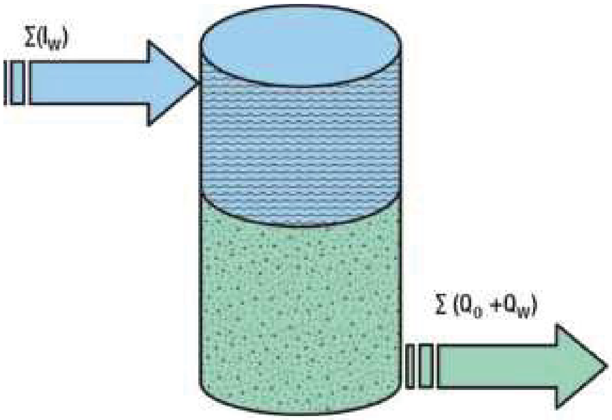


Fig.4.1: Tank model [1]

VR and VRR are some important tools in surveillance and monitoring. The replacement of the generated void is not only to get rid of the produced water but also to increase the performance and recovery.
The analysis of VR and VRR plots make the reservoir response, the volumetric sweep and the pattern performance descriptive.[1]

The application of VR and especially the analyses of the results can point the reservoir response. It can also be used for troubleshooting or to identify problems like channeling or thief zones, fingering, fracture communications, etc.[1]

4.2 VRR Analysis

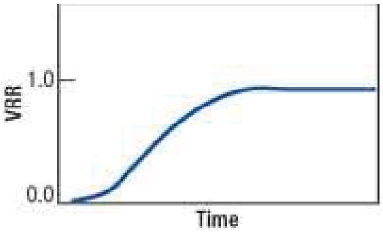


Fig.4.2: VRR vs. time plot [1]

In most cases the VRR is plotted against time. Fig. 4.2 shows an ideal VRR vs. time plot. It can be seen that if injection continues and hence the reservoir is filled up the curve gradually approaches unity. It is important to note that depending on the parameters chosen the estimate of VRR can vary.

In case the injection starts at initial conditions, VRR can go beyond unity, although the reservoir has not been repressurized yet.

If the bubble point pressure is the initial pressure, it can take a long time until the VRR values become constant.

The cumulative VRR analysis, as it is with all material balance or volumetric calculations, greatly depends on the data available, which restricts the use to middle and late advanced water-floods.[1]

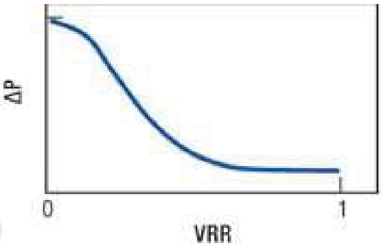


Fig.4.3: VRR vs. ΔP plot [1]

This plot helps to understand the effect of pressure on VRR. It is also a very effective tool to identify the loss of water to thief zones or the aquifer.

Production forces the pressure to decline, but the injection of water will either make the value of Δp smaller or will approach zero when the reservoir is repressurized to its initial pressure. If the difference between the original and the present pressure approaches zero, the VRR value approaches asymptotically zero. If the cumulative VR does not force the Δp to decrease and the present VRR is showing VR close to unity, it can be the case that the injected water is siphoned into an other layer through a thief zone or channeled into a different layer.[1]

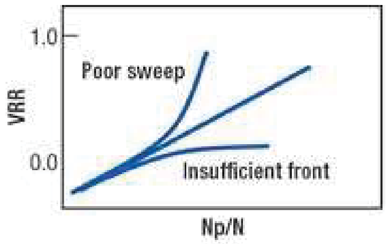


Fig. 4.4: VRR vs. Np/N [1]

This plot (Fig.4.4) gives an understanding from the sweep efficiency side of the waterflood. A good water-flood displacing of the reservoir fluids and a sufficient number of producers to recover the displaced fluids is indicated by a linear relationship between VRR and Np/N. In other words: every unit produced fluids is pushed by a unit of injected water. However, the real situations depart from the idealized one in the way that they describe a curve. If it is observed that the curve tends towards the x-axis (VRR), the water injection does not support production, which can be caused by:[1]

- no stable front
- poor reservoir sweep
- thief zones
- the aquifer takes the injected water

On the other hand, if the curve tends towards the y-axis (Np/N) the injected is not enough to yield results, but the reservoir is producing with the help of natural drives.[1]

4.3 VRR Situations

The formation volume factor used for the calculations is related to a reference pressure. This fact makes the calculation of VRR subjective – an example: if the reference pressure was taken at initial conditions and the water-flooding project was started much below the initial pressure, the volumetric situation will change even if the VRR is constant. Other possible conditions:[1]

- although the present VRR is constant, the cumulative or reservoir wide VR is far away from unity. Although the cumulative VR should reflect the whole reservoir repressurization, it may not be the case.
- VRR is based on the assumption that the reservoir is homogeneous. A heterogeneous reservoir can cause the VR to be more or less than unity at some places.
- Injector and producer distribution can cause deflections in the real-time VR
- If an aquifer is present, the injected water can be lost to it and hence misrepresent the VR.

Factors which affect the flow in porous media like porosity, permeability, heterogeneity, fluid properties and geological complexity will also influence the VR process.[1]

Appendix A gives a detailed description of the mathematical derivation of the VRR-Method.

4.4 Conclusions

Although, VRR is an easy-to-use technique, it is a very effective tool to control and monitor a water-flood project. It can be used either for pressure maintenance or for water-flooding purposes.

The calculations greatly depend on the conditions when the water-flooding process was started.
It can greatly help to assess the success of the water-flood but the pitfalls of the technique should always be kept in mind.[1]

4.5 Applicability to the Gaiselberg Field

Basically this technique can not be used in the Gaiselberg Field mainly because of the following reason:

- Lack of data: very rare data about pressures, FVFs, compressibility, accurate injection rates and solution gas ratios were recorded in the past.

Furthermore, it can be assumed that the geological complexity of the Gaiselberg Field would greatly influence the VRR calculations

5. Salinity

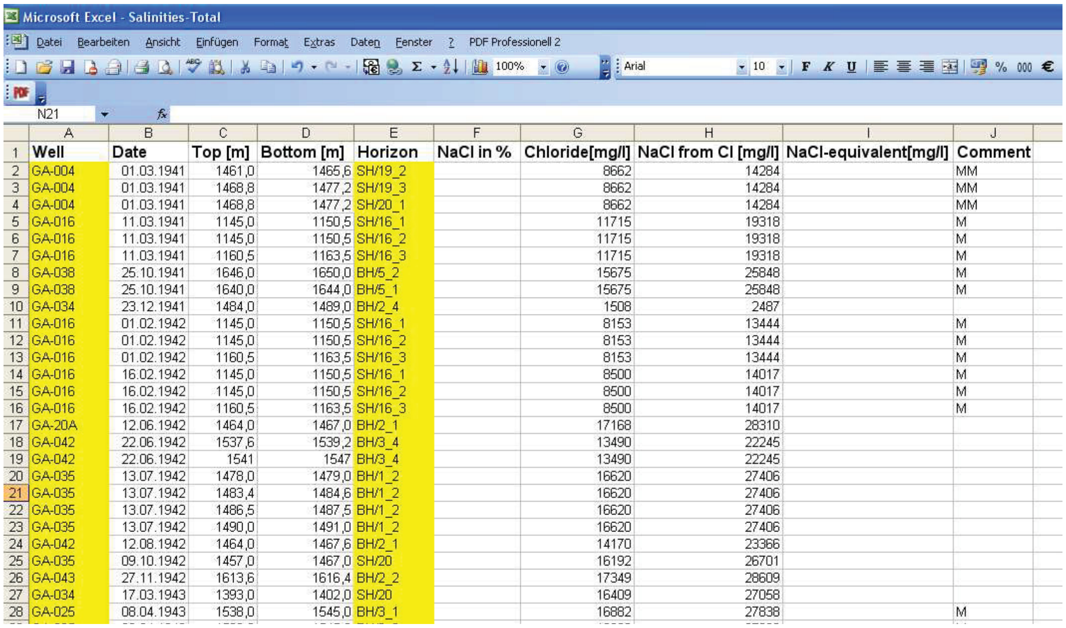
5.1 Introduction

When a Tracer was pondered to characterize the flood-profile the idea came up to use existing data material first. For this reason a survey on basis of the different water salinities was done to asses the influence of the injectors.

This chapter presents the approach and the results of this survey but also doesn't conceal the problems encountered; moreover suggestions for improvements for future surveys are stated.

5.2 Data

No data-base with salinity measurements has been available until now. Insistent investigation was necessary to find salinity data because of the different deposition places. None of the data were available electronically which demanded the digitalization of them. Due to simplicity reasons this step was performed in 'Microsoft Excel'. The creation of a data base will be discussed later on. The following screen shot gives an overlook about the structure of the spread sheet:



	A	B	C	D	E	F	G	H	I	J
1	Well	Date	Top [m]	Bottom [m]	Horizon	NaCl in %	Chloride[mg/l]	NaCl from Cl [mg/l]	NaCl-equivalent[mg/l]	Comment
2	GA-004	01.03.1941	1461,0	1465,6	SH/19_2		8662	14284		MM
3	GA-004	01.03.1941	1468,8	1477,2	SH/19_3		8662	14284		MM
4	GA-004	01.03.1941	1468,8	1477,2	SH/20_1		8662	14284		MM
5	GA-016	11.03.1941	1145,0	1150,5	SH/16_1		11715	19318		M
6	GA-016	11.03.1941	1145,0	1150,5	SH/16_2		11715	19318		M
7	GA-016	11.03.1941	1160,5	1163,5	SH/16_3		11715	19318		M
8	GA-038	25.10.1941	1646,0	1650,0	BH/5_2		15675	25848		M
9	GA-038	25.10.1941	1640,0	1644,0	BH/5_1		15675	25848		M
10	GA-034	23.12.1941	1484,0	1489,0	BH/2_4		1508	2487		
11	GA-016	01.02.1942	1145,0	1150,5	SH/16_1		8153	13444		M
12	GA-016	01.02.1942	1145,0	1150,5	SH/16_2		8153	13444		M
13	GA-016	01.02.1942	1160,5	1163,5	SH/16_3		8153	13444		M
14	GA-016	16.02.1942	1145,0	1150,5	SH/16_1		8500	14017		M
15	GA-016	16.02.1942	1145,0	1150,5	SH/16_2		8500	14017		M
16	GA-016	16.02.1942	1160,5	1163,5	SH/16_3		8500	14017		M
17	GA-20A	12.06.1942	1464,0	1467,0	BH/2_1		17168	28310		
18	GA-042	22.06.1942	1537,6	1539,2	BH/3_4		13490	22245		
19	GA-042	22.06.1942	1541	1547	BH/3_4		13490	22245		
20	GA-035	13.07.1942	1478,0	1479,0	BH/1_2		16620	27406		
21	GA-035	13.07.1942	1483,4	1484,6	BH/1_2		16620	27406		
22	GA-035	13.07.1942	1486,5	1487,5	BH/1_2		16620	27406		
23	GA-035	13.07.1942	1490,0	1491,0	BH/1_2		16620	27406		
24	GA-042	12.08.1942	1464,0	1467,6	BH/2_1		14170	23366		
25	GA-035	09.10.1942	1457,0	1467,0	SH/20		16192	26701		
26	GA-043	27.11.1942	1613,6	1616,4	BH/2_2		17349	28609		
27	GA-034	17.03.1943	1393,0	1402,0	SH/20		16409	27058		
28	GA-025	08.04.1943	1538,0	1545,0	BH/3_1		16882	27838		M

Fig.5.1: Salinity spread-sheet in 'Microsoft Excel'

The following data were evaluated:

- Well: The name of the well where the sample was taken. The experience shows that engineers often create their own nomenclature which makes it difficult to combine data later on. For that reason the UWI (unify well index) is always used.

- Date: The date when the sample was taken.

- Top, Bottom: indicate the perforation depths from which the sample was taken.

- Horizon: The associated horizon, stated on the laboratory report relates always to the geological interpretation at the time when the sample was taken. Due to this fact the horizons were not evaluated from the laboratory report but from the newest geological interpretation available. It is important to state that in case of multiple layer perforation each and every single layer has its own line in the spread sheet. Naturally all other data of the sample are the same in all the lines. For simplicity reasons even the perforation interval was kept the same. In other words: A sample has as much lines as perforated layers. This was done to enable a filtering after a certain horizon.

- NaCl in %: This value multiplied with 10.000 equals the NaCl concentration in mg/l

- Chloride: The mass-concentration of chloride ions in the sample.

- NaCl from Cl: Basically only the chloride concentration is measured. The NaCl-concentration is not measured but calculated from the chloride concentration

- NaCl-equivalent: The conductance of the dilution was used in the analysis to determine the NaCl concentration.

- Comment: Some wells are perforated in more than one layers or even in more horizons. Samples taken from these wells represent a mixture of formation waters from different layers and thus also a mixture of their salinities. To annotate that fact the column ‘Comment’ was created. If nothing is stated in this cell, the salinity was only taken from one layer. An ‘M’ indicates that the sample represents a mixture of formation waters from different layers within a horizon. A Double ‘M’ indicates that the water-sample was even taken from different horizons. Even if the spread sheet is filtered after a certain horizon, it is still possible to judge the quality of the sample.

As stated above only the mass-concentration of the chloride ions is measured. All other values are then calculated. The Cl value is just multiplied with the atom ratio of the two components.

$$NaCl[mg/l] = Cl[mg/l] \cdot \frac{22{,}989 g/mol(Na) + 35{,}452 g/mol(Cl)}{35{,}452 g/mol(Cl)}$$

In previous years water samples were analyzed by the RAG-Laboratory. This Laboratory was closed in 1971, therefore just a small laboratory in the field is doing the salinity measurements nowadays. If still a 'complete-analysis' of the formation water is necessary, it is done by the OMV Exploration and Production laboratory in Gerasdorf near Vienna. Such a 'complete-analysis' for all production wells in the Gaiselberg Field was performed within the scope of this thesis to get present salinity measurements.
Laboratory reports always state the mass-concentration of the chloride ions or the NaCl-equivalent. In field-measurements the report always states the NaCl in %. For this reason not all columns are filled out. For analysis reasons all different values were then transformed to 'NaCl from Cl'(see above).

The evaluation shows that no salinity measurements were performed from 1973 till 1989.

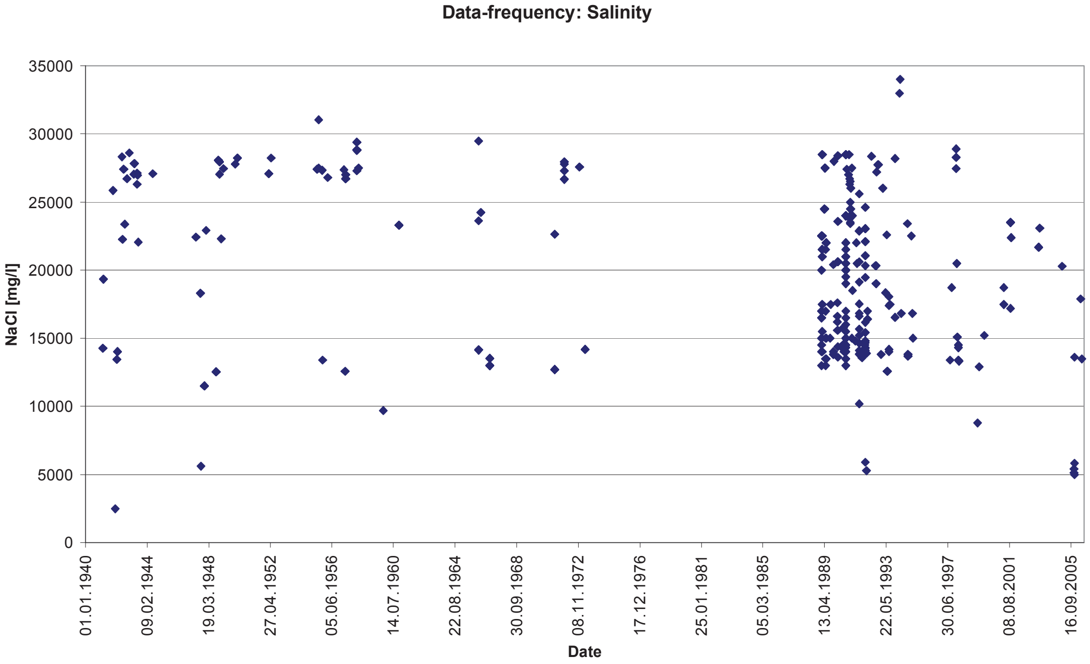


Fig.5.2: Data-frequency salinity

Yellow underlayed cells (Fig. 5.1) indicate that the measurement was performed in a laboratory. This evaluation was necessary because of data-quality between the different measurement methods:

5.2.1 Measurement Methods

Two different methods of salinity measurement are performed:

- Analytic determination according to 'Mohr'
    - Field of application

The procedure is suitable for the direct determination of chloride ions within the measurement range of concentration from 10 mg/l to 150 mg/l.

The measurement range can be extended by suitable dilution or by use of a silver nitrate dilution of higher concentration.

Because of the various disturbances the application of this procedure is limited to relatively clean waters.[43]

- Basis of the procedure

Chloride ions react with silver ions to hardly soluble silver chloride.

$$Cl^- + Ag^+ \rightarrow AgCl \downarrow$$

After reaching a marginal surplus, more silver-ions form with chromate ions a red-brown silver-chromate.[43]

- Potentiometric determination
    - Field of application

This method is suitable for the direct determination of chloride ions within the concentration range of 7 mg/l to 140 mg/l. The measurement range can be extended by suitable dilution or by use of silver nitrate solution of higher concentration. It is also applicably to colored and clouded water. Especially oilfield waters are very often embittered.[43]

- Basis of the procedure

The chloride ions are titrated with silver-ions.

For determining the end-point, one follows the voltage between a reference electrode on the one hand, and a silver electrode or a chloride-ion-selective electrode on the other hand. The voltage depends on the logarithm of the chloride ions activity. If one applies this voltage in mV on the ordinate and the silver nitrate solution in ml on the abscissa, the inflection point, corresponds to the equivalence-point.[43]

5.2.1.3 Accuracy of measurement

- Mohr

The determination according to 'Mohr' is used in the field laboratory and is based on titration. The point, when the color of the solution changes, is determined by the human eye.

Different people judge differently hence this method is not very accurate.

To see how different users judge, the author decided to do an experiment. Three workers were asked to analyze the same formation water. The workers did not know that all of them analyzed the same sample. The outcome:

Worker A: 8726 mg/l
Worker B: 9697 mg/l
Worker C: 9162 mg/l

It can be seen that the results differ up to 971 mg/l among each other.

Considering the average water-flood salinity this difference would lead to an possible error of about 5%.

This fact is especially important in the definition of 'salinity classes' in chapter 5.4.2.1.

- Potentiometric

In the potentiometric determination the 'inflection point' indicates this point, which can be determined automatically and therefore much more precisely.

5.3 Initial Salinities

The initial salinities were assayed to identify contingent salinity distribution of the Gaiselberg Field in its original state. To do so the following working steps were defined:

1. filter the data after time

   The data-sample is limited to data before 1970 to avoid the influence of the water-flood.

2. divide the obtained data into horizons

   Due to data-frequency reasons the division into layers was waived.

3. delete all data with the comment 'MM'

   Mixed salinities (chapter 5.2) are not representative for a specific horizon.

4. divide the data-sample into surface points (well)

5. areal allocation of the initial salinities

   The areal allocation makes it easier to identify trends in a horizon.

5.3.1 Gained Cognitions – Salinity Trends

After the first two steps were done it was obvious that the data-frequency of the initial salinities is very rare.

5.3.1.1 Areal Trend

The 19th Sarmat shows a relatively constant distribution within the horizon.

For the remaining Sarmat horizons (11, 12, 13, 14, 15, 16, 17, 18 and 20) no statement about the areal distribution is possible due to the lack of data.

5.3.1.2 Vertical Trend

Fig. 5.3 shows that salinity in ppm against the measured depth in m. Salinities greatly vary with depth, and therefore with stratigraphic unit. It can be observed that the water salinity rapidly increases with depth up to values of 25000-30000 ppm at a depth of about 1400m (1200m TVD) were the values tend to get constant and therefore become independent of depth. The fact that present day sea water salinities (25000 ppm) are similar to those salinities of deeper horizons is worth knowing.
In Fig. 5.4 all values are subjected to their stratigraphic unit where they occurred. Two main categories are existing:

- SH/11 – SH/16_4 with about 15000 ppm
- SH/16_5 – BH/12 with about 25000 ppm – 35000 ppm

A reason for that could be the thick shale unit in the middle of the 16th Sarmat which acts as a salinity barrier.[3]

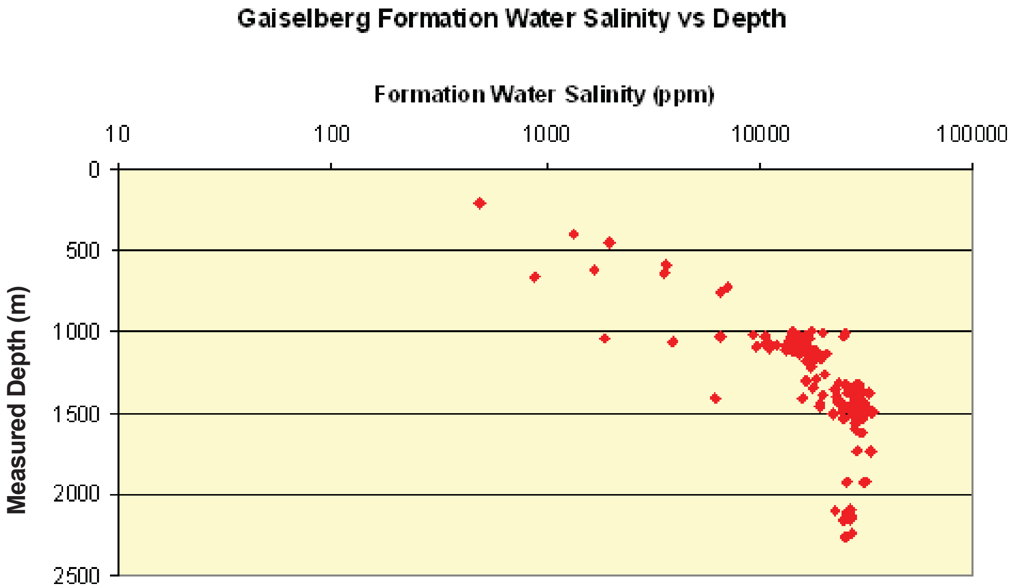


Fig.5.3: Gaiselberg Formation Water Salinity vs. Depth [3]

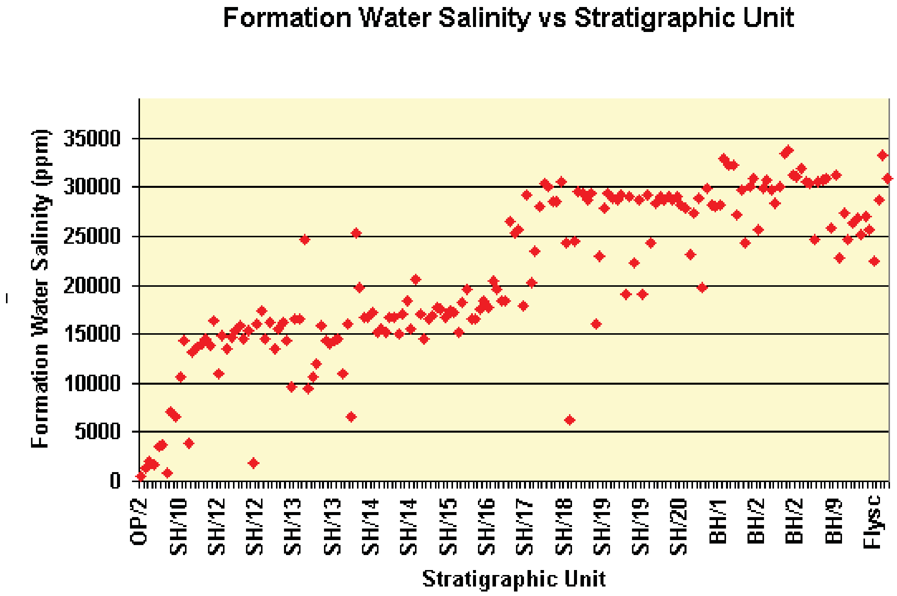


Fig. 5.4: Formation Water vs. Stratigraphic Unit [3]

These two diagrams show that the salinity increases with increasing depth. Figure 5.4 also reflects the fact that within a horizon the distribution of salinity concentration is nearly constant.

5.4 Analysis

5.4.1 Principle of assessment

The idea behind is to use the salinity as a ‘natural’ tracer to find out if a well is influenced or not by the water flood.

The basis for this salinity-survey is the different water salinities of the Gaiselberg Field and the nearly constant flood-water salinity.

Water-flood salinities:

Sampled	NaCl [mg/l]
23.12.1991	18800
06.10.1992	18800
05.01.1999	19400
30.08.2004	18100
03.07.2006	18732
10.07.2006	18400
mean	**18705**
standard deviation	438

Tab.5.1: Water-flood salinities of the Gaiselberg Field

The first approach was to create a map for each horizon where the initial water-salinities are indicated with the help of different colors.

The idea was to compare this map with a map where present salinities are indicated. If a producer would be influenced by the water-flood, the salinity of the producer would tend towards the constant flood-water salinity.

Due to the fact that the data-frequency of the initial salinities is very rare this idea could not be realized.

The second approach was to base the judgment on an individual basis.

Figure 5.5 shows the idealized behavior of a producer.

In early production the original salinity of the produced water stays nearly constant. This indicates that the produced water is only from the aquifer. After the water break through at the injector salinity starts to approach the water flood salinity (WFS). The higher the fraction of the water-flood is, the more the salinity of the produced water approaches the WFS. At point three an extensive flooding already occurred. Depending on the geological situation and reservoir properties between the injector and producer this transition period (between point 2 and 3) can be in high gear or unincisive.

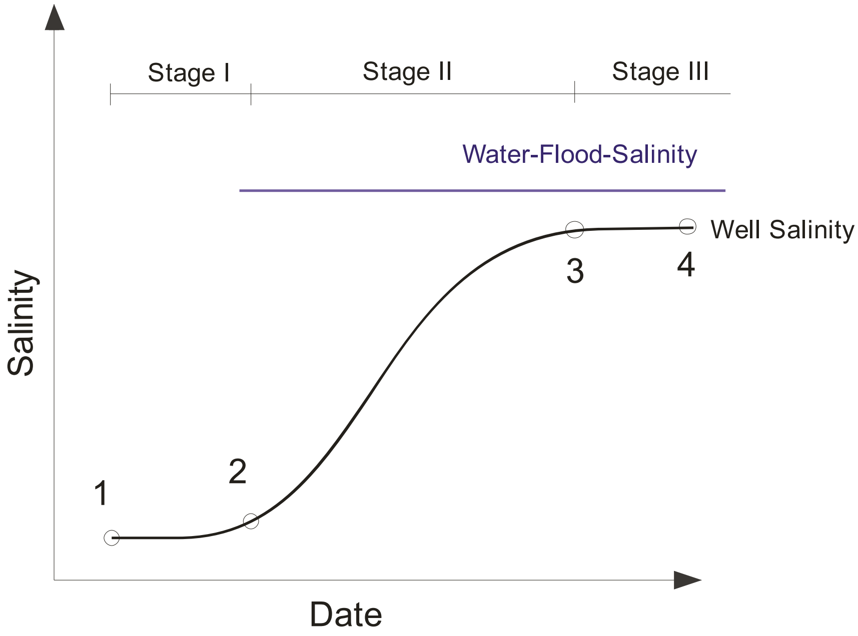


Fig.5.5: Behavior of an idealized influenced producer

Fig. 5.6 shows the behavior of an unaffected producer.

The salinity of the producer even stays constant in times of water-flooding.

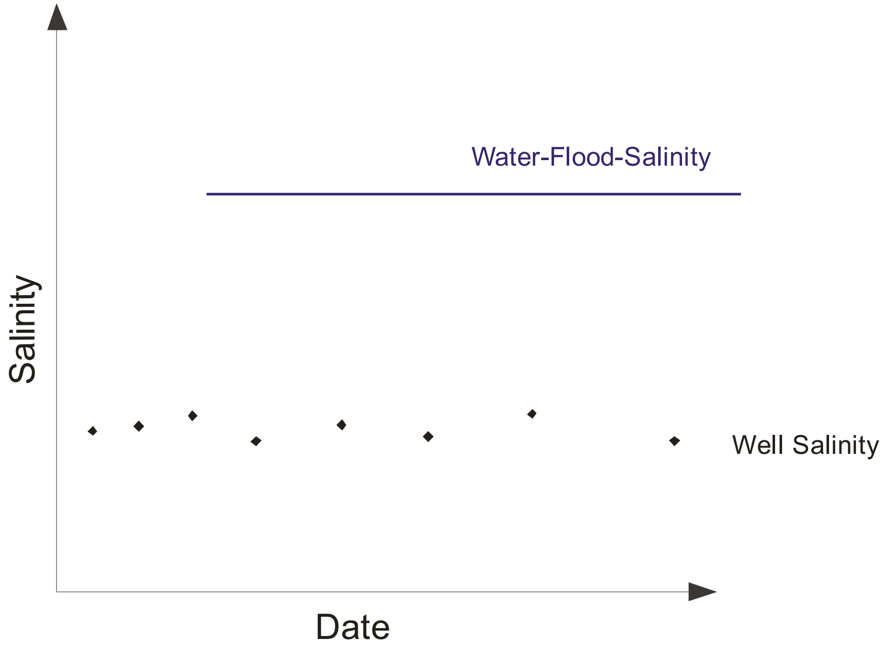


Fig.5.6: Behaviour of an unaffected producer

On basis of those two cases the salinity trends were judged.

It is important to note at this point that this change in salinity could also be caused by other reasons:

- casing leak
  Water from another formation could alter the salinity of the considered horizon

- communication behind the casings
  Poor cementing can cause water of other formations to influence the salinity of a specific horizon.

- faults
  As a result of pressure changes in the reservoir, water can flow along faults into different reservoirs and hence change the salinity.

All the analysis is based on the assumption that the salinity change is caused by the water flood. To evaluate the influence of the reason above it needs more investigation.

5.4.1.1 Working Steps

The following working steps were defined:

1. filter the data after horizon(e.g. 12th Sarmat)
2. delete all data with the comment 'MM'
3. data thus obtained have to be sorted after wells
4. creation of a diagram: salinity versus time

The diagrams always present one well in one specific horizon to avoid the influence of other horizons.

5.4.1.2 Classification

The difference between the mean of the water-flood and the current value (point 4) indicates the grade of flooding. To quantify this difference, six classes were created. The classes are defined as follows:

CLASS	NaCl difference [mg/l]
1	<1000
2	≥1000 - 2000
3	≥2000 - 3000
4	≥3000 - 4000
5	≥4000 - 5000
6	≥5000 - 6000
>6	≥6000

Tab.5.2: Salinity Classes

Class 1 indicates that the produced water is identical (considering the salinities) with that one of the water-flood. An experiment (chapter 5.2.1.3) showed that a relative error between measurements can be up to about 1000 mg/l. For that reason all differences below 1000 mg/l are classified as class 1.

For illustration these classes were, with the help of colors, inscribed into a reservoir map. All results of one 'reservoir-part' are shown in one representative map to maintain an overview. The map was taken from the middle of the part to keep the error as small as possible. For part 1 the map of Sarmat 15/1 and for part 2 the map of Sarmat 19/1 was taken.

In some cases the data frequency is so low that no trend can be encountered, but still a present value is available. Although we don't know if the producer is influenced or not, the difference (between water-flood mean and present value) is still classified. In the map this one-point-judgment is indicated with a red edging.

All cases stated above (influenced, not influenced and one-point data) can also be applied for data sets which have no 'present value'. The reason for that could be low data-frequency or the fact that a well doesn't produce from this horizon any more.
The same judgment process is applied for those data sets. The only difference is that the results are inscribed in different maps.
Figure 5.7 shows the classification process.

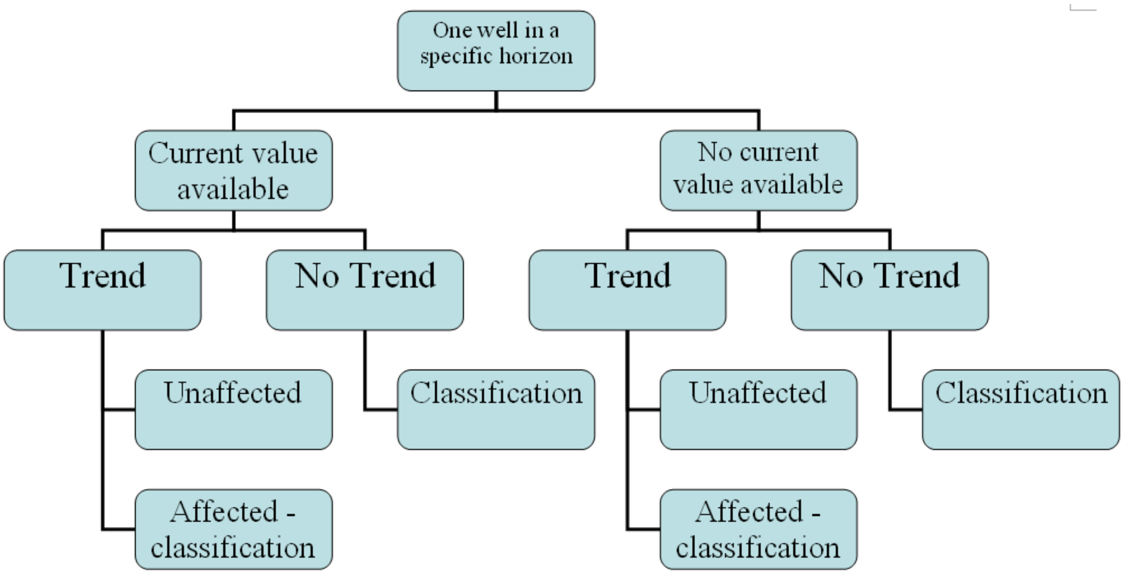


Fig.5.7: Salinity Classification Scheme

- Sidetracks

Some of the sidetracks were only drilled due to fact that the motherbore was inaccessible and therefore stayed in the same formation. Salinity data from those sidetracks were included into the data of the motherbore. Sidetracks which were drilled into a different formation than the motherbore were handled separately.

- Outliers

In some diagrams significant outliers with an extremely high Cl-value are observed. This could be explained with the fact that injectors in the Gaiselberg Field are stimulated

with HCl which will, after the breakthrough to the producer, significantly increase the Cl-value of that producer.
The entire analysis and the corresponding results can be found in Appendix B.

5.5 Results - Conclusions

The salinity map (Fig. 5.9) shows that some wells within a horizon and a compartment have nearly the same salinity as the water-flood; however some wells significantly differ from those of the water-flood salinity. This could be an indication that some of the wells are influenced by the waterflood however some of them not. It could also be an indication for the fact that oil is bypassed.

However it also must be stated that the salinity survey is of limited use because of the very low data frequency in some cases. This especially can be seen in Fig. 5.10 – nearly no statement about 'Part 2' is possible.

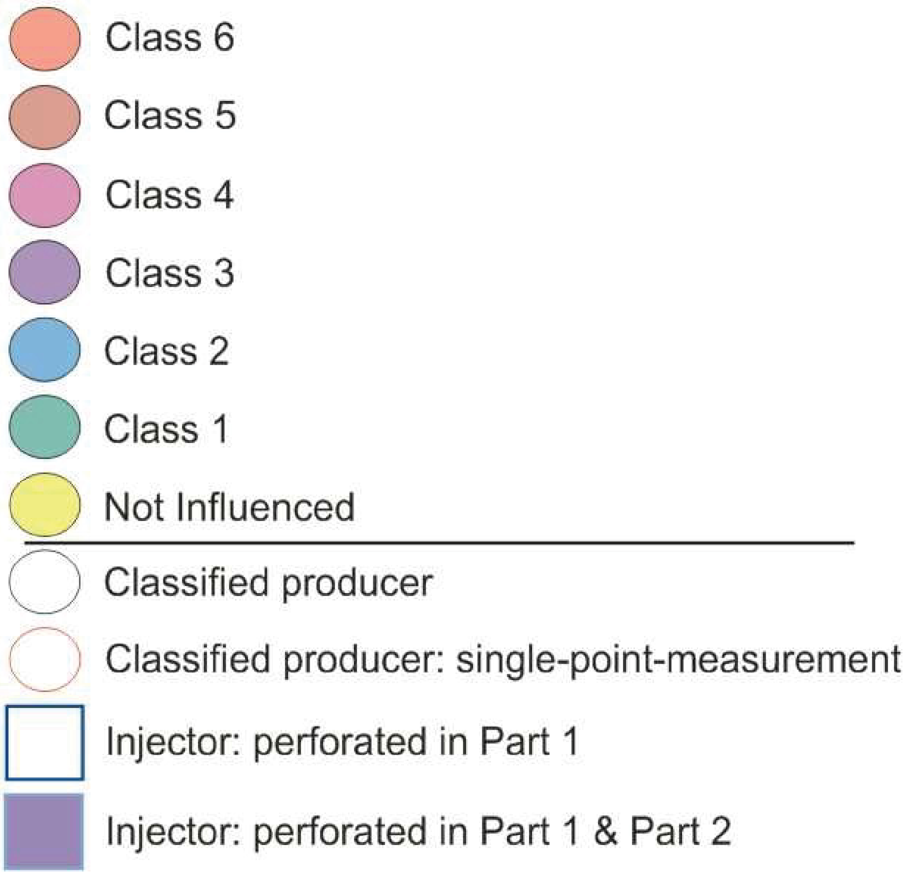


Fig.5.8: Legend for salinity maps

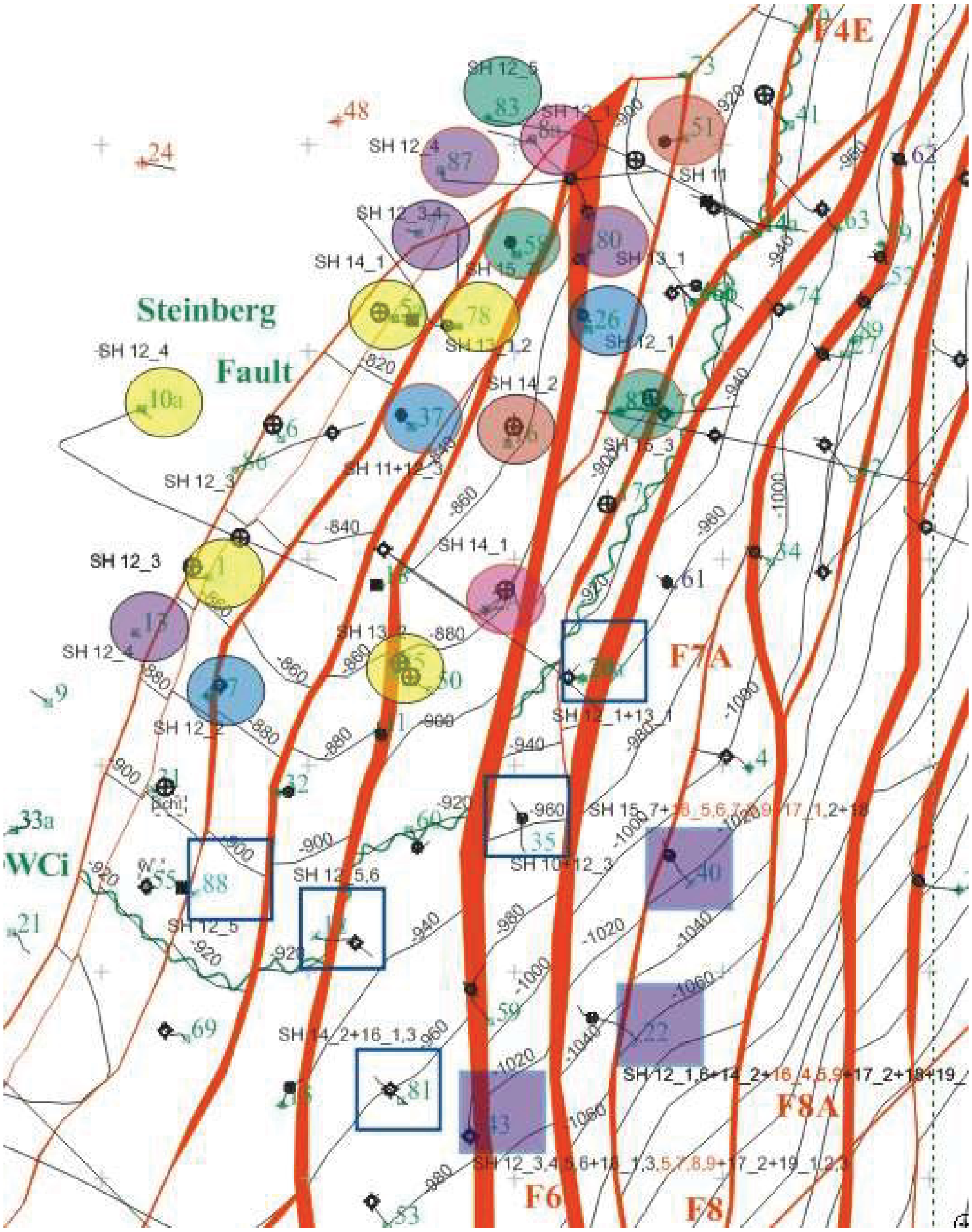


Fig.5.9: Salinity results of ‘Part 1’ represented on the map of the 15/1 Sarmat

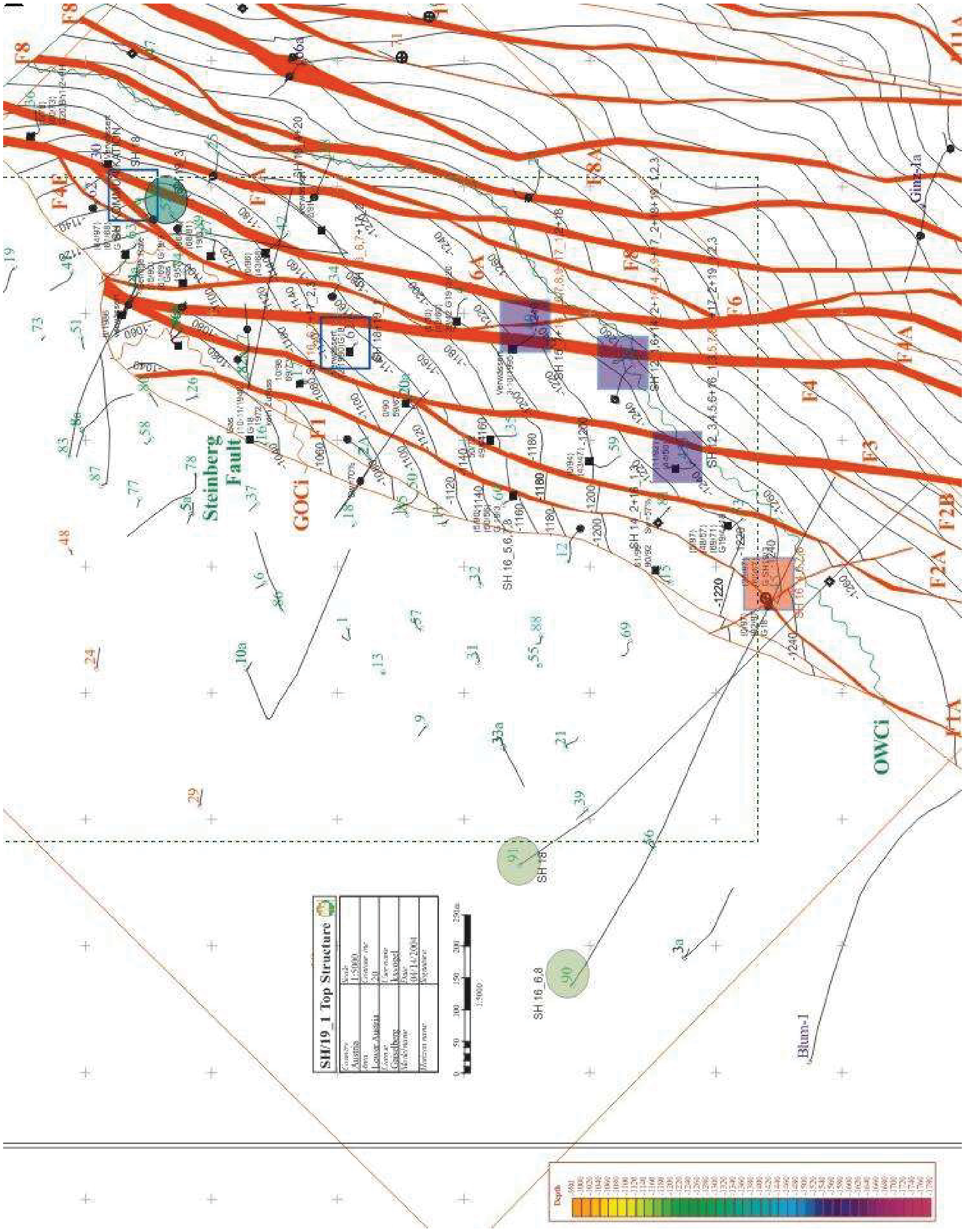


Fig.5.10: Salinity results of ‘Part 2’ represented on the map of the 19/1 Sarmat

6. Tracer

6.1 Introduction

Tracers were developed for tracking groundwater in the early 1900s and were neglected by the petroleum industry until the mid 1950s[17]. At this time, petroleum engineers started to make use of tracers to identify fluid paths in water flooded reservoirs.[18], [19]

Basically tracers are matters that are injected with water into a well, with the target to produce them in another one. The relation of the injected and produced amount of tracer material allows following the path of the water. The fact that the tracer travels along with the injected water can be used to characterize the flow path and dynamics within a waterflood pattern.

For example a sealing fault between an injector-producer configuration would act like a barrier to water and also to the tracer – which could be observed by no tracer breakthrough. On the other hand a high permeable channel would favor a quick tracer breakthrough.

The application of tracers is based on the assumption that the tracer travels with the same velocity as the water does. Essentially the reservoir properties constrain the ideal behavior of a tracer.[20], [21]

6.2 Reservoir Constraints

The arrival or even survival of a tracer strongly depends on the reservoir properties in which the tracer is used. Generally these materials have a negatively charged surface and contain diverse amounts of clay, which has a high cation-exchange capacity. Furthermore the reservoir has a reducing environment and the porous media has a large surface to volume ratio. Additional to that oil, water and gas can coexist and even the fact that bacteria can exist must be considered. By definition (Lake, 1990) ideal tracers are those which travel exactly with the same velocity of the water without any slip velocity. Therefore successful applied tracers do not interact with the reservoir properties mentioned above. These constraints can have different causes:[22]

6.2.1 Tracer Exchange

Ion exchange is a reversible process. This process can be observed when ions, adsorbed on the reservoir surfaces, exchange with ions in the solution and tend to be in equilibrium with them. Electrostatic forces are the reason why positively charged ions are absorbed by the negatively charged reservoir surface. If tracer ions are positively charged, they can exchange with the cations adsorbed on the reservoir surface. This fact is especially favored by the circumstance that the diameter of the pores is small and the velocity of the water in most of the waterfloods is low. This fact ensures that a local equilibrium between the ions on the surfaces and those in the water will arise. If this is the case the tracer ions become immobile and hence do not travel with the water velocity. Depending upon the kind of cation, it will spend a certain fraction of time on the surface and therefore will be delayed relative to the water (by the time spent on the surface). The velocity of the tracer slug will thus be lower than the true water velocity. It could also be the case that the cation is absorbed in such a strong way that it becomes totally immobile and thus loses the ability to trace the water.

It is very important to avoid such a case because non-recovery of tracer in production wells can be misinterpreted as a flow barrier.

A similar effect can happen if the tracer is soluble in the oil phase. The portion of tracer in the oil phase will travel with whose velocity. The tracer will be delayed by the fraction of time spent in the oil phase if the oil phase is immobile. If the phase is mobile, the situation becomes more complicated and will not be discussed in more detail. In both cases the velocity of the tracer does not reflect the true water velocity.

Even though the tracer could be recovered totally it is no more ideal because it does not reflect the true water velocity.[22]

6.2.2 Tracer Reaction

In case of the reversible ion exchange the tracer will arrive later than the water, but will ultimately arrive since the tracer is conserved. In case of irreversible exchange processes or the chemical form is altered by bacterial attack or chemical reaction, some or even none of the tracer may be produced with the water. Again the tracer can not be considered as ideal even if a portion of the tracer travels with the same velocity as the water does. Basically materials which lose solubility with time or react chemically with the ions in solution are not desired for the reasons above. Furthermore, carbonate and sulfate ions, which can react with many common reservoir ions and form insoluble precipitates are not desired.[22]

6.3 Tracer material for inter-well use

As a matter of fact ideal tracers are desired, but in many situations even a non ideal tracer behavior meets the needs. If surface-to-volume ratios are low and the velocities are relatively high, which is for example the case in fractured paths, dyes may be acceptable even if a portion of the dye is lost by absorption. A little delay in time may also not be that important if the purpose of the test is to identify only the source and direction or to identify sealing or conducting faults.

If the delay becomes too large, excessive dilution of the tracer could occur which can make detection difficult. If the durability of the tracer project is shorter than the delay, the non arrival during the sampling period could be misinterpreted as a flow barrier.[22]

Generally spoken, tracers should be soluble in water and have an anionic or neutral character. Furthermore the tracer should not react with any of materials present in the reservoir environment. The reasons above exclude cations, large and polarizable molecules (e.g. dyes), or materials which are easily reduced or reactive. To be also avoided should be materials that is extractable into oil, have a high vapor pressure or are subjected to bacterial attack in the reservoir.[22]

6.4 Tracer Classification

There is no well-accepted classification in the literature but generally spoken 'Tracers in the oil field' can be classified as follows:

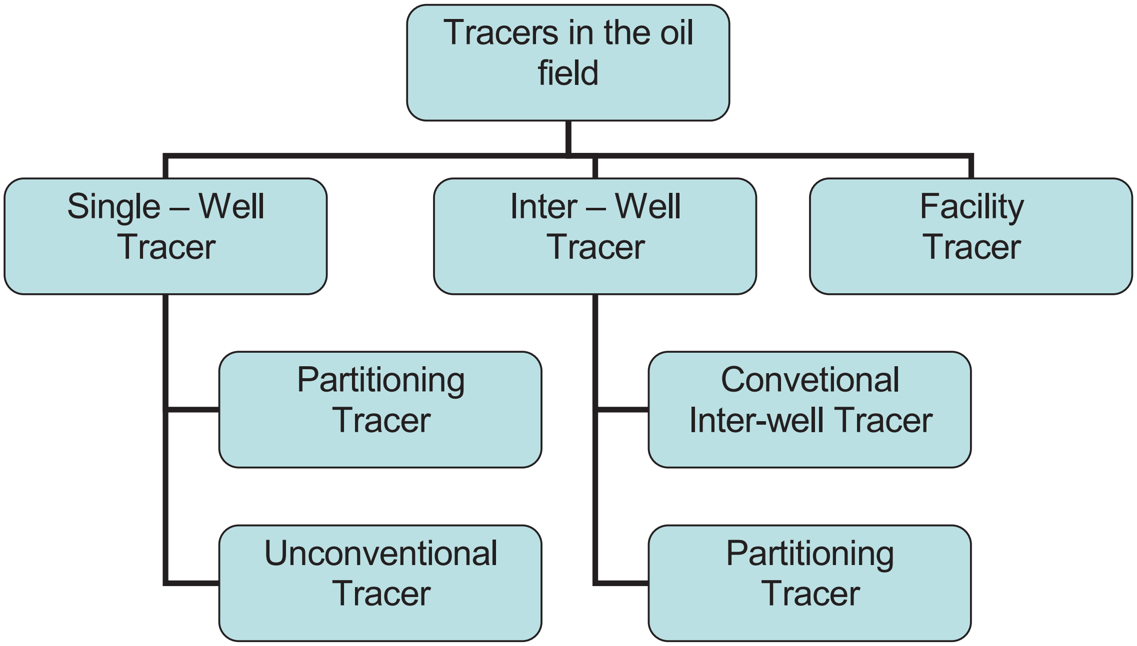


Fig.6.1: Tracer Classification

The basic classification indicates where the tracers are used. The author decided to split it up into single-well, inter-well and facility tracers.

In a single well tracer test the tracer is injected and produced from the same well. *Unconventional single-well tracers* are found especially in completion applications like fracturing

[23], cementing[24], gravel packing[25] and acid diversion[26].

Partitioning tracers are used as an in-situ method to determine fluid saturations in the reservoir. The residual oil saturation or connate water saturation can be measured. In case of a single – well partitioning test the saturation around the well bore are tested. An inter – well partitioning test, on the other hand, determines the inter-well fluid saturation.

The manner how a partitioning tracer behaves is totally different to a conventional tracer. Partitioning tracers are non-radioactive tracers and interact physically or chemically with the rock matrix or the reservoir fluids – they are soluble in oil as well as in water. The partitioning tracers are injected into the reservoir along with a conservative tracer. Due to the fact that the partitioning tracer continuously partition into and out of the oil phase, it propagates slower than the conservative tracer. This retardation of the partitioning tracer is a direct measurement for the oil volume in the reservoir and therefore very useful to determine the remaining oil saturation.[27], [28], [29]

In some literature the partitioning tracers are named 'active tracers' and the conservative tracers, which remain in the injected medium, 'passive tracers'.

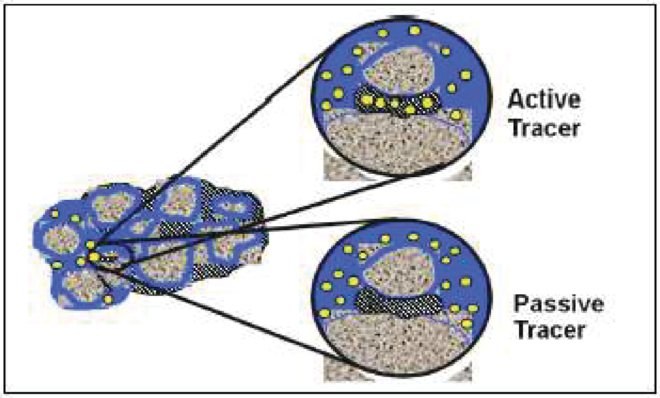


Fig.6.2: Difference between active and passive tracer [30]

Passive tracers are available, depending on their application for water and gas.

Inter-well tracers are used to identify qualitative information like directional flow trends, flow barriers and communication between reservoirs. Moreover, quantitative information as reservoir heterogeneity or sweep efficiency can be obtained by matching tracer data against a mathematical model.

Tracers in facilities mostly are dealing with operations where the produced fluids are gathered, separated, stored, treated and measured before they are sent for reinjection

or sale. Additionally tracers are used to monitor the treatment of corrosion, erosion and scale in oil field equipment.
Other applications:[22]

- Flow-rate measurement
- Flow-rate applications
- Flow regime in pipe and gathering lines
- Underground gas storage
- Oil, water and gas separators
- Pipeline leaks
- Environmental problems

6.5 Different group of tracers

In some literature the nature of tracers is used to classify them. Basically two groups of tracers are used in the petroleum industry:

- radioactive tracer

- non – radioactive tracer

  Radioactive tracers are chemicals which are tagged with radioactive isotopes that can decay into a stable state and emit beta or gamma radiation. The identification is possible due to the fact that these isotopes are unique in type and emitted energy. Radioactive tracers are widely used in petroleum industry. They have been used to study all aspects of drilling, completion and production profiles.[31]

Basically they are widely used because of there several advantages:[22]

- low natural background

- little reaction with reservoir fluids in rock

- similar transport behavior to the injected fluid

- low detection limit, hence little volumes to inject

The foremost disadvantage is deduced from its characteristic – radioactivity. These facts have to be considered in each and every single step.

Non – radioactive tracers do not contain a radioactive isotope and can be measured and identified by analytical methods (chapter 6.8.3)

6.6 Radioactive and untagged chemical tracers

It is important to state at this point that the radioactive and non – radioactive tracers are not different kinds of tracers. All waterflood tracers have chemical compounds with specific properties. In case of a radioactive tracer the chemical compound can be tagged with a radioactive compound that is suitable for this compound and purpose. In other words we can say that a radioactive tracer is a radioactively tagged chemical tracer – the same materials without the tagged radioactive isotope are also useful tracers.[22]

The radioactive characteristic provides these compounds a highly selective and sensitive analytic method for detecting them.[22]

6.7 Radioactively tagged tracers for water-flooding

Mainly two factors limit the use of radioactive tracers in water flooding:[22]

- the tracer must have the chemical properties to survive in the reservoir environment, and

- the nuclear properties must be appropriate for monitoring.

These two conditions limit the number of four nuclides combined in only three different chemical forms. Table 6.1 shows the radioactive tracers used in water-floods.

Compound (ion)	Formula	Radioactive Isotope
Hexacyanocobaltate	$Co(CN)_6^{---}$	^{60}Co, ^{58}Co, ^{57}Co, ^{14}C
Tritiated Water	HTO	^{3}H
Thiocyanate	SCN^-	^{14}C, ^{35}S
Halides	Cl^-, I^-	^{36}Cl, ^{125}I
Alcohols	$C_nH_{2n}OH$	^{3}H, ^{14}C

Tab.6.1: Radioactive inter-well water tracers [22]

6.7.1 Hexacyanocobaltate ions

The hexacyanocobaltate ion has a formation constant of 10^38 and is a very stable ion. First of all it was used in groundwater surveys (Halevy et al., 1958) and was then used as a cobalt isotope carrier. It is used as a carrier for two cobalt nuclides as well as for carbon-14.

Cobalt-60 can be monitored in a 3 inch diameter NaI well counter with an efficiency of 60 % whereas cobalt-57 with a good efficiency over 90%. Both nuclides can also be counted with a liquid scintillation counter with an efficiency over 90%.[22]

6.7.2 Tritiated water

Tritiated water has the longest history of application in water flooding. The difference to conventional water is given by the fact that it contains hydrogen of mass 3 instead of mass 1 hence the chemical properties are the same. However, the kinetic affect is observed because of the large mass difference between the two isotopes. This fact that the rate of conventional water differs from that of tritiated water allows enrichment of tritium in water by electrolysis. On the other hand the rate difference is so minor that it does not affect it when used as water tracer.

It presents no external radiation hazard and because it does not emit no gamma radiation and beta particles with very low energy. The fact that it emits beta particles with very low energy demands internal counting by liquid scintillation.

When counting directly from produced brine the effectiveness is low (about 25%). This value can be increased by distilling off the water sample.[22]

6.7.3 Other anionic complexes

Despite of the complex cobalt cyanide the other complex anions stated in the literature are the chelating complexes of ethylenediamine tetraacetic acid (EDTA) and its analogs (Watkins et al., 1962), using radioactive cations. Due to the exchange with other cations in solution that form stronger complexes and/or are fare more numerous their success was limited. It can be said that the field of application strongly depends on the presence and concentration of competing divalent ions (e.g. Ca^{++}) that form strong complexes.[22]

Due to the fact that radioactive tracers have a very low detection limit and hence only little volumes have to be used, these tracers were applied in large oil fields with large potential of dilution. In comparison, the ‘chemical tracers’ had several analytical problems with the consequence of a rather high detection limit which limited their use for oilfields with short water paths.[22]

The analytical strategies developed in such a way that nowadays even ‘chemical tracers’ can be detected in the ppt-range. These developments drastically increased the field of application for ‘chemical tracers’. The main advantage of ‘chemical tracers’ is the fact that no additional HSE-arrangements because of radioactivity have to be considered.[22]

6.8 Non-radioactively tagged tracers

The number of non-radioactive tracers, which have been used successfully, are limited to those of table 6.1. These are halide ions, nitrate ions, thiocyanate ions and isotopically tagged water.

As a matter of fact, also other tracers are in use, but a literature search has revealed no detailed description or field tests. This can be explained by the fact that most of those research activities and tests are financed by companies, hence not accessible for public.

On the contrary to the radioactive tracers, where the task was to find an appropriate radioactive nuclide, the task in chemical tracers is to find the right analytical method for analyzing the brine.

Unlike radioactive tracers, the analytical methods and procedures are variable. For that reason it is beyond the scope of this thesis to adequately cover all of them. The main analysis techniques, however, are described.

The greatest problem with chemical tracers is the amount to be injected, especially in big water-floods. The only way to avoid this problem is to lower the detection limit of the analytic process. In other words in can be said that the costs of tracer materials drastically increase with increasing size of the water-flood. New analytical methods are constantly developed which reduce the detection limit but are publicized very rarely because of the reasons mentioned above.

Basically, the problem didn’t change – finding materials with low detection limits which survive in the reservoir environment and follow the path of the water.

Most of the steps in the tracer test design are not different to those of the radioactive ones, except the understanding of the MDL (Minimum Detecting Limit). However, one factor is not important for radioactive tracers – the natural occurrence of the tracer in the reservoir. If the natural occurrence exceeds the MDL for the tracer, it must replace the MDL in the tracer design equation. For that reason the highest measured concentration is taken as well as a safety factor to ensure a clear identification of the tracer response curve.

For the tracer design it is very important to know the MDL as well as the measurement error, especially if the measurements are outsourced and hence outside the sphere of influence. In addition to that the fraction of active (which is measured) material in the tracer must be known.

One of the big advantages of radioactive tracers is the fact that analytical procedures and detection methods are very similar. The situation becomes much more complex when dealing with chemical tracers. In the past 20 years an enormous expansion of analytical methods was observed. Much of this work is published in papers and analytical journals. As already mentioned, it would go beyond the scope of this thesis to describe them adequately.[22]

It is important to note that the analytical method is greatly affected by other materials in solution. In other words, equal amount of tracer in different water compositions doesn’t ensure equal success in the analysis.

How the right amount of tracer to be injected is calculated is described in detail in the design chapter.[22]

6.8.1 Chemical tracers available

As indicated above the most common and field-tested (in open literature) inorganic tracers are nitrate, thiocyanate, bromide and iodide ions. The best analytical method therefore is the ion chromatography. The MDL should be determined by the laboratory which is in charge of doing the measurements. It is important that this evaluation is performed with produced water of the field where the tracer test is planned to analyze the influence of other ions in solution.

Nitrate is the cheapest tracer available. Ammonium nitrate delivers the highest fraction of active material (tracer) per unit weight, and is therefore the most effective one.

Ammonium nitrate is used as fertilizer in agriculture and is often used as an explosive when mixed with many organic compound and must therefore be treated with care. Experience showed that it is safe if it is dissolved in water. One of the biggest problems is the natural background present in the reservoir. An example should make it descriptive[22]: Assuming a natural concentration of nitrate of 500ppb. Due to the high natural concentration this value is taken for the MDL. Those assumptions would lead to a total amount of tracer (10xMDL) of 1026 kg per million barrel. For a field with 10 million barrels it will become a logistics problem.[22]

Iodide and to a moderate extent, bromide, have been successfully used as a water tracer. However, both are more expensive than nitrate or even thiocyanate.

Radioactive tracers use the hexacyanocobaltate complex ion to carry the cobalt isotopes and carbon-14. The cobalt isotopes can be used in sub-micro quantities to trace water. New methods make it possible to measure non-radioactive cobalt in the nanogram region leading to concentrations in the ppb range. The combination of inductively coupled plasma and mass spectroscopy (ICP/MS) can detect many of the transition elements, including cobalt, at a ppb level.[22]

6.8.2 Tracer without or less field-tests – reported in open literature

A number of petroleum research institutes invested much effort to develop a series of new tracers and analytical methods. Most of them offer comprehensive field surveys for oil companies. Those companies carry out all steps of the tracer program starting with the tracer design, preliminary work, pumping the tracer down into the reservoir and even the samples are sent to a research institute for analysis. Most of the technology is kept confidential and therefore not accessible for public use. The tracers stated below are some of those which have been tested in petroleum research institutes:

Most of the organic tracers didn’t survive in the reservoir environment; however some of them look promising for the use as water tracers.

For example strongly acid perfluorinated compounds (organic compounds in which all the hydrogens have been replaced by fluorine), including species such as trifluoracetic acid (TFA).

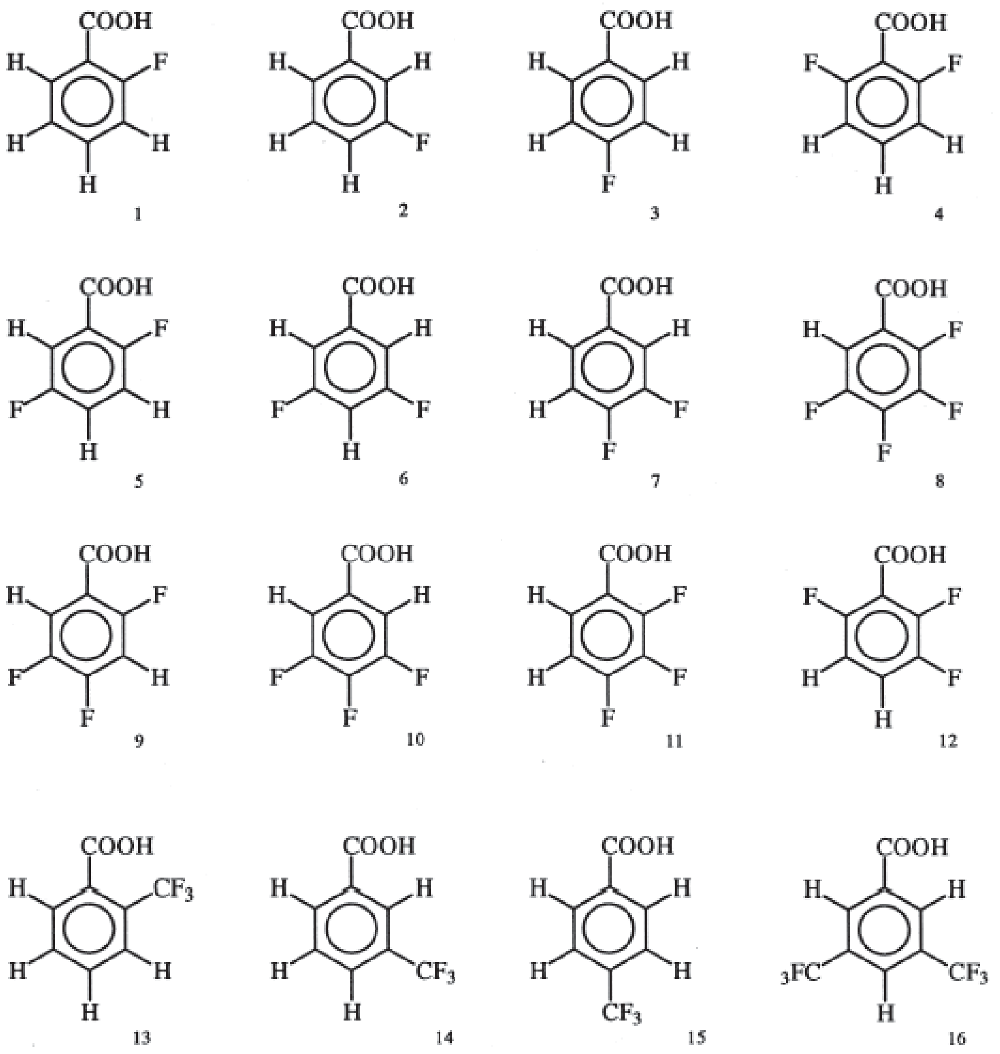
The TFA exists as the trifluoracetate in solution. It is a bactericide and will not partition into the oil face furthermore it is stable under reservoir conditions and can be detected by ion chromatography.

Other possible tracers are cyanides of the transition metals which are unusually stable. Suitable for the purpose would be the dicyanoaurate complex ion($Au(CN)_2^-$) and the tetracyanonickelate complex ion ($Ni(CN)_4^{-2}$). The gold complex ion has already been successfully tested as a groundwater tracer (Thacher and Ramsey, 1977).

All alcohols have been tested for that purpose – they should not be used because of their partitioning into the oil face.[22]

- Fluorinated Aromatic Carboxylic Acids

Fluorinated Aromatic Carboxylic Acids are used by service companies for inter-well tracer tests and are often named FBAs (Fluoro-Benzoic-Acids). Up to 16 Fluorinated Aromatic Carboxylic Acids can be used as tracers which make a simultaneous use of tracers possible. A analytical method[32] for the ultra-trace determination makes it possible to analyse up to 15 FBAs simultaneously. With this method FBA can be determined in the ppt-range which reduces the amounts of tracers needed drastically. Furthermore FBAs have a long-term stability, are thermal stable and no subject to bacterial attack.



1: 2-fluorobenzoic acid (2-FBA); 2: 3-fluorobenzoic acid (3-FBA); 3: 4-fluorobenzoic acid (4-FBA); 4: 2,6-difluorobenzoic acid (2,6-DFBA); 5: 2,5-difluorobenzoic acid (2,5-DFBA); 6: 3,5-difluorobenzoic acid (3,5-DFBA); 7: 3,4-difluorobenzoic acid (3,4-DFBA); 8: 2,3,4,5-tetrafluorobenzoic acid (2,3,4,5-TFBA); 9: 2,4,5-trifluorobenzoic acid (2,4,5-TFBA); 10: 3,4,5-trifluorobenzoic acid (3,4,5-TFBA); 11: 2,3,4-trifluorobenzoic acid (2,3,4-TFBA); 12: 2,3,6-trifluorobenzoic acid (2,3,6-TFBA); 13: 2-(trifluoromethyl)benzoic acid (2-triFmeBA); 14: 3-(trifluoromethyl)benzoic acid (3-triFmeBA); 15: 4-(trifluoromethyl)benzoic acid (4-triFmeBA); 16: 3,5-di-(trifluoromethyl)benzoic acid (3,5-ditriFmeBA)

Fig.6.3: Structures of the 16 fluorinated aromatic carboxylic acids [32]

6.8.3 Analytical methods

The analytical needs, when dealing with non-radioactive tracers, are high-resolution and detection sensitivity.

The high sensitivity comes from narrow, sharply resolved separations and low volume detectors, which results in high peak concentrations at very low noise.

Basically the analytical methods are constantly revised due to the changes in technology. Currently the standard method for analyzing anions, such as nitrate, thiocanate and the halides is ion chromatography (IC). No comparably sensitive analytical method was available before the development of IC. It can be said that IC made it possible to use chemical tracers as water flood tracers. The classical colorimetric methods are cheaper but two magnitudes lower in sensitivity. It is really important for the tracer designer to know the limitations of the analytical method – especially the detection limits and procedures which are used.[22]

6.8.3.1 Ion Chromatography

'Ion chromatography is the application of high-performance liquid chromatography (HPLC) to the separation and analysis of inorganic ions in aqueous solution.'[22]

Ion chromatography, or more accurate, ion exchange chromatography is a process in which ions and polar molecules are separated by the charge properties of the molecules. It can be used for almost any kind of charged molecule. Ion chromatography retains analyte molecules based on coulombic interactions. The stationary phase displays an ionic functional group that interacts with analyte ions of opposite charge. It can be divided into cation exchange chromatography and anion exchange chromatography:

- Cation exchange chromatography retains positively charged cations because the stationary phase displays a negatively charged functional group.
- Anion exchange chromatography retains negatively charged anions using a positively charged functional group.

Due to the fact that most tracers are anionic or neutral in character, only anion exchange chromatography is applicable.[22]

Typical technique: The sample is forced into the column which contains stationary phase material. This can be a resin or a gel matrix which consists of agarose or cellulose beads with covalently bonded charged functional groups. The mobile phase, a buffered aqueous solution, carries the sample through the column. The target analyte (anions or cations) retains on the stationary phase, but it can be eluted by increasing the concentration of a similarly charged species that will display the analyte ions from the stationary phase. The target analyte is then supposed to be detected by some means, typically by conductive or UV/visible light absorbance.[22]

Chemical tracers need, in contrast to radioactive ones, separate chemical methods for each and every single ion.

To meet the increased demand of higher solution in the separation of materials by liquid chromatography HPLC was developed.

Basically, HPLC is based on the same principle as the classical ion chromatography. It contains a column with a stationary phase, an automatic detection system and a system which forces the mobile phase through the column. On the other side, the operational characteristic is very different.

In the HPLC technique the stationary phase is optimized to reduce band spreading. Improved mass transfer rates are obtained by packing the column with very small, microsized particles with low solute exchange capacities – column diameters are also kept small for the same reason. The small diameters demand a high pressure to ensure certain flow rates. Several thousand pounds per square inch are required to ensure the desired flow rates. For that reason HPLC is sometimes also known as high pressure liquid chromatography.

The mobile phase must be selected in a way that it enhances the separation of the solute by the stationary phase and that it is compatible with the detector. The rate is usually controlled by a computer which allows programming it for a variety of operations. A great assortment of detectors with different sensitivities and selectivities exists on the market which then generates the chromatogram. The solutes can be identified by the recorded peak for each solute according to its arrival time and the concentrations obtained from the peak areas. The setting of the columns enables the receipt of sharp separations in a relatively short time. There is still research going on to develop new ion-exchange materials, in particular, ion-exchange beds with capacities limited to a small, porous layer at the surface, for that purpose.

Figure 6.4 shows the schematic of HPLC – in reality the equipment is far more complex than the simple schematic.

The sample to be analyzed is introduced in a small volume to the stream of the mobile phase and is then retarded by specific chemical or physical interactions with the stationary phase as it passes through the length of the column. The amount of retardation greatly depends on the nature of the analyte, stationary phase and the composition of the mobile phase. The time at which the analyte elutes is called the retention time and is considered as unique identifying characteristic of a given analyte. As already mentioned above, the use of small capillaries and hence high pressures gives the components less time to diffuse within the column which leads to an improved resolution in the resulting chromatogram.[22]

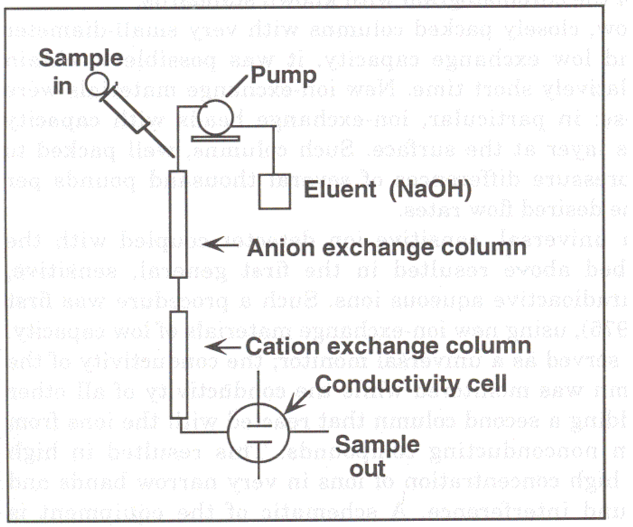


Fig.6.4: Ion chromatograph schematic [22]

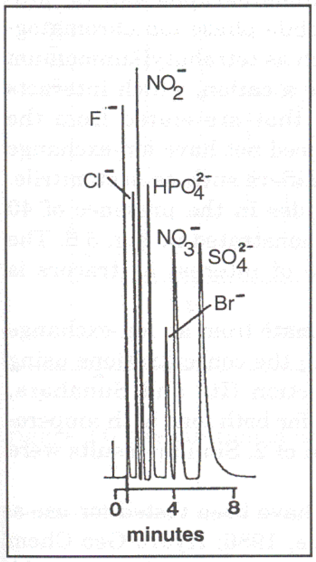


Fig.6.5: Anion separation and analysis by IC [22]

The detection methods for ion chromatography can be divided into three groups:[22]

- electrochemical methods, including amperometric, potentiometric and conductimetric procedures
- spectroscopy, which includes ultraviolet/visible absorbance, refractive index, fluorescence and atomic absorption/emission
- postcolumn reactions, which use a secondary reaction to monitor tracer response.

6.8.3.2 MINIMUM DETECTION LIMIT

The dynamic range is defined by the ratio of the minimum detection limit (MDL) and the maximum permissible concentration (MPC). For non-radioactive tracers the MPC is fixed by two factors: cost and interference. The injection of even cheap materials can become costly when injecting a large amount. The best way to increase the distance over which a tracer can be tracked or to lower the amount of tracer to be injected, is to lower the detection limit.

A hypothetical, multi-pattern five spot water flood example should make that descriptive:[22]

The distance between the producers and the injector is 100ft; the formation thickness is 50ft; the porosity is 0.25 and the water saturation is 0.5. The tracer quantity to produce 10 times the MDL for the closest well is calculated according the procedure stated in chapter 7.3.2.1. For detecting the tracer even at wells outside the pattern (2000ft) an additional factor of 10 is required to meet the additional dilution by additional water. The results are shown in table 6.2[22]

(MDL) (mass/vol)	Tracer required, near wells @ 10 x MDL (1000 ft)	Tracer required, far wells @ 100 x MDL (2000 ft)
1 ppm	12,250 lb	122,500 lb
10 ppb	1225 lb	12,250 lb
1 ppb	122.5 lb	1225 lb

Tab.6.2: Effect of MDL on detection in far wells [22]

Commercial laboratories are able to achieve a sensitivity of about 1 ppm. Special methods can lower the MDL down to 20 to 50 ppb. Sensitivities of 1ppb requires additional method development. Petroleum research institutes nowadays even make it possible to analyze tracer down to a ppt-range.

In general, methods achieve a sensitivity of 1 ppm – to go beyond this level special procedures are needed which can be divided into three categories:[22]

- using large injection volumes into the chromatograph
- preconcentration of the sample
- special analytical methods

6.9 Tracers in the oil field

This chapter should give a good overview about tracers used in the petroleum industry and problems which occurred during their application.

Mr. Du[21] and Mr. Guan[21] from Texas A&M University reviewed inter-well tracer tests which were found in the open literature. Additionally they were faced with the problem that not all papers were adequately described.

They found out that fewer papers about tracer technology in petroleum industry literature are found than in hydrology literature. This may be explained by the fact that tracer tests in petroleum industry are more confident than in hydrology industry. Most papers don't even present the chemical composition of the tracers – they are identified with their trade names only. Just a few papers report some details about tracer choice or tracer test design.

As a result of this it is difficult for the petroleum industry to learn from past mistakes. This could be a reason for the slow development of tracers in the petroleum industry. [21]

The problems encountered in the reviewed papers should be taken as a clue for the tracer test planned in the Gaiselberg Field. Findings of this survey concerning tracer test-design and implementation were also considered in the Gaiselberg tracer test (chapter 7-9).

Most papers reviewed are from SPE and the Petroleum Society of the Canadian Institute of Mining (CIM).

Appendix C presents all reviewed inter-well tracer tests. Field name, tracer type, tracer name and how the information was obtained (analysis method) are quoted.

Figure 6.6 shows that approximately 60 percent of the inter-well tracer tests are water tracer tests and about 40% are gas tracer tests.

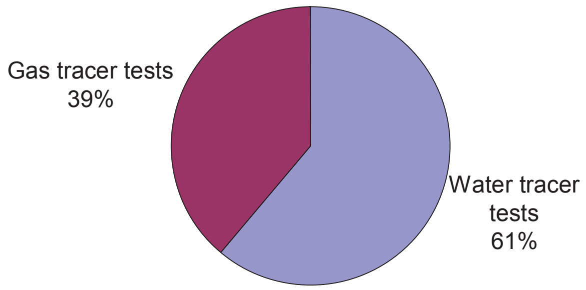


Fig.6.6: Inter-well tracer tests conducted in petroleum industry [21]

6.9.1 Unsuccessful inter-well tracer tests

A lot of factors can cause the inter-well tracer test to be unsuccessful. The worst case is that the tracer is not recovered. Several reasons can cause a non-production of the tracer.

- Tracer moves to an area which has not been considered in the sampling program
- Tracer is injected in an unwanted zone because of completion damage
- Interaction with reservoir rock
- If the durability of the tracer project is shorter than the delay

In cases mentioned above the non arrival could be misinterpreted as a flow barrier.
One approach to avoid the problem mentioned above is a production/injection data analysis. If a candidate injector does not show a significant pressure build up after a large volume of water is injected, this may be an indication for fractures or high-permeable channels that short-cut the sweep between the injector and producer. In this case a special focus should be given on selecting monitor-wells.
A simulation study prior the test will also provide a good insight.

The most encountered problem which leads to a failure is poor sampling. In this case even a good planned and executed inter-well tracer test will fail victim due to either poor sampling frequency or a poor sampling technique. Due to the fact that sampling costs are low it is much better to take more samples than not to take enough. Not all taken samples must be costly analyzed.

In the reviewed papers factors such as an insufficient amount of tracer and/or not well defined objectives also lead to failure.[21]

7. Tracer Test Design

7.1 Objective of the tracer test

Due to its importance the objective of the tracer test is stated here again:

The main objective of the tracer project in the Gaiselberg Field is to improve the reservoir description by defining the inter-well communications and flow paths. This information should enable to identify by-passed oil, which in succession should be produced by improving the water-flooding strategy.

Another objective of the tracer test is the identification of communication across faults which should also advance reservoir description.

7.2 Selection of test pattern

The selection of the test pattern is a very critical part of the design phase. Besides the injectors and producers themselves, the distance between them also plays an important role. The distance is directly related to the amount of tracer to be injected – a smaller distance will lead to significantly reduction of the costs, hence the transporting, handling and regulatory approval is much easier.[10]

7.2.1 Injectors

Basically, the injectors can be divided into three classes. First choice injectors have a high injection rate and a low well-head pressure because these are symptoms for potential problem injectors. If the well does not build up pressure after injecting large volumes of water, this may indicate the presence of fractures or high-permeable channels that are short-circuiting the sweep between injectors and producers. The high rate only would imply a higher magnitude of the mentioned problem.
Second choice injectors have a quick connectivity to a producer.
Last but not least, injectors, located in areas with a good reserve potential should be taken into account (third choice).[10]

7.2.1.1 Injectors in the Gaiselberg Field

Injector	Well-head pressure [bar]	Injection rate [m³/h]	Injection rate [m³/d]	Comment
GA-035	15,5	10	240	
GA-081	16	7	168	
GA-088	17	6	144	
GA-061	19,5	5	120	Perforation
GA-022	18	3,5	84	tubing
GA-040	19,5	3,5	84	
GA-020A	20	2,5	60	
GA-049	8	2,3	55,2	not zone of interest
GA-012	20	1,5	36	
GA-043	17,5	1,5	36	tubing
GA-045	18	1,5	36	not zone of interest

🟩	first choice
🟦	third choice
🟧	not of interest

Tab.7.1: Selection of injectors in the Gaiselberg Field

The fact that only rare statements about connectivity between producers and injectors are possible (chapter 2 – 5) eliminates ‘second choice’ injectors in table 7.1.

Due to the actual completion, it was not possible to perform temperature measurements in GA-022 and GA-043. Temperature measurements (chapter 10) showed that an already cemented perforation in GA-061 is not tight – for this reason it was excluded. Injectors, perforated in Part 1 and 2, having no temperature profile, were excluded from the tracer project because of the possible ambiguities arising at the interpretation of the tracer test.

7.2.2 Monitoring wells

All wells where the tracer breakthrough is expected should be monitored – as a matter of course this is critical.

To come off best, all active production wells should be sampled but the economic point of view often limits the number of wells and the frequency of sampling. [10]

Several tools which are already mentioned in chapter (chapter 2-5) can be used for selecting wells which should be monitored.

7.2.2.1 Monitoring wells in the Gaiselberg Field

To avoid a failure of a costly tracer test all possible outcomes of the tracer test must be considered. Due to the complexity of the Gaiselberg Field all active wells should be sampled. More details on sampling in the Gaiselberg Field will be discussed in chapter 7.4 , 8.1.4 and 8.2.4.

7.3 Selection of tracer

As already mentioned, the selection of the right tracer is very crucial. The chosen tracer should meet the demands of the previous defined objectives. A perfect tracer would have to fulfill the following points:[10], [21]

- should be soluble in water and move with the same speed as the injected medium
- should be stable (except radioactive tracers) to make later (back-tracking) analysis possible
- should not be absorbed or altered by the reservoir environment
- should be in very low concentrations (or non existent) in the reservoir environment
- should be detected in very low concentrations – low minimum detection limit
- should be cost efficient
- should be safe and easy to manipulate (HSE)

As a matter of fact it is impossible to find an ideal tracer – a tradeoff is inevitable.

7.3.1 Tracers in the Gaiselberg Field

The selection of tracers is a very critical task for the success of the project.
Basically there are four main types of tracers: radioactive salts, dyes, salts and alcohols.

- Examples for radioactive salts are: Tritium (^3H), Thiocyante (14CNS-), Cobalt 60 (60Co(CN)6-3), Chlorine 36, and Sodium 22.

Due to HSE and environmental concerns radioactive tracers cannot be used in the Gaiselberg Field.

- Examples of dyes are: Fluorescein, Eosin, and Rhodamin.

They tend to adsorb onto the reservoir surface and partition into the oil phase and thus can only be used when very short breakthrough times are expected, like in fractured or vugular reservoirs. Due to the lack of reservoir properties and the complexity of the Gaiselberg Field no serious estimation of breakthrough-times can be done and therefore the use of dyes is not recommended.

- Examples of salts are: Chloride, Bromide, Iodide and Nitrate

Nitrate is degraded by bacteria. The reservoir fluids in the Gaiselberg Field contain a high level of Bromide (up to 69mg/l), Iodide (up to 54 mg/l) and Chloride (up to 15600 mg/l) which make their use as a tracer impossible (chapter 7.3.2).

- Example of alcohols are: Methanol, Isopropanol, Propanol and Ethanol.

Alcohols tend to partition into the oil phase and are subject to bacterial attack and therefore not recommended as tracers. [10], [21]

- Other Tracer

- Rhodanit (SCN)

Past tracer tests(OMV) showed that Rohdanit is non-absorbing, has a long term stability, is not subjected to bacterial attack and can easily be analyzed. Rhodanit is a tracer candidate for the Gaiselberg Field

- Fluorinated Aromatic Carboxylic Acids (FBAs)

They are described more in detail in chapter 6.8.2 and are favorite candidates for a multiple tracer test in the Gaiselberg Field.

7.3.2 Conclusions

As a result of its characteristics, Rhodanit would be the best choice for a single inter-well tracer test. For a multiple tracer test FBAs are the best choice because of their chemical properties, their extremely low MDL and the possibility to analyze them simultaneously.

The following table summarizes the advantages and disadvantages of the tracer candidates, Rhodanit and FBAs, for the Gaiselberg Field.

	PROS	CONS
SCN	- low price per unit of mass - less analysis costs - indicator tests available - non toxic - not subject to bacterial attack - field tested	- higher MDL (0,05mg/l) - therefore more tracer material is needed - multiple tracer test is not possible
FBA	- very low MDL (10-8 mg/l) - mulitple tracer test is possible - non-toxic - not subject to bacterial attack - field tested	- high analysis costs - service company is necessary - high price per unit of mass

Tab.7.2.: Pros and Cons of Rhodanit and FBAs

The complexity of the Gaiselberg Field causes many uncertainties like estimating breakthrough times, selecting monitoring wells and estimating the water volume in which the tracer will be diluted. All these points drastically influence the costs of a costly multiple FBA tracer test. These circumstances led to the decision that a Pilot test should be performed at first. This pilot test should increase the knowledge in the following areas:

- sampling handling
- breakthrough times, hence sampling frequency
- sealing properties of faults (especially fault F4), hence selecting possible monitoring wells
- ‘tracer response curve’, hence information about the dilution volume.

The information obtained in the Pilot-Tracer-Test could significantly reduce the costs of the multiple FBA tracer test.

7.3.2 Tracer volumes and concentrations

An insufficient amount of tracer can lead to the failure of the tracer test. The three most important parameters to calculate the amount of tracer to be injected are:[33]

- detection limits (MDL)
- maximum permissible concentration
- reservoir properties

There are two methods for determining the amount of tracer to be injected. The first approach is based on a model which originally was advocated by Brigham and Smith in 1965 and modified by Addaszadeh and Brigham in 1984. The most widely used method, however, is the total dilution method.

The model of Brigham and his co-workers are also used for tracer test analysis and thus are described in chapter 9.7.2.

The most advanced method is numerical simulation using a detailed reservoir description.[10]

7.3.2.1 Total dilution method

This method is based on the assumption that the tracer is uniformly diluted in the reservoir by the entire swept water volume – an average concentration is estimated.

The rule of thumb says that the tracer will be diluted by the total volume of water displaced in the test pattern, consequently as much tracer will be added to ensure the detection at the production wells considering the minimum detection limit (MDL) of the tracer. In cases where the tracer is existing in the reservoir the MDL is exchanged by the highest measured concentration of this compound times a safety factor to reduce the noise.

The first step in the total dilution method is to calculate the dilution volume which is the water-filled pore volume between injector and producer. Generally, a radial geometry is used, but it can be modified with any known reservoir geometry, for example if flow channels or barriers are known.

The rule of thumb recommends that the smallest injection pulse should have such a concentration so that it is produced with an average concentration of 10 times the MDL (Safety-factor).[22]

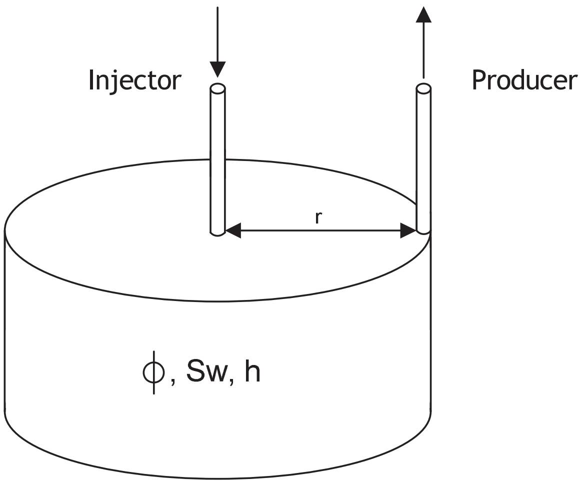


Fig.7.1: Principle of total dilution method

The dilution volume can be calculated by[22]

$$V_d = r^2 \cdot \pi \cdot h \cdot \phi \cdot S_w \cdot F \qquad \text{Eq.1}$$

Whereas:
$V_d =$ Dilution volume
$r =$ Distance between injector and producer
$h =$ Thickness
$S_w =$ Water saturation
$\phi =$ Porosity of the formation
$F =$ Correction factor which accounts for the dilution of the tracer due to an additional injector in the same compartment.

The amount of tracer to be injected can then be calculated as follows:[22]

$$W_T = V_d \cdot MDL \cdot S \qquad \text{Eq.2}$$

Whereas:
$W_T =$ Tracer material needed
$V_d =$ Dilution Volume
$MDL =$ Minimum detection limit
$S =$ Safety factor

Some tracers are always compounded with other chemicals, e.g. Rhodanit (SCN): Ammonium-Rhodanit (NH_4SCN), Kalium-Rhodanit (K-SCN) or Natrium-Rhodanit (Na SCN). Due to the fact that only Rhodanit is the tracer material, equation 2 calculates only the amount of active material. An example should make this descriptive: e.g. Ammonium-Rhodanit (NH_4SCN). NH_4 has a molecular weight of 18g/mol and Rhodanit (active material) of 58g/mol. The amount of active material can be calculated as follows:

$$ActiveTracer[\%] = \frac{58g/mol}{18g/mol + 58g/mol} \cdot 100 = 76{,}31\% \qquad \text{Eq.3}$$

Only 76,31 mass-percent of the Ammonium-Rhodanit are tracer material. The real amount of tracer can then be calculated by:

$$W_T = V_d \cdot MDL \cdot S \cdot \frac{M_S}{M_A} \qquad \text{Eq.4}$$

Whereas:

$M_S =$ molecular weight of tracer compound

$M_A =$ molecular weight of the active tracer material

5.3.2.2 Tracer quantities and dilution volumes in the Gaiselberg Field

The tracer quantities are calculated according to the procedure described in the previous chapter. The detailed calculations can be found in Appendix D.
Table 7.3 summarizes the results:

Well	Tracer	Dilution Volume	Tracer amount
		[m³]	[kg]
GA-088	Rhodanit (NH_4SCN)	1411088	924,6
GA-012	FBA	27116543	54,3
GA-020A	FBA	21617142	43,3
GA-035	FBA	23832899	47,7
GA-081	FBA	42369598	84,8
GA-040	FBA	37665708	75,4

Tab.7.3: Tracer quantities and dilution volumes in the Gaiselberg Field

7.4 Schedule for monitoring

The main reason for failure in tracer programs is poor sampling [22]. This shows that monitoring is most critical. It is far better to take too many samples than to take not enough - sampling is one of the cheapest parts in a tracer program.
A proper field sampling needs a sample-frequency schedule for the well selected for monitoring. The sampling frequency should be highest in the beginning of the tracer project to avoid the missing of early breakthrough. After breakthrough the sampling frequency can be reduced to get at least enough measurement-points to define the tracer response curve.
In the beginning not all collected samples have to be analyzed – it is sufficient to analyze every tenth sample. If no tracer is found, the samples taken before can be discarded. If a tracer is found in that sample, the ‘breakthrough sample’ can be found by backtracking. Once the breakthrough is found, all samples should be analyzed until the tracer response curve is defined.

Due to the fact that the sample frequency is a function of breakthrough times it is necessary to estimate those. The complexity of the Gaiselberg Field only allows a simple calculation to get a rough estimate. The principle of the calculation is shown in Figure

$$v_{pore} = \frac{q_{inj}}{A \cdot \phi}$$

$$t_{break-through} = \frac{s}{v_{pore}}$$

Whereas:

$v_{pore} =$ Pore velocity

$q_{inj} =$ Injection rate

$A =$ Cross-section (thickness of formation times lateral extension of the water-channel)

$\phi =$ Porosity of the formation

$t_{break-through} =$ Breakthrough-time

$s =$ Distance to producer

The flux is divided by the porosity to account for the fact that only a fraction of the total formation volume is available for flow. The pore velocity would be the velocity a conservative tracer would experience if carried by the fluid through the formation.

To account for the earliest possible breakthrough it is assumed that the entire water quantity of GA-088 is injected towards the producers. Furthermore, it is assumed that the water stays all the time in SH12/5 for the same reason.

Once a week the water-flood should be analyzed to observe possible recycling of the tracer.

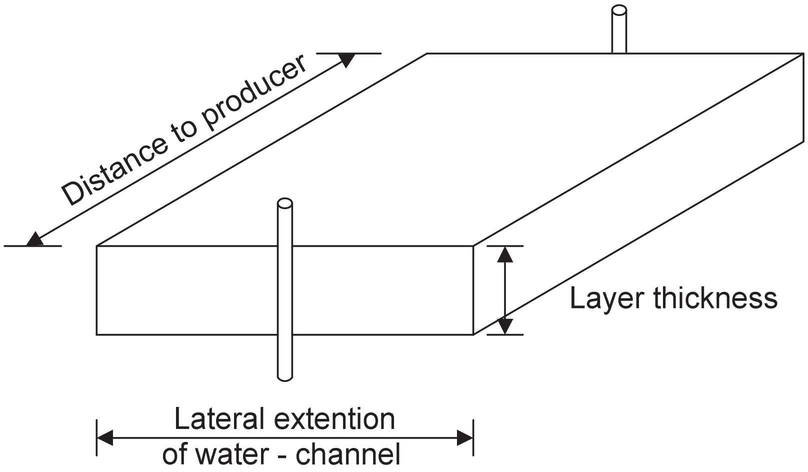


Fig.7.2: Principle of calculation

Injection Rate - GA-088:	6	m^3/h
Thickness - SH12/5:	5	m
Porosity - SH12/5:	0,23	-
Distance to Producer	200	m

Lateral extention of the water channel	v_{pore}	Time	time
[m]	[m/h]	[h]	[days]
1	5,22	38	2
2	2,61	77	3
3	1,74	115	5
4	1,30	153	6
5	1,04	192	8
10	0,52	383	16
20	0,26	767	32
30	0,17	1150	48
40	0,13	1533	64
50	0,10	1917	80
100	0,05	3833	160

Tab.7.4: Breakthrough times for the pilot test

8. Inter-well tracer test implementation

The implementation of the tracer test requires the following steps: pre-job preparation, tracer preparation, tracer injection and sampling. The implementation chapter is divided into the Pilot-Tracer-Test and the FBA-Tracer-Test.

8.1 Pilot-Tracer-Test - Rhodanit

8.1.1 Pre-job preparation

It is very important to maintain a steady state during the test so that arrival data for the tracer(s) are not influenced. Injector shut-downs, workovers and pump changes should be avoided during the test period. As a matter of fact, it is not possible to comply these conditions for the whole test period. Therefore, it is of great importance to list all interruptions with date and duration during the test period separately to include them in later interpretations.

8.1.2 Tracer preparation

The soild Ammoniumthiocyanat must be dissolved in formation water. For that reason two 10m^3 tanks must be prepared at the wellside to dissolve 500 kg Ammoniumthiocyanat in each tank. This 5%-NH_4SCN Solution can then be injected.

8.1.3 Tracer injection

Basically the injection of tracers can be divided into two categories:

- Continuous injection and
- Slug injection.

In continuous injection, the tracer is injected continuously into the water by a dosing pump to achieve a constant tracer concentration in the fluid stream. In slug injection the entire tracer batch is injected at once. Due to simplicity reasons and less field equipment needed it was decided to inject both tracers as a slug.

8.1.4 Sampling

There are three main points which should be considered:

- Sampling points

Samples should be taken directly from the well-head. The fact that several flowlines are already gathered before the separator, make a sampling at the separator impossible.

- Sampling method

Production fluids should be filled in a 1 liter plastic bin. Separation of the fluids is done in the laboratory. Well name and date should immediately be stated on the sample to avoid a mix-up.

- Sampling frequency

As already mentioned in chapter 7.4 the sampling frequency is a function of the estimated breakthrough time. The review of probable breakthrough-times resulted in the following sampling schedule:

- Regular sampling

Wells in the area of interest (appendix D – Fig.D.1), where tracer breakthrough is expected are included in ‘regular sampling’.

Well	Initial Sampling-Rate
GA-057-A	2 samples/week
GA-013	2 samples/week
GA-001	2 samples/week
GA-085	2 samples/week
GA-002-A	2 samples/week
GA-086	2 samples/week
GA-010-A	2 samples/week
GA-037	2 samples/week
GA-016	2 samples/week
GA-005a	2 samples/week
GA-078	2 samples/week
GA-077	2 samples/week
GA-058	2 samples/week

Tab.8.1: Well for ‘Regular sampling’

- Occasional sampling

Wells which are located slightly outside the eastern boarder of the tracer prospect are sampled occasionally to evaluate the sealing properties of fault F4.

Well	Initial Sampling-Rate
GA-026	2 samples/month
GA-080	2 samples/month
GA-083	2 samples/month
GA-087	2 samples/month
GA-008-A	2 samples/month

Tab.8.2: Well for ‘Occasional sampling’

8.1.5 Future Work

- Checking the compatibility of the tracer with other chemicals used in the Gaiselberg Field
- Determination of the solubility of Ammoniumthiocyanat in formation water: The fact that other ions are present in the formation water can significantly reduce the solubility of Ammoniumthiocyanat. To avoid a precipitation it is necessary to determine the solubility of Ammoniumthiocyanat in formation water. For that reason weighted Ammoniumthiocyanat should continuously be added to 1 liter of formation water until a precipitation can be observed.
- The fact that Ammoniumthiocyanat reacts endothermic with water makes it necessary to determine the magnitude of this effect with formation water to avoid failures. For that reason 50 g of Ammoniumthiocyanat should be dissolved in 1 liter formation water. The temperature should be measured before and after the dilution of Ammoniumthiocyanat. If the experiment shows that the temperature of the water significantly decreases, it is necessary to heat up the water before the Ammoniumthiocyanat is added.
- Purchase of 1 liter plastic bottles
- Preparation of tanks
- Preparation of tracer-sample stock
- Preparation of data-sheets for the sampling procedure

8.2 Multiple Tracer Test - FBA

8.2.1 Pre-job preparation

For the multiple FBA tracer test the same applies as for the pilot-tracer-test (chapter 8.1.1).

8.2.2 Tracer preparation

The preparation of FBA tracers is a specialized area and is therefore done by the service company IFE.

8.2.3 Tracer injection

The entire injection procedure is performed by the service company IFE. The injection equipment is provided by the IFE.

8.2.4 Sampling

Basically it can be said that concerning sampling points and method, the same applies as for the Pilot-Test.

The experience gained in the Pilot-Tracer-Test should improve the handling of samples and, first and foremost, the sampling frequency, therefore the results of the Pilot-Test must be bided.

8.2.5 Future Work

- Purchase of 1 liter plastic bottles
- Evaluate recycling of FBA-tracer
- Preparation of tracer-sample stock
- Preparation of data-sheets for the sampling procedure
- Checking the compatibility of the tracer with other chemicals used in the Gaiselberg Field

9. Tracer Test Analysis Methods

Basically the analysis methods can be classified in three categories:

- qualitative
- analytical
- numerical

The simplest method is the qualitative one and is also the most common technique used in petroleum industry.[21] On the other hand the numerical simulation is the most complex one.

All Tracer Tests, used for that survey, are listed in Appendix C.

9.7.1 Qualitative Analysis

Figure 9.1 shows that the qualitative analysis is with 61% the most common one in petroleum industry. This method records arrival and non-arrival of the tracer(s) at the production wells. Although it is simple it provides unambiguous information about the reservoir continuity and barriers.[36], [37]

Nevertheless, it is simple, failures can happen if the sampling is not properly designed.

The non recovery of a tracer due to reaction with the reservoir rock can also be misinterpreted as a flow barrier. As already previously mentioned the interaction with the reservoir rock and/or fluids can lead to a delay of tracer recovery. If the durability of the tracer project is shorter than the delay, the non arrival during the sampling period could be misinterpreted as a flow barrier. [21]

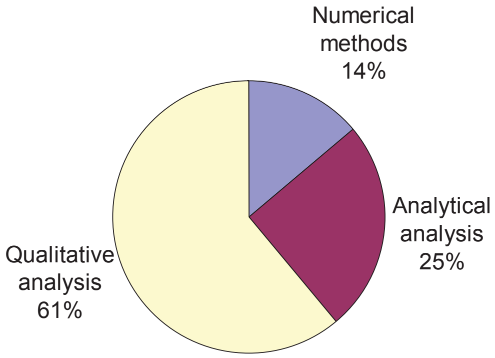


Fig.9.1: Tracer test analysis methods used in inter-well tracer tests in petroleum industry

9.7.2 Analytical Analysis

The first semi-analytical model was proposed by Brigham and Smith[38] in 1965. This model predicts tracer breakthrough times and peak concentrations at producers in a five-spot. In this model a radial flow pattern from the injector to the producer is assumed. The publication of this model made the analytical analysis of inter-well tracer tests more widespread.

A following paper by Brigham and his co-worker Abbaszadeh[39] developed the Brigham model further which was published in 1984. The Brigham- Abbaszadeh[39] model is based on the assumption that the tracer moves through the formation through convective and dispersive forces and arrives at the producers according to the streamlines. These streamlines are generated by the geometry of the flow pattern. The tracer arriving at the producer is diluted by water arriving under other streamlines. Both models handle heterogeneity by dividing the reservoir into a subset of homogenous layers. The injected water is spread among the layers with the respective conductivity (kh). In the layers the tracer moves independently but mix at the well bore of the producer for the tracer response curve. Equally a Dykstra-Parson can be used to generate pseudo-layers to handle the heterogeneity.[22]

Tang[29] extended Brigham’s model that it can also handle partitioning tracers. Currently, it is the main analytical method in petroleum industry.[21]

Figure 9.1 shows that in 25% of the reviewed cases the analytical method found applicability.

9.7.3 Numerical Modeling method

The reservoir heterogeneity strongly influences the flow pattern within the reservoir and hence the production of hydrocarbons and water. To evaluate the influence of the heterogeneity the flow of the tracer can be simulated. Especially powerful computers nowadays make mathematical modeling and simulation possible. Unlike the analytical method the numerical method is very accurate, however, also the most time consuming one.

The numerical modeling of tracer flow involves the simulation based on finite-difference or streamlines.

Only 14% of the used techniques are numerical methods to evaluate the tracer flow.

9.7.4 Applicability to the Gaiselberg Field

Analytical methods are based on simplifications concerning reservoir parameters and conditions. Due to the complexity of the Gaiselberg Field these assumptions do not adequately describe the reservoir. An analytical analysis of the tracer test can therefore be excluded.

Due to the reasons already mentioned in chapter 2, a simulation of the tracer test is not reasonable in the Gaiselberg Field.

Only a qualitative analysis of the tracer test in the Gaiselberg Field will lead to expedient results.

10. Injector Measurements

10.1 Scope of measurements

As a matter of fact, it is essential to know, before a tracer test is performed, where the water is injected. In the Gaiselberg Field many injectors are perforated in more than one layers or even horizons. As already mentioned the reservoir properties of the Gaiselberg Field can only be stated with big uncertainties.[40] Acidizing, without diverters, is only done if difficulties emerge to inject the produced water. All reasons mentioned above make it impossible to quantitatively allocate the surface injection rate to several perforations. Due to the fact that it is not possible to make a quantitative decision with a temperature log a MLT (Mini Logging Tool) with a spinner was used. The MLT includes four sensors to provide data on pressure and temperature with a piezo-resistive sensor, flow rate with the spinner and an electromagnetic casing collar locator (CCL). The sensors and the memory are able to capture 10 values per second and a total of 500.000 values per run.

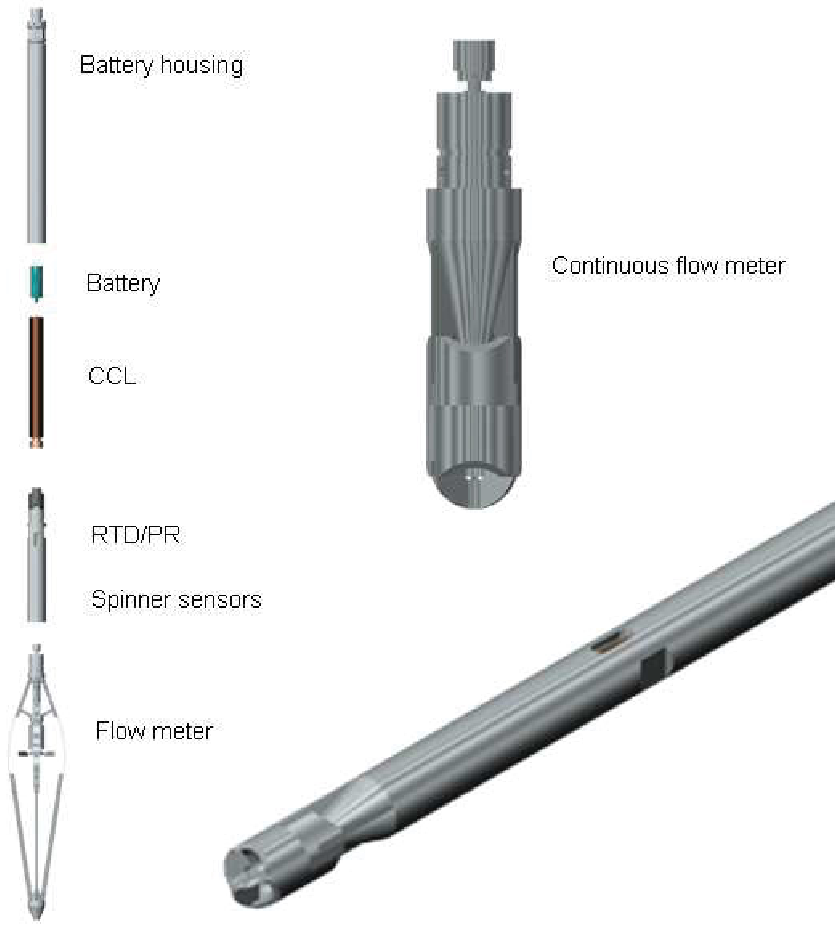


Fig.10.1: MLT-Tool [41]

10.2 Candidate Selection

Due to the fact that a quantitative allocation was the target only injectors which inject in more than one layer were taken into account. One basic condition of the measurement program was to avoid the use of a work over rig. This made it impossible to log GA-022 and GA-043 because the tubing covers the perforations in both cases.

10.3 Principle of the spinner measurements

With the well shown in figure 10.2, perforated in horizon A and B, the principle can easily be explained. During the whole test the injector is always put on stream. If the spinner is located at point one, below both perforations, theoretical no spinner response will be recorded because all of the water has gone into horizon A and/or B. Practically even there turbulences can occur which cause the spinner to rotate a bit. At point two the spinner is rotated only by the water which is injected into perforation A. If the spinner is located at point three, it is rotated by the water injected into A and B – in other words it is rotated by the total flow rate of the injector. If the spinner is located directly in the perforation the response is decreased by the fact that also radial flow is present. The proportions of the spinner response of point 1, 2 and 3 can then be used to allocate easily the total flow rate to the two horizons. Due to the fact that only the proportions of the spinner response are used for the allocation it is of no importance if the spinner measurements are recorded while the tool is moving or just taking point measurements at essential points (in the example 1,2 and 3). The manufacturer of the tool used in the Gaiselberg Field advises to measure while running in at a constant speed. Due to the fact that no 'ideal' speed was advised different speeds were tested.

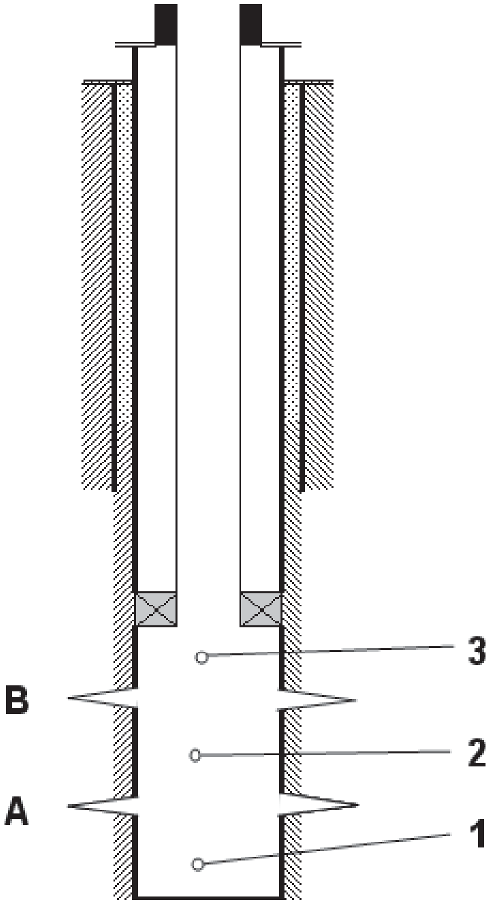


Fig.10.2: Principle of the Spinner measurements

10.4 Spinner results

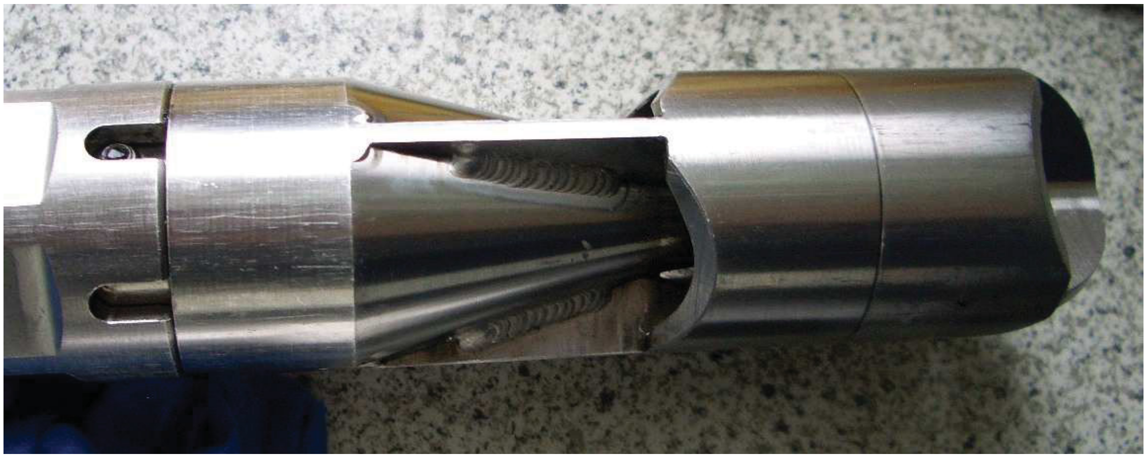
Table 10.1 shows the MLT spinner program in chronological order.

GA-040	Temperature	with Injection
	Spinner - Down	10m/min
		20m/min
		40m/min
		60m/min
	Spinner - Up	10m/min
		20m/min
		40m/min
		60m/min
GA-035	Temperature	after shut-in
		with Injection
	Spinner - Down	5m/min
		20m/min
		40m/min
		60m/min
		80m/min
	Spinner - Up	5m/min
		20m/min
		40m/min
		60m/min
		80m/min
GA-081	Temperature	after shut-in
		with Injection
	Spinner - Down	60m/min
		80m/min
		100m/min
	Spinner - Up	60m/min
		80m/min
		100m/min
GA-061	Temperature	after shut-in

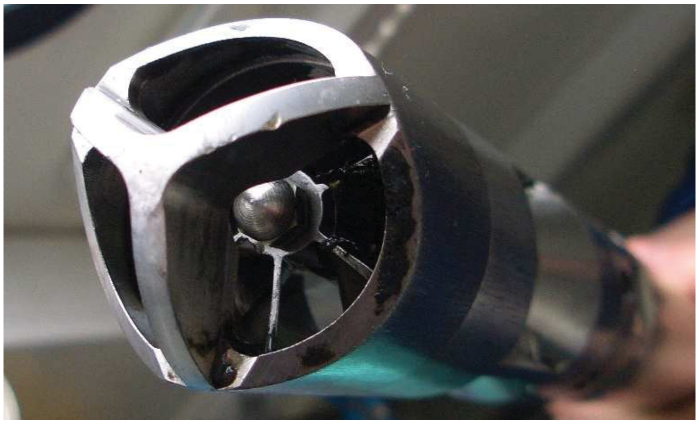
Tab.10.1: Well-Service program

Due to the fact that the MLT was only used for gas wells before no experience with injectors was present. This fact was also essential for the decision on spinner speeds. At the first well (GA-040) the spinner measurements were done with wide range of speeds to get first experiences. The evaluation of the data of GA-040 showed no spinner response at all. Basically it can be said that two reasons could be responsible for that: the significant diameter difference between the spinner (1.5 inch) and the casing (6 5/8 inch) and/or the speed of the spinner tool itself. The significant diameter difference can cause the MLT to be eccentric and therefore lay on the casing - a laminar velocity profil has a significant decrease near the boundaries which can cause the spinner not to rotate. Investigation showed that in all cases (GA-040, GA-035 and GA-081) the flow profile is highly turbulent so that the assumption above can be barred. Nevertheless, the MLT can be in a slanted position which will reduce the effective flow to turn the spinner. An analysis of the spinner response curves shows that the speed of the spinner has a significant impact on the results. Higher spinner speeds show a more continuous spinner response although no correlation between the response and the perforations can be observed at all speeds. Due to the fact that the MLT is moved in once against the fluid direction and once with the injected water an effective velocity was calculated to make velocities comparable.

The MLT speed was increased up to 100m/min which is close to the limit of the cable winch, but even there no analyzable results were obtained. Although the spinner speed and the fluid velocity are added, when moving the MLT upwards, less response can be observed. A reason for that can be the smaller fluid intakes at the back-side (Picture10.1).



Picture 10.1: Mini Logging Tool



Picture 10.2: Mini Logging Tool - Front

Picture 10.3: Mini Logging Tool – Back side

It can be concluded that the spinner results of GA-040, GA-035 and GA-81 were not analyzable. This was also the reason that no spinner measurements were done at GA-061. Analyses of the results show that it is high likely that the threshold velocity to turn the spinner, was not reached in those measurements. To use this tool for injector measurements further investigation must be done

10.5 Temperature Measurements

Due to the fact that the spinner results were not meaningful, temperature measurements were performed to get at least qualitative information.

10.5.1 Principle of Temperature Measurements

The monitored temperature along the well-bore can be correlated with the outflow profile of the well.
The injected water has a significant lower temperature, compared to reservoir temperature and will therefore cause temperature changes. Basically it can be said that it will result in an overall cooling of the reservoir. However, the magnitude of the temperature change in injection intervals differs from case to case.
During injection, the heat-flow in non-injection intervals will only be conduction. In injection intervals, however, the heat-flow will be by both, conduction and convection. Injection intervals are therefore much cooler due to the actual flow of water in the formation.[42]

If a well is shut-in, different phenomena occur. The temperature at all points in the wellbore will increase towards the formation temperature at that point. The rates of temperature increase are, however, quite different. The greater heat loss within the injection intervals, due to convection, results in a much longer time for this interval to reach the formation temperature. Therefore, the rate of temperature increase in injection intervals is much lower than in non-injection intervals. At any given time, then, the temperature of the injection interval is always lower than in a non-injection interval. The results are the temperature anomalies developed after the well is shut in.[42]

10.5.1.1 Temperature response during a multi-rate test

In a multi-rate test water is injected with different rates which in turn will cause different injection pressures. If fracs are present, the opening of them under different conditions could be observed. [42]
Injection has also a great affect on temperature profiles. At extremely high rates (theoretically infinite rate), the injection fluid will hardly have no time to exchange heat with the formation, which will result in a nearly constant temperature profile. In reality, however, injection rates are lower and thus heat will be exchanged between the formation and the injected fluid.

The measurements in the Gaiselberg Field were only performed at the normal operating rate.

10.5.2 Results of temperature measurements

All graphs can be seen in Appendix E.

10.5.2.1 GA-040

Due to the fact that GA-040 is not a first choice candidate for the tracer test and due to the time limitation of the well service it was decided that the temperature will only be measured during injection.

Event I
The fact that the temperature is nearly constant in the first perforation interval indicates, that most of the water will be injected in that interval.

Event II
Below the first perforation interval the temperature starts to increase gradually until a depth of about 1343 m a where a constant slope is developed. Between 1355 m and 1363 m a cold event can be observed. This cold event is congruent with the upper half of the second perforation interval (1357m-1370m). Because of the smaller magnitude it can be said that significant less water is injected in that interval. It seems to be that no water is injected in the lower half of the second perforation interval.

Event III
Beginning at a depth of about 1343 m the temperature starts to increase with a constant slope till a depth of about 1405m where the slope starts to decrease again. The upper two-thirds of the third perforation interval do not take any water. The decrease of slope, beginning at the lower third of the third perforation till the fifth perforation interval, clearly indicates zones of water injection. Because of the lower magnitude it can again concluded that only a little amount of water is injected in those intervals below 1405m.

10.5.2.2 GA-035

Event I
A gradual temperature decrease can be seen in figure E.1 at the depth of the first perforation interval. The small increase after this period indicates the zone between the first and the second perforation interval.

Event II

At the depth of the second perforation interval a typical temperature anomaly of an injection interval can be observed. In the temperature profile which was recorded during injection (fig.E.2) no difference between the first and the second perforation interval is cognizable.

Only with the temperature profile of the shut-in injector it can be concluded that most of the water is injected in the second perforation interval. In the first perforation interval only a small amount of water, if at all, is injected.

Event III

The significant decrease of slope of temperature in the zone of the third perforation interval indicates a zone of water injection, even if it is marginal in comparison with the second perforation interval. The event can be observed in both profiles.

Events marked with a circle

First it was believed that those events were caused by variations in temperature of the injected water only, but the profile of the shut-in injector showed the same events. These events could for example indicate small casing leaks. Another reason for those coolings could also be an event behind the casing – for example a water-bearing layer. Also flow behind the casing in case of a bad cement job can be present.

10.5.2.3 GA-081

Event I

The distinctive cooling event at a depth of about 1182 m indicates a zone of water injection. Due to the sharp increase of temperature below 1182 m it can be concluded the most of the water is injected only in the upper part of the first perforation interval.

Event II

Even though the formation temperature is higher in a greater depth, the water injected into the second perforation interval, cooled this interval even more than in the first perforation interval. This clearly indicates that most of the water in this well is injected in this perforation.

Event III

The fact that the temperature does not increase after the second perforation interval can basically have two reasons: the top layer (second perforation) has already cooled the layer underneath or communication behind the casing. About a meter below the top of the third perforation a significant increase of temperature can be observed. This indicates that only in the upper part of this perforation water is injected.

For events marked with a circle the same as for GA-035 applies.

10.5.2.4 GA-061

Due to the fact that GA-061 is not a first choice candidate for the tracer test and due to the time limitation of the well service, it was decided that only the temperature after shut-in will be measured (Figure E.4).

Event I
The significant cool event at a depth of about 1120m indicates, that already cemented perforations at that depth are again partially open.

Event II
The gradual temperature increase with depth has a significant abnormality between about 1207m and 1337m can be observed. It could indicate a casing lack in the lower part (about 1297m-1320m) which also influences the temperature above due to a bad cementing job. The black straight line indicates the geothermal gradient.

Event III
The constant temperature increase below 1337 m indicates that no water is injected into the perforations which start below 1347,7 m

10.6 Conclusions and Best Practice

The interpretation of the temperature log clearly indicates that some perforation intervals take significant more water than others. A layer where the water has already broken through has less resistance and therefore is favorable for the injected water. On the other hand zones where less or no water is injected could indicate oil bearing layers, with lower permeability and more resistance. It is important to state at this point that this fact could also be due to a higher skin of that interval.

It is very likely that the causes for the failed spinner measurement are too small velocities. Basically two facts corroborate this assumption: It was observed that the higher the effective spinner velocity the better the spinner response. The other fact is that the MLT has already been successfully used for measuring gas wells – the velocity is magnitudes higher there. Although, the manufacturer states that the MLT is applicable for producers as well as for injectors it seems to be that the blades of the spinner are designed rather for higher velocities and therefore rather for gas-producer applications than for injector applications. A more accurate statement needs more investigation (see chapter 11).

The temperature measurement was a success even though no quantitative statement was possible. The temperature profile of an injector on-stream makes it possible to determine the main zones of injection very quickly. Although it was also observed that misinterpretations can happen without the information of the temperature profile of the shut-in injector (GA-035). The temperature profile of a shut-in injector makes it possible to even interpret small ‘cold events’. This can be explained with the fact that the temperature difference between the cold event and the indigenous formation increases with shut-in time and becomes therefore more significant.

Future temperature measurements should always be done during injection and after shut-in of at least twelve hours to make a precise qualitative statement possible.

11. Recommendations

- SIMULATION

A reservoir simulation of the Gaiselberg Field is not recommended. This results mainly from the large uncertainties of the geological model which are caused by

- the low seismic resolution and
- the outdated fault interpretation.

A complete reinterpretation of the field will easily excess three-man-years. Even a reinterpreted geological model would not lead to a reasonable simulation due to the inaccurate production and missing pressure data. Due to the fact that some wells were perforated in more than one layer and no selective testing was done, the allocation of the produced fluids becomes difficult. Additionally only a few well tests were performed to get information about the reservoir pressures.

Although a complete reinterpretation of the model is not reasonable due to the reasons mentioned above, in future the Gaiselberg-team should be supported by the geological department.

- SALINITIES

No data-base with salinity measurements has been available until now. Insistent investigation was necessary to find salinity filings because of the different depositing places. None of the data were available electronically which made an analysis nearly impossible. The first digitalization was done in ‘Microsoft Excel’ due to simplicity reasons. One important recommendation was to develop a salinity data-base in ‘Prod-Com’ to make analyses in the Schlumberger Software ‘Oil field manager’ possible. Especially, gross rate, water cut, well salinity and water-flood salinity over time makes an easy characterization of the well possible.

Nevertheless the analyses of the salinity data showed only limited success due to the very low data frequency. For future analyses it is essential to increase the data frequency of the salinity measurements to guarantee good interpretation results. In contrast to the current status in which salinity measurements are only performed on request, they should be included in the daily routine in the future. This could be realized by adding the salinities to the daily report (Sondenwärterbericht). This would on the one hand side recollect the importance of the salinity measurements and on the other hand make a continuous ‘data transfer’ to ‘Prod Com’ possible. Nevertheless, it is of great importance to sensitize, all people involved, for the new approach with salinities to guarantee good results.

- INJECTION DATA

Not only the monitoring of the whole water-flooding project is important but also the monitoring of each individual well to guarantee a successful oil recovery. For a water-flood project it is essential to evaluate the performance of each and every single injector. The Hall Plot, described in chapter 3.1, is an easy-to-use technique and a very cost effective tool to evaluate the performance of an injector. Therefore it is indispensable to record the injection rate and the well head pressure at frequent intervals. Several injectors are provided with water through a star-shaped piping. Only the cumulative volume is measured on a daily basis. With the help of a mobile flow-meter an allocation factor is calculated every year to distribute the daily cumulative volume to the injectors. This circumstance will not allow creating a reliable Hall Plot. For that reason permanent flow-meters have to be installed at every injection well.

Again it is very important to make the data-recording to a daily routine by adding the injection rate and the well head pressure on the daily report (Sondenwärterbericht).

- INJECTOR MEASUREMENT

Temperature Measurements

The temperature measurement was a success even though no qualitative statement was possible. The temperature profile of an injector on-stream makes it possible to determine the main zones of injection very quickly. Although it was also observed that misinterpretations can happen without the information of the temperature profile of the shut-in injector. The temperature profile of a shut-in injector makes it possible even to interpret small ‘cold events’. For this reason it is highly recommended to measure the temperature of injectors in both states in the future.

Spinner Measurements:

The spinner measurements at the injectors were not successful, but are essential to evaluate quantitative allocation factors for different horizons. Further investigation is recommended and therefore, two questions have to be clarified before future spinner measurements are done:

- Is the Spinner applicable for injector measurements?
- Does the deviation of the tool in the casing influence the measurements?

It is very likely that the causes for the failed spinner measurement are too small velocities. Basically two facts corroborate this assumption: It was observed that the higher the effective spinner velocity the better the spinner response. The other fact is that the MLT has already been successfully used for measuring gas wells – the velocity is magnitudes higher there. Although, the manufacturer states that the MLT is applicable for producers as well as for injectors it seems to be that the blades of the spinner are designed rather for higher velocities and therefore rather for gas-producer applications than for injector applications.

Due to the significant diameter difference between the MLT and the casing, a deviation of the tool during a run is unavoidable. A simulation could show the impact of this deviation on the measurements.

For both purposes it is necessary to disassemble the spinner to make a measurement of the propeller geometry possible.

- TRACER

A review of the surveillance methods (chapter 2-6) shows that only a tracer test could give reasonable results. The other techniques are limited in their use mainly because of data frequency and data quality reasons.

Waterflooding, as a second recovery process, greatly depends on the knowledge of reservoir continuity and uniformity regarding fluid transmissibility. Techniques such as seismic, geological deposition and reservoir simulation provide useful information on the feasibility of a secondary recovery project. Other techniques like material balance, WOR-Plot and salinity surveys can provide valuable information on the performance of individual wells and on the performance of the entire water-flood project. However, the actual fluid distribution of the reservoir fluid transmissibility can only be evaluated with the help of an interwell tracer test. Tracers can render information which is almost impossible to obtain with other techniques such as identifying flow paths and breakthrough times. Tracer information compared to other techniques is reliable and unambiguous.

Due to the relatively small production of the Gaiselberg Field and the significantly above-average recovery factor a costly (see Appendix F) FBA-tracer test is fraught with risk. For that reason it is recommended to perform a pilot-tracer-test first to gain knowledge in the following points:

- Tracer

- sample handling
- breakthrough times, hence sampling frequency
- sealing properties of faults (especially fault F4), hence selecting possible monitoring wells
- ‘tracer response curve’, hence information about the dilution volume.

- Tracer test interpretation:

- effect of new water-flooding strategies
- areas with by-passed oil

The gained knowledge can significantly reduce the costs of the FBA-tracer test and can give meaningful information if such a multiple tracer test is reasonable or not in the Gaiselberg Field.

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Appendix A: Material Balance

A.1 Mathematical Derivation [1]

VRR is defined as:

$$VRR = \frac{Injected\ \mathrm{Re}servoir\ Volume}{\mathrm{Pr}oduced\ \mathrm{Re}servoir\ Volume} \qquad \text{Eq.1}$$

The instantaneous VRR can then be calculated as follows:

$$Inst.VRR = \frac{B_w \cdot i_w}{B_o q_o + B_w q_w + \left(q_g - q_o R_s\right) B_g} \qquad \text{Eq.2}$$

To understand the waterflood performance the cumulative instantaneous VRR are plotted against time. If VRR approaches unity the injection process replaces exactly the volume gained due to production.

After the material balance principle:

$$DDI + SDI + CDI + WDI = 1 \qquad \text{Eq.3}$$

$$DDI = \frac{NE_o}{HCV}$$

$$SDI = \frac{N\,m\,E_g}{HCV}$$

$$E_o = B_t - B_{ti} \qquad \text{Eq.4}$$

$$B_t = B_o + B_g\left(R_{si} - R_s\right) \qquad \text{Eq.5}$$

$$\therefore HCV = N_p\left[B_t + B_g + \left(R_p - R_{si}\right)\right] \qquad \text{Eq.6}$$

$$E_g = \frac{B_{ti}}{B_{gi}}\left(B_g - B_{gi}\right) \qquad \text{Eq.7}$$

$$E_{fw} = B_{ti}\left(1+m\right)\frac{S_{wi}\,C_w + C_f}{1-S_{wi}}\left(P_i - P\right) \qquad \text{Eq.8}$$

$$WDI = \frac{W_e - W_p\,B_w + W_i\,B_{wi}}{HCV} \qquad \text{Eq.9}$$

To simplify Equation 9 the following assumptions are met:

- under saturated oil reservoir with solution gas drive
- no gas cap (m=0)
- no segregation of gas in the reservoir as a secondary gas cap
- no encroachment of water (W_e=0)
- no mobile water in the reservoir to produce (W_p=0)

$$WDI = I - \left(DDI + CDI\right)$$

Rearranged:

$$\frac{W_i\,B_{wi}}{Total\ Voidage} = 1 - \frac{NE_t}{Total\ Voidage} = VR \qquad \text{Eq.10}$$

$$VRR = 1 - Expansion\ of\ reservoir\ fluid\ and\ rock \qquad \text{Eq.11}$$

$$E_t = E_o + E_{fw} \quad where \quad E_t = f\left(P_i - P\right),\ represents\ the\ total\ \exp ansion\ factor.$$

Because of production the reservoir pressure will decrease with time and hence reservoir fluid and rock will expand. Therefore the injected water should fill this created voidage to gradual increase the average reservoir pressure - P tends to P_i

$$\lim_{P \to P_i}\left(E_t\right) = 0 \qquad \text{Eq.12}$$

In this case a complete re-pressurization of the reservoir is achieved.

- **Abbreviations**

DDI = Depletion Drive Index

SDI = Segregation Drive Index

CDI = Compressible Drive Index

HCI = Hydrocarbon Voidage

WDI = Water Drive Index

B_w = Formation volume factor of water (rb/stb) at current reservoir pressure

B_o = Formation volume factor of oil (rb/stb) at current reservoir pressure

B_g = Formation volume factor of gas (rb/scf) at current reservoir pressure

B_t = Total formation volume factor of hydrocarbon phase (rb/stb)

R_s = Solution gas oil ratio

R_i = Gas oil ratio under initial conditions

R_p = Cumulative gas oil ratio

N = Stock tank oil initially in place in reservoir (stb)

N_p = Stock tank oil produced (stb)

W_p = Cumulative stock tank water produced (stb)

W_e = Reservoir volume of aquifer water encroached (rb)

W_i = Cumulative volume of water injected (stb)

S_{wi} = Initial water saturation (fraction)

C_w = Compressibility of water (psi^{-1})

C_f = Compressibility of formation rock (psi^{-1})

P_i = Initial reservoir pressure (psi)

P = Current reservoir pressure (psi)

E_o = Expansion of the oil and its originally dissolved gas

E_g = Expansion of gas cap

E_{fw} = Expansion of the connate water and reduction in the pore volume due to expansion of the reservoir rock

E_f = Expansion factor total

$$m = \frac{initial\ hydrocarbon\ volume\ of\ gas\ cap}{initial\ hydrocarbon\ volume\ of\ the\ oil}$$

‘m’ is defined under initial conditions and is constant

q_o = Oil production rate (stb/d)

q_g = Gas production rate (scf/d)

q_w = Water production rate (stb/d)

i_w = Water injection rate (stb/d)

Appendix B: Salinity

B.1 Salinity survey

B.1.1 Overview of the results

11th Sarmat

Well	Salinity-NaCl	Salinity Difference[mg/l]	Trend	Current Value	Classification	Class
	[mg/l]	[mg/l]				
GA-037	16884	1822	no	yes	NO TREND BUT PRESENT VALUE	2
GA-051	13831	4875	no	yes	NO TREND BUT PRESENT VALUE	5
GA-019	15500	3206	constant	no	NOT INFLUENCED IN THE PAST	4
GA-074	only initial		no	no	NO STATEMENT POSSIBLE	-

12th Sarmat

Well	Salinity-NaCl	Salinity Difference[mg/l]	Trend	Current Value	Classification	Class
	[mg/l]	[mg/l]				
GA-001	14534	4172	dev., constant	yes	NOT INFLUENCED	not influenced
GA-058	19120	414	constant	no	INFLUENCED IN THE PAST	1
GA-072	18700	6	approach	no	INFLUENCED IN THE PAST	1
GA-077	15749	2957	approach	yes	INFLUENCED	3
GA-083	17868	838	approach	yes	INFLUENCED	1
GA-057-(A)	18648	58	approach	yes	INFLUENCED	1
GA-008-A	15281	3425	approach	yes	INFLUENCED	4
GA-010-(A)	13294	5412	constant	yes	NOT INFLUENCED	not influenced
GA-006	13500		constant	no	NOT INFLUENCED IN THE PAST	not influenced
GA-013-(A)	16615	2091	approach	yes	INFLUENCED	3
GA-007	17200	1506	approach	no	INFLUENCED IN THE PAST	2
GA-018	14201		no	no	NO STATEMENT POSSIBLE	-
GA-026	17509	1197	approach	yes	INFLUENCED	2
GA-087	16222	2484	no	yes	NO TREND BUT PRESENT VALUE	3
GA-012	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-044	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-082-A	8800	9906	no	no	NO STATEMENT POSSIBLE	-

Tab.B.1: Overview of the results – 11th Sarmat and 12th Sarmat

13th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-078	14898	3808	constant	yes	NOT INFLUENCED	not influenced
GA-085	14500		constant	yes	NOT INFLUENCED	not influenced
GA-008-A	13500 - 14000		constant	no	NOT INFLUENCED IN THE PAST	not influenced
GA-058	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-077	14000		constant	no	NOT INFLUENCED IN THE PAST	not influenced
GA-010-A	15200	3506	no	no	NO STATEMENT POSSIBLE	-
GA-080	15907	2799	no	yes	NO TREND BUT PRESENT VALUE	3

14th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-005-A	15000	3706	constant	yes	NOT INFLUENCED	not influenced
GA-002-A	15563	3143	no	yes	NO TREND BUT PRESENT VALUE	4
GA-016	14500	4206	no	no	NO STATEMENT POSSIBLE	5

Tab.B.2 : Overview of the results – 13th Sarmat and 14th Sarmat

15th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-058-A	13600	5106	no	yes	NO TREND BUT PRESENT VALUE	6
GA-082-B	12436	6270	no	yes	NO TREND BUT PRESENT VALUE	7
GA-040	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-005-A	14493	4213	no	no	NO STATEMENT POSSIBLE	-
GA-080	14000	4706	no	no	NO STATEMENT POSSIBLE	-
GA-016	13000	5706	no	no	NO STATEMENT POSSIBLE	-
GA-057	15000	3706	no	no	NO STATEMENT POSSIBLE	-
GA-087	15670	3036	no	no	NO STATEMENT POSSIBLE	-
GA-037	16164	2542	no	no	NO STATEMENT POSSIBLE	-

16th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-079	16400	2306	approach	no	NO STATEMENT POSSIBLE	-
GA-016	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-090	23156	4450	consatant	yes	NOT INFLUENCED	not influenced
GA-060	20584	1878	no	yes	NO TREND BUT PRESENT VALUE	2
GA-082-A	18058	648	no	no	NO STATEMENT POSSIBLE	1
GA-046	13500		consatant	no	NOT INFLUENCED IN THE PAST	not influenced
GA-080	17000	1706	no	no	NO STATEMENT POSSIBLE	-
GA-059	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-012	only initial		no	no	NO STATEMENT POSSIBLE	-

Tab.B.3: Overview of the results – 15th Sarmat and 16th Sarmat

17th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-007	20337	1631	no	no	NO STATEMENT POSSIBLE	-

18th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-089	23000		no	no	NO STATEMENT POSSIBLE	
GA-036	20625	1919	constant	no	NOT INFLUENCED IN THE PAST	not influenced
GA-015	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-034	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-059	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-091	25737	7031	no	yes	NOT INFLUENCED	>6

Tab.B.4: Overview of the results - 17th Sarmat and 18th Sarmat

19th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-035	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-059	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-022	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-043	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-040	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-042	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-060	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-027	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-017	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-052	19105	399	approach	yes	INFLUENCED	1
GA-015	20500	1794	approach	no	INFLUENCED IN THE PAST	2
GA-002	20500	1794	no	no	NO STATEMENT POSSIBLE	2
GA-090	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-089	only initial		no	no	NO STATEMENT POSSIBLE	-

20th Sarmat

Well	Salinity-NaCl [mg/l]	Salinity Difference[mg/l] [mg/l]	Trend	Current Value	Classification	Class
GA-034	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-035	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-042	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-059	only initial		no	no	NO STATEMENT POSSIBLE	-
GA-007	only initial		no	no	NO STATEMENT POSSIBLE	-

Tab.B.5: Overview of the results – 19th Sarmat and 20th Sarmat

B.2.2 Diagrams

Only Diagrams with a certain trend and a current salinity value are presented here.

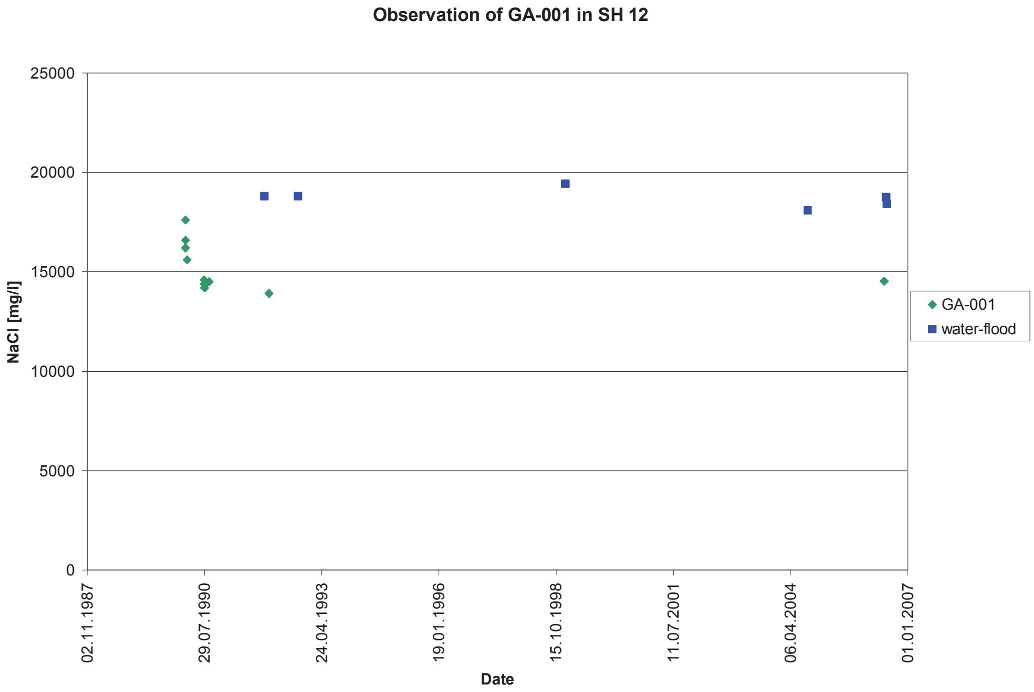

Fig.B.1: Observation of GA-001 in the 12th Sarmat

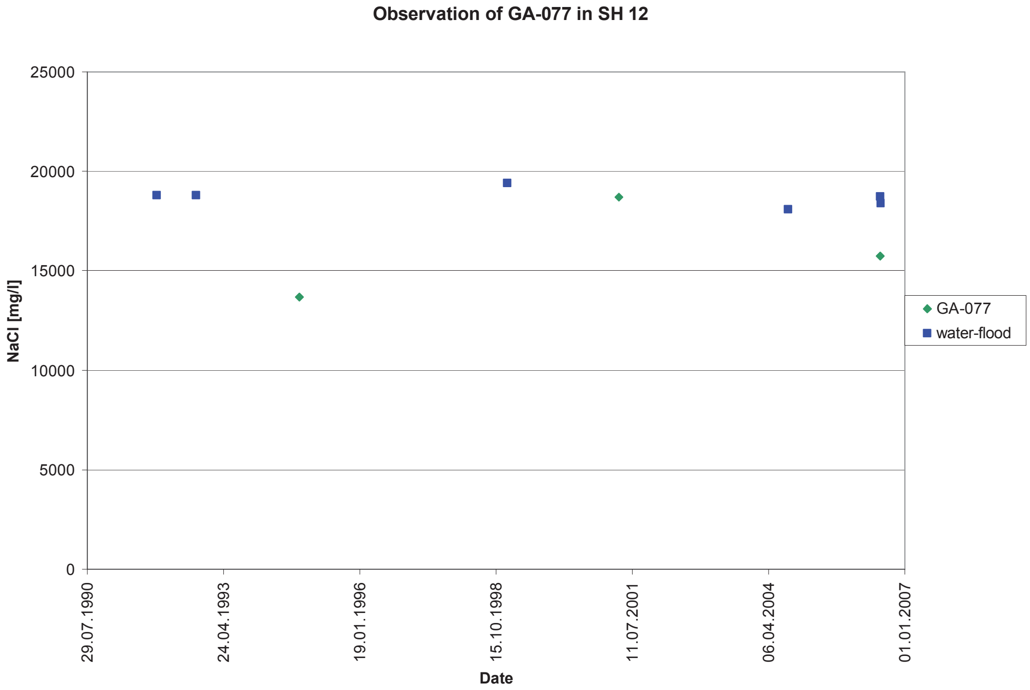

Fig.B2: Observation of GA-077 in the 12th Sarmat

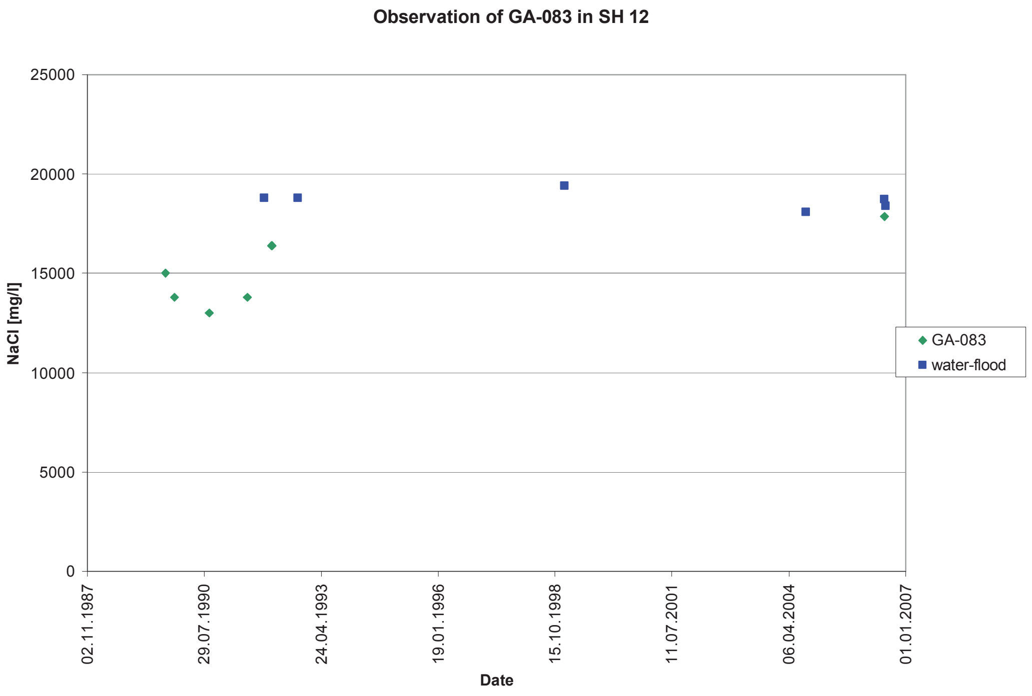

Fig.B.3: Observation of GA-083 in the 12th Sarmat

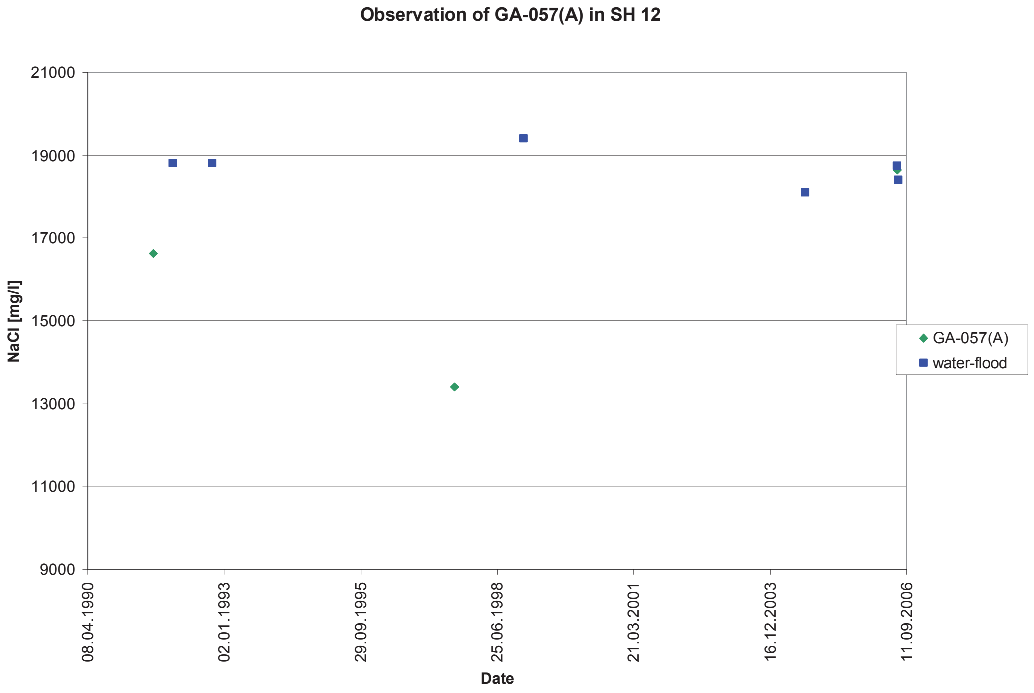

Fig.B.4: Observation of GA-057(A) in the 12th Sarmat

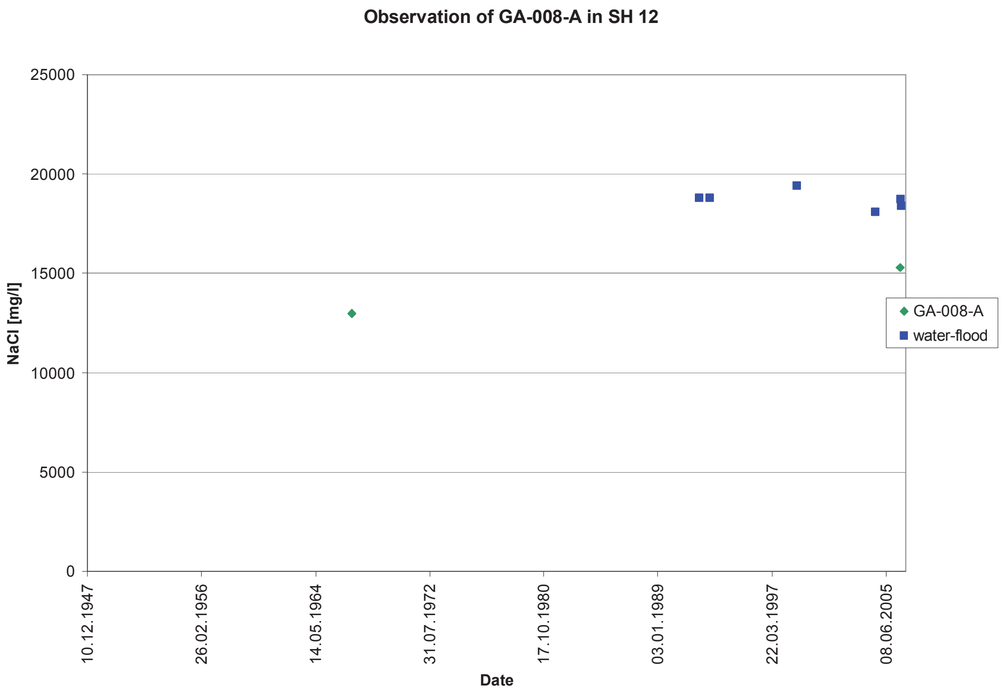

Fig.B.5: Observation of GA-008-A in the 12th Sarmat

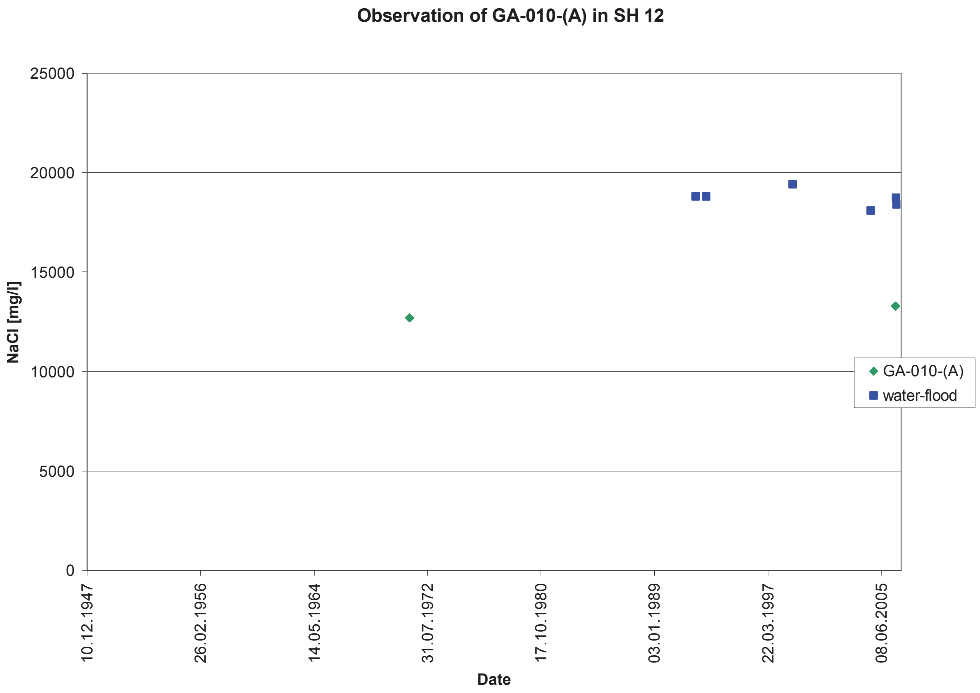

Fig.B.6: Observation of GA-010(A) in the 12th Sarmat

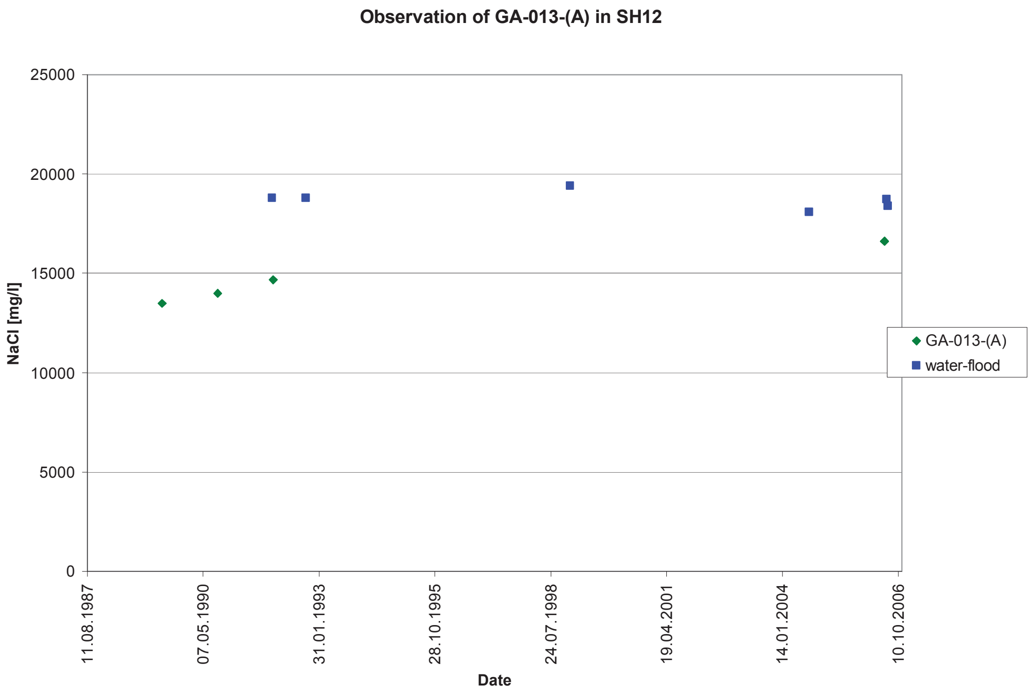

Fig.B.7: Observation of GA-013(A) in the 12th Sarmat

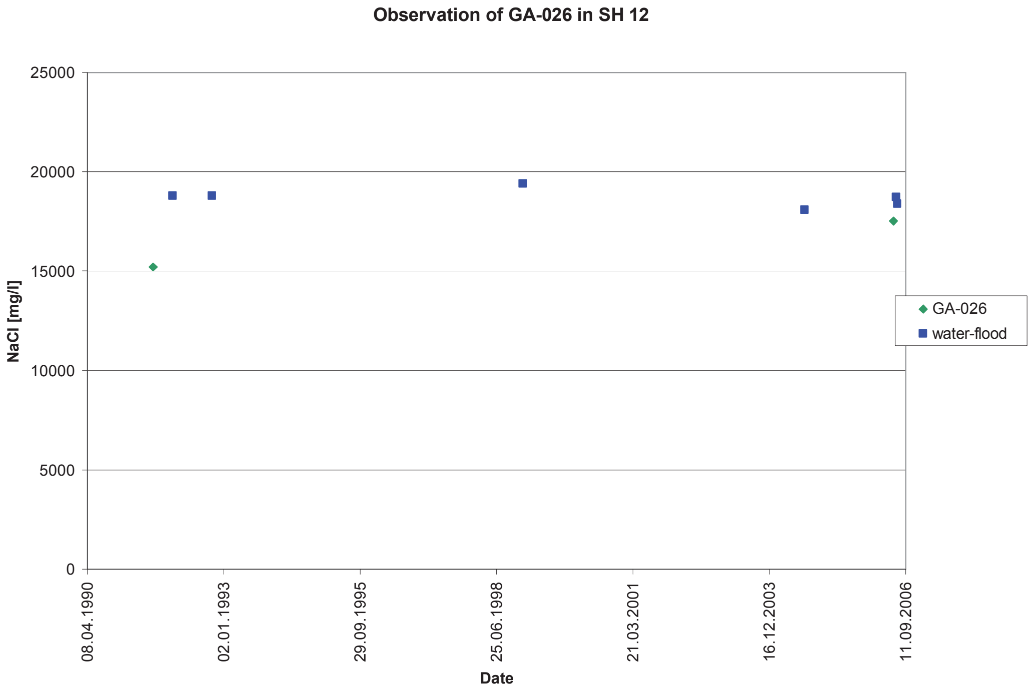

Fig.B.8: Observation of GA-026 in the 12th Sarmat

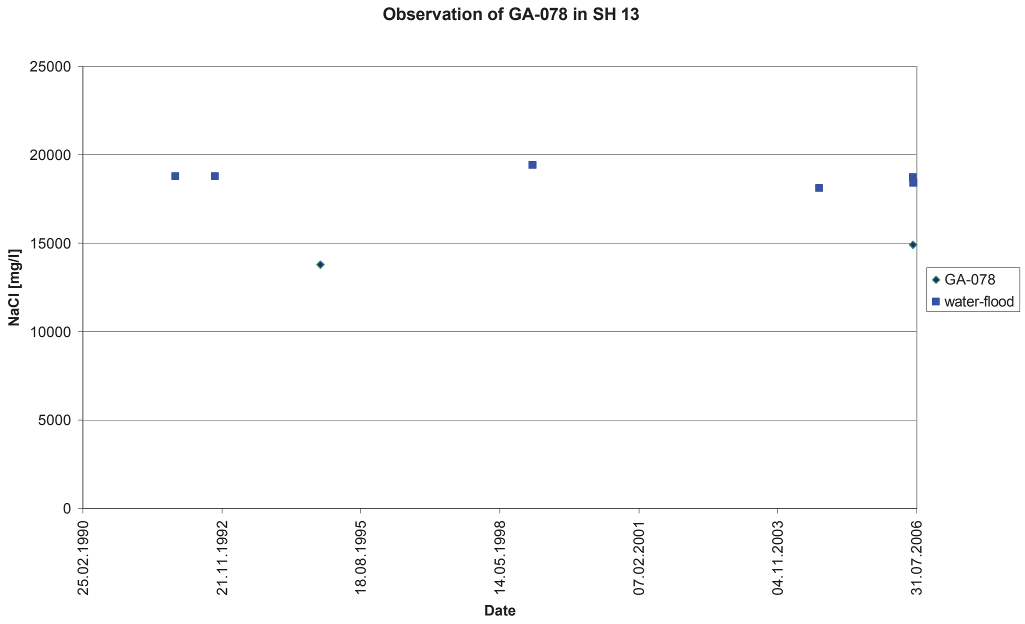

Fig.B.9: Observation of GA-078 in the 13th Sarmat

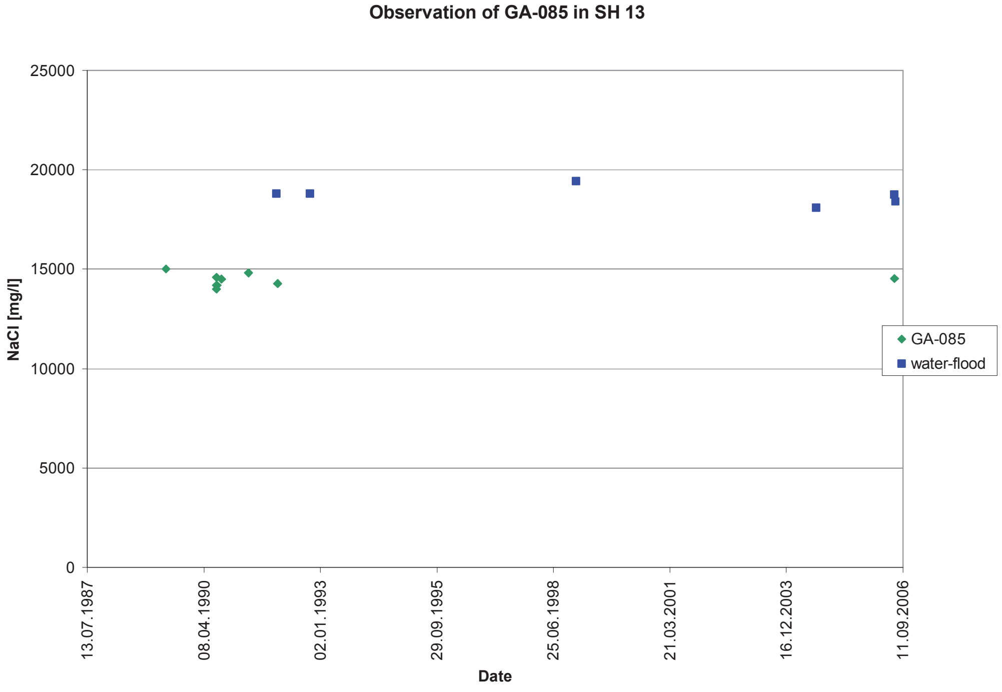

Fig.B.10: Observation of GA-085 in the 13th Sarmat

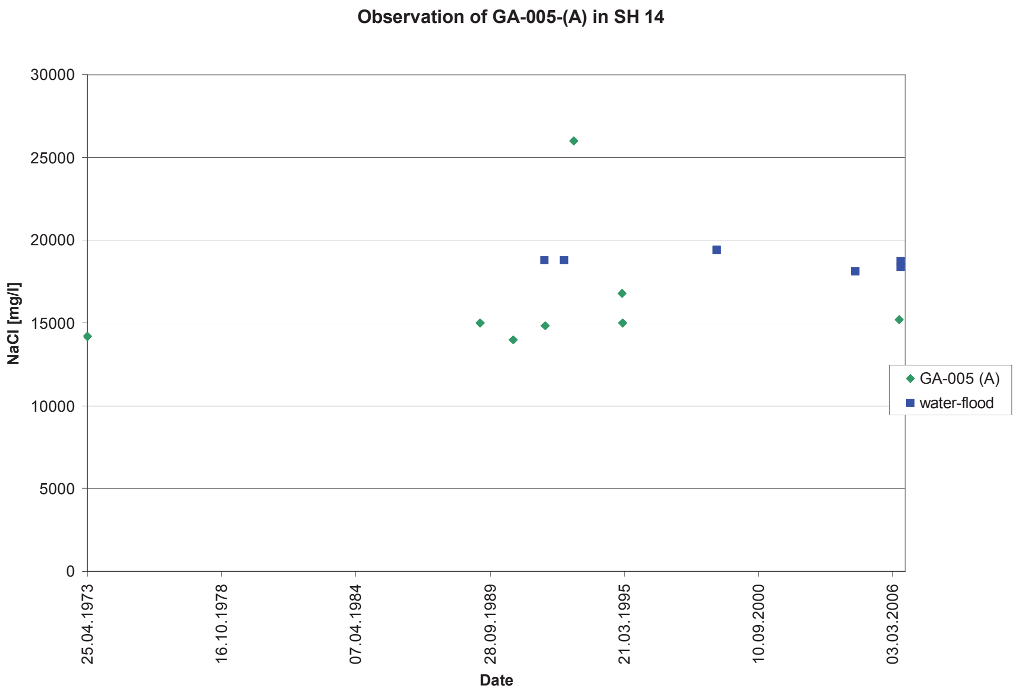

Fig.B.11: Observation of GA-005(A) in the 14th Sarmat

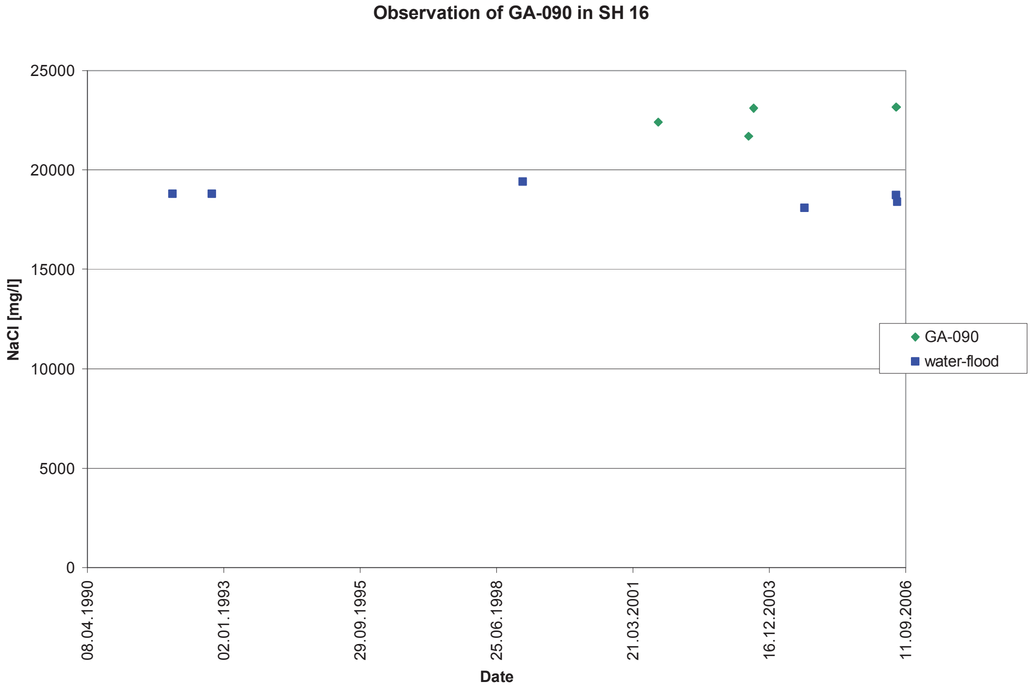

Fig.B.12: Observation of GA-090 in the 16th Sarmat

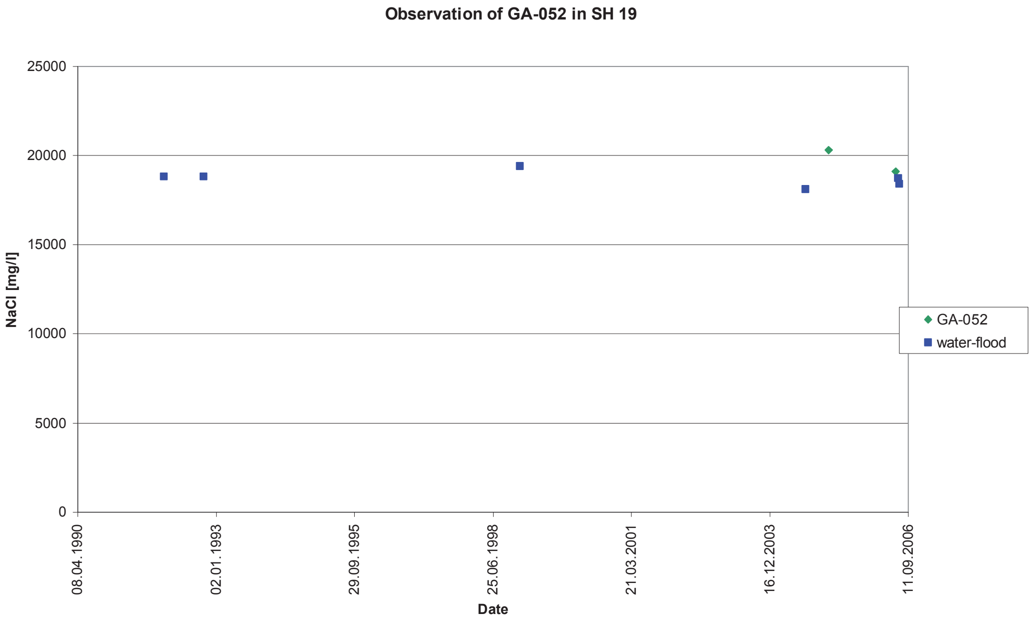

Fig.B.13: Observation of GA-052 in the 19th Sarmat

Appendix C: Inter-Well Tracer Tests

Tracer test fields	Field locations	Tracer classification	Tracer names	Analysis method	Ref.
5-spot from an unnamed field	USA	Water tracer	Ammonium thiocyanate, potassium iodide	Analytical	[38-[39
Arrowhead Grayburg Unit	New Mexico, USA	Water tracer	Neutralized halo-acid, Rhodamine	Qualitative	[10
Big Muddy	Wyoming, USA	Water tracer	Tritiated water, Thiocyanate ion, Ethyl alcohol, Methyl alcohol	Numerical	[44[45
Carmopolis	Brazil	Water tracer	H^3, Florescent, I	Qualitative	[36
Central Part of Mesozoic Chiapas-Tapasco Basin	Mexico	Gas tracer	PMCH	Qualitative	[37
Coalinga	California, USA	Gas tracer	Methane	Qualitative	[46
Cymric	USA	Gas tracer	Carbon Isotope	Analytical	[47
Eastern Devonian Shale	Ohio, USA	Gas tracer	Nitrogen	Qualitative	[48
Ekofish	North Sea	Water tracer	Tritium water, I-125	Qualitative	[49
El Furrial	Venezuela	Water tracer, gas tracer	SCN, IPA, HTO	Qualitative	[50
Fairway	USA	Gas tracer	Kr^{85}	Qualitative	[51
Fenn-Big Valley	USA	Water tracer	Tritiated water, Co-60, Eu-152, Eu-154, Cs-134, Cs-137	Qualitative	[52
Fordoche	Louisiana, USA	Gas tracer	Kr^{85}, Tritiated Hydrogen, Tritiated ethane, Tritiated methane	Qualitative	[53
Golden Spike D3 "A"	Alberta, Canada	Gas tracer	SF$_6$, F12, F13B1	Analytical	[27, [54
Gullfaks	North Sea, Europe	Water tracer; Gas tracer	Tritiated water; PMCH, PMCP, SF$_6$	Qualitative; Numerical	[55-[56
Hueneme	California, USA	Water tracer	Nitrate, thiocyanate, methane, ethanol and tritium	Qualitative	[57
Jauf Reservoir in Ghawar	Saudia Arabia	Water tracer	Radioactive tracers	Qualitative	[58, [59
Jobo	Venezuela	Gas tracer	Kr-85, Ch3T, 14CH4	Qualitative	[60, [61
Judy Creek	Alberta, Canada	Water tracer; Gas tracer	Tritiated water, Tritiated C5-C8	Qualitative	[62, [54
Lagocinco	Maracaibo Lake Basin, Venezuela	Water tracer; Gas tracer	4-FBA, 2-FBA, 3&4diFBA; PMCP, PMCH	Qualitative	[63
Levelland Unit	West Texas, USA	Water tracer	Tritiated water, Ammonium nitrate, Potassium iodide, Ammonium thiocyanate	Qualiative	[64
Little Buffalo	Wyoming, USA	Water tracer	Kr^{85}, H^3, Tritiated Ethane	Analytical	[65
Means San Andreas unit	Texas, USA	Water tracer	Tritiated water	Qualitative	[66

MCA unit of Maljamar	New Mexico, USA	Water tracer	Tritium water	Qualitative	[67
Mitsue	Alberta, Canada	Gas tracer	Tritiated methane, tritiated ethane, tritiated butane, fron-11, Kr^{85}, SF_6	Qualitative	[68
Niitsu	Japan	Water tracer	NaCl, NH_4SCN, KI, KNO_2	Analytical; Numerical	[69
North Sea	North Sea	Water tracer	TH	Qualiative; Analytical	[70-[71
North West Fault Block of Prudhoe Bay	Alaska, USA	Water tracer	Co-57, Co-60, C-14, Tritiated water	Analytical	[72
Oakridge	California, USA	Water tracer	Nitrate, bromide, thiocyanate and methane	Qualiative	[57
Painter Reservoir	Wyoming, USA	Gas tracer	SF6, Freon-113	Qualitative	[73
Pubei	Xinjiang, China	Gas tracer	C_6F_{12}	Analytical	[74-[75
Rainbow Keg River \`B\` Pool	Alberta, Canada	Gas tracer	Tritiated Methane, tritiated ethane, tritiated butane	Qualitative	[76, [77
Ranger	Texas, USA	Water tracer	Tritium, NaSCN, IPA, TBA, Co-57, Co-58, Co-60	Analytical; Numerical; Streamline	[78, [79-[83
Redwater	Alberta, Canada	Water tracer	HTO, Cs, Co	Qualitative	[84
Salt Creek	Wyoming, USA	Water tracer	KI, HTO, IPA, NO_3^-,CNS^-	Qualitative	[64
Seria	Brunei	Water tracer	Co-60	Analytical	[85
Shallow Oil Zone	California, USA	Gas tracer	Perfluorocarbon tracers	Qualitative	[86
Sleipner	North Sea, Norway	Gas tracer	PMCH, PDMCB	Qualitative	[55
Snorre	North Sea, Norway	Water tracers; Gas tracers	HTO, 4-FBA, NaSCN, S14CN-; PDMCB, SF_6, 1,3-PDMCH	Qualitative; Numerical	[87-[89
South Midway Sunse	California, USA	Water tracer	Chloride, Bromide, Boron, and Sillica	Qualitative	[90
South Swan Hill Unit	Canada	Water tracer, gas tracer	Tritiated water, Tritiated Ethane, Kr^{85}	Analytical	[64-[65
Strawn	North Texas, USA	Water tracer	No data available	Qualitative	[91
West Sumatra	Montana, USA	Water tracer	C-14, Co-57, Co-60, tritiated water	Analytical	[92

Tab.C.1: Interwell Field Tracer Tests Included In Study

USA	Canada	Europe	Venezuela	Brazil	Brunei	China	Japan	Mexico	Saudi Arabia
23	6	5	3	1	1	1	1	1	1

Tab.C.2: Geographic Location Of Reviewed Interwell Tracer Tests

Appendix: D Tracer amount calculations

To account for safety it is assumed that the tracer dilutes in the entire part 1, independent in which horizon of part 1 it is injected. Because of the higher MDL of Rhodanit this assumption could not be taken for the Rhodanit-Pilot-Test – the dilution in the entire part 1 would lead to an enormous amount of tracer. Therefore, a limited area and only the horizon were GA-088 is perforated (12th Sarmat) were taken in account for the calculation. The area is bordered in the west through the Gaiselberg fault and in the east through fault XXX, which are assumed to be sealing.

According to the reservoir engineer of the Gaiselberg Field the water saturations were uniformly set to 0.9 to account for safety in the dilution volumes.

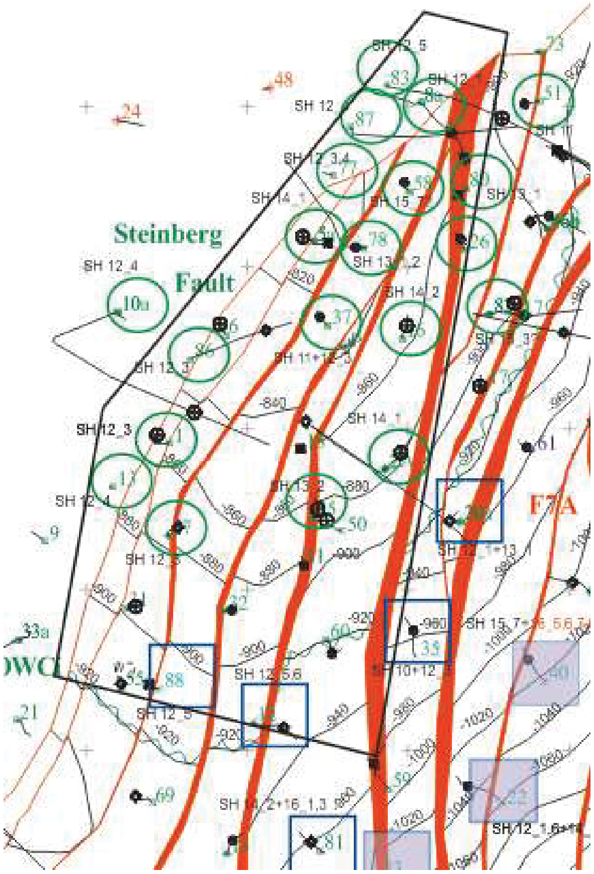

Fig.D.1: Area of the Pilot-Tracer-Test

D.1 Pilot Tracer Test – GA-088 – Rhodanit

Horizon	Thickness	Porosity	Water Sat.	Area	Dilution Volume
	[m]	[-]	[-]	[m²]	[m³]
SH 12/1	3	0,31	0,9	277500	232268
SH 12/2+3	3	0,31	0,9	277500	232268
SH 12/4	4	0,31	0,9	277500	309690
SH 12/5	5	0,23	0,9	277500	287213
SH 12/6	5	0,28	0,9	277500	349650
				Sum	1411088

Tab.D.1: Dilution Volumes – GA-088

Injector	Dilution Volume	Correction F.	MDL	Saftey	Active Tracer-amount	Tracer-Amount
	[m³]	[-]	[kg/m³]	[-]	[kg]	[kg]
GA-088	1411088	1	0,00005	10	705,54	**924,51**

Tab.D.2 : Tracer quantities for GA-088

D.2 Multiple Tracer Test – GA-012 – FBA

				Distance to		**Dilution Volume**	
Horizon	**Thickness**	**Porosity**	**Water Sat.**	GA-083	GA-010A	GA-083	GA-010A
	[m]	[-]	[-]	[m]	[m]	[m³]	[m³]
SH 11	5	0,29	0,9	800	560	2623858	1285691
SH 12/1	3	0,31	0,9	800	560	1682888	824615
SH 12/2+3	3	0,31	0,9	800	560	1682888	824615
SH 12/4	4	0,31	0,9	800	560	2243851	1099487
SH 12/5	5	0,23	0,9	800	560	2080991	1019686
SH 12/6	5	0,28	0,9	800	560	2533380	1241356
SH 13/1	3,6	0,31	0,9	800	560	2019466	989538
SH 13/2	5,5	0,31	0,9	800	560	3085295	1511795
SH 13/3	3	0,31	0,9	800	560	1682888	824615
SH 14/1	4	0,31	0,9	800	560	2243851	1099487
SH 14/2	17	0,32	0,9	800	560	9843992	4823556
SH 15/1	2	0,31	0,9	800	560	1121926	549744
SH 15/2+3	7	0,31	0,9	800	560	3926739	1924102
SH 15/4+5	3	0,31	0,9	800	560	1682888	824615
SH 15/6	2	0,31	0,9	800	560	1121926	549744
SH 15/7	4,1	0,31	0,9	800	560	2299947	1126974
SH 15/8	4	0,31	0,9	800	560	2243851	1099487
SH 16/1+2	12	0,31	0,9	800	560	6731553	3298461
SH 16/3+4	8	0,31	0,9	800	560	4487702	2198974
					Sum	55339883	27116543

Tab.D.3 Dilution Volumes – GA-012

Injector	**Producer**	**Dilution Volume**	**Correction F.**	**MDL**	**Saftey**	**Tracer-amount**
		[m³]	[-]	[kg/m³]	[-]	[kg]
GA-012	GA-083	55339883	1	5,00E-08	10	27,67
	GA-010A	27116543	4	5,00E-08	10	**54,23**

Tab.D.4 : Tracer quantities for GA-012

D.3 Multiple Tracer Test – GA-020A – FBA

				Distance to		**Dilution Volume**	
Horizon	**Thickness**	**Porosity**	**Water Sat.**	GA-083	GA-010A	GA-083	GA-010A
	[m]	[-]	[-]	[m]	[m]	[m³]	[m³]
SH 11	5	0,29	0,9	550	500	1240183	1024945
SH 12/1	3	0,31	0,9	550	500	795428	657378
SH 12/2+3	3	0,31	0,9	550	500	795428	657378
SH 12/4	4	0,31	0,9	550	500	1060570	876504
SH 12/5	5	0,23	0,9	550	500	983593	812887
SH 12/6	5	0,28	0,9	550	500	1197418	989602
SH 13/1	3,6	0,31	0,9	550	500	954513	788854
SH 13/2	5,5	0,31	0,9	550	500	1458284	1205193
SH 13/3	3	0,31	0,9	550	500	795428	657378
SH 14/1	4	0,31	0,9	550	500	1060570	876504
SH 14/2	17	0,32	0,9	550	500	4652824	3845309
SH 15/1	2	0,31	0,9	550	500	530285	438252
SH 15/2+3	7	0,31	0,9	550	500	1855998	1533883
SH 15/4+5	3	0,31	0,9	550	500	795428	657378
SH 15/6	2	0,31	0,9	550	500	530285	438252
SH 15/7	4,1	0,31	0,9	550	500	1087085	898417
SH 15/8	4	0,31	0,9	550	500	1060570	876504
SH 16/1+2	12	0,31	0,9	550	500	3181711	2629513
SH 16/3+4	8	0,31	0,9	550	500	2121141	1753009
					Sum	26156742	21617142

Tab.D.5 Dilution Volumes – GA-020A

Injector	**Producer**	**Dilution Volume**	**Correction F.**	**MDL**	**Saftey**	**Tracer-amount**
		[m³]	[-]	[kg/m³]	[-]	[kg]
GA-020A	GA-083	26156742	1	5,00E-08	10	13,08
	GA-010A	21617142	4	5,00E-08	10	**43,23**

Tab.D.6 : Tracer quantities for GA-020A

D.4 Multiple Tracer Test – GA-035 – FBA

				Distance to		**Dilution Volume**	
Horizon	**Thickness**	**Porosity**	**Water Sat.**	GA-083	GA-010A	GA-083	GA-010A
	[m]	[-]	[-]	[m]	[m]	[m³]	[m³]
SH 11	5	0,29	0,9	675	525	1867962	1130001
SH 12/1	3	0,31	0,9	675	525	1198072	724760
SH 12/2+3	3	0,31	0,9	675	525	1198072	724760
SH 12/4	4	0,31	0,9	675	525	1597429	966346
SH 12/5	5	0,23	0,9	675	525	1481487	896208
SH 12/6	5	0,28	0,9	675	525	1803549	1091036
SH 13/1	3,6	0,31	0,9	675	525	1437686	869711
SH 13/2	5,5	0,31	0,9	675	525	2196465	1328726
SH 13/3	3	0,31	0,9	675	525	1198072	724760
SH 14/1	4	0,31	0,9	675	525	1597429	966346
SH 14/2	17	0,32	0,9	675	525	7008076	4239454
SH 15/1	2	0,31	0,9	675	525	798715	483173
SH 15/2+3	7	0,31	0,9	675	525	2795501	1691106
SH 15/4+5	3	0,31	0,9	675	525	1198072	724760
SH 15/6	2	0,31	0,9	675	525	798715	483173
SH 15/7	4,1	0,31	0,9	675	525	1637365	990505
SH 15/8	4	0,31	0,9	675	525	1597429	966346
SH 16/1+2	12	0,31	0,9	675	525	4792288	2899038
SH 16/3+4	8	0,31	0,9	675	525	3194858	1932692
					Sum	39397241	23832899

Tab.D.7 : Dilution Volumes – GA-035

Injector	**Producer**	**Dilution Volume**	**Correction F.**	**MDL**	**Saftey**	**Tracer-amount**
		[m³]	[-]	[kg/m³]	[-]	[kg]
GA-035	GA-083	39397241	1	5,00E-08	10	19,70
	GA-010A	23832899	4	5,00E-08	10	**47,67**

Tab.D.8: Tracer quantities for GA-035

D.5 Multiple Tracer Test – GA-081 – FBA

				Distance to		**Dilution Volume**	
Horizon	**Thickness**	**Porosity**	**Water Sat.**	GA-083	GA-010A	GA-083	GA-010A
	[m]	[-]	[-]	[m]	[m]	[m³]	[m³]
SH 11	5	0,29	0,9	950	700	3700050	2008891
SH 12/1	3	0,31	0,9	950	700	2373136	1288461
SH 12/2+3	3	0,31	0,9	950	700	2373136	1288461
SH 12/4	4	0,31	0,9	950	700	3164181	1717949
SH 12/5	5	0,23	0,9	950	700	2934522	1593259
SH 12/6	5	0,28	0,9	950	700	3572462	1939619
SH 13/1	3,6	0,31	0,9	950	700	2847763	1546154
SH 13/2	5,5	0,31	0,9	950	700	4350748	2362179
SH 13/3	3	0,31	0,9	950	700	2373136	1288461
SH 14/1	4	0,31	0,9	950	700	3164181	1717949
SH 14/2	17	0,32	0,9	950	700	13881567	7536806
SH 15/1	2	0,31	0,9	950	700	1582090	858974
SH 15/2+3	7	0,31	0,9	950	700	5537316	3006410
SH 15/4+5	3	0,31	0,9	950	700	2373136	1288461
SH 15/6	2	0,31	0,9	950	700	1582090	858974
SH 15/7	4,1	0,31	0,9	950	700	3243285	1760897
SH 15/8	4	0,31	0,9	950	700	3164181	1717949
SH 16/1+2	12	0,31	0,9	950	700	9492542	5153846
SH 16/3+4	8	0,31	0,9	950	700	6328361	3435897
					Sum	78037883	42369598

Tab.D.9 : Dilution Volumes – GA-081

Injector	**Producer**	**Dilution Volume**	**Correction F.**	**MDL**	**Saftey**	**Tracer-amount**
		[m³]	[-]	[kg/m³]	[-]	[kg]
GA-081	GA-083	78037883	1	5,00E-08	10	39,02
	GA-010A	42369598	4	5,00E-08	10	**84,74**

Tab.D.10: Tracer quantities for GA-081

D.6 Multiple Tracer Test – GA-040 – FBA

				Distance to		**Dilution Volume**	
Horizon	**Thickness**	**Porosity**	**Water Sat.**	GA-083	GA-010A	GA-083	GA-010A
	[m]	[-]	[-]	[m]	[m]	[m³]	[m³]
SH 11	5	0,29	0,9	725	660	2154946	1785863
SH 12/1	3	0,31	0,9	725	660	1382138	1145416
SH 12/2+3	3	0,31	0,9	725	660	1382138	1145416
SH 12/4	4	0,31	0,9	725	660	1842850	1527221
SH 12/5	5	0,23	0,9	725	660	1709095	1416374
SH 12/6	5	0,28	0,9	725	660	2080638	1724282
SH 13/1	3,6	0,31	0,9	725	660	1658565	1374499
SH 13/2	5,5	0,31	0,9	725	660	2533919	2099929
SH 13/3	3	0,31	0,9	725	660	1382138	1145416
SH 14/1	4	0,31	0,9	725	660	1842850	1527221
SH 14/2	17	0,32	0,9	725	660	8084763	6700067
SH 15/1	2	0,31	0,9	725	660	921425	763611
SH 15/2+3	7	0,31	0,9	725	660	3224988	2672637
SH 15/4+5	3	0,31	0,9	725	660	1382138	1145416
SH 15/6	2	0,31	0,9	725	660	921425	763611
SH 15/7	4,1	0,31	0,9	725	660	1888922	1565402
SH 15/8	4	0,31	0,9	725	660	1842850	1527221
SH 16/1+2	12	0,31	0,9	725	660	5528551	4581664
SH 16/3+4	8	0,31	0,9	725	660	3685701	3054442
					Sum	45450041	37665708

Tab.D.11: Dilution Volumes – GA-040

Injector	**Producer**	**Dilution Volume**	**Correction F.**	**MDL**	**Saftey**	**Tracer-amount**
		[m³]	[-]	[kg/m³]	[-]	[kg]
GA-040	GA-083	45450041	1	5,00E-08	10	22,73
	GA-010A	37665708	4	5,00E-08	10	**75,33**

Tab.D.12: Tracer quantities for GA-040

Appendix E: Injector Measurements

E.1 Temperature Logs

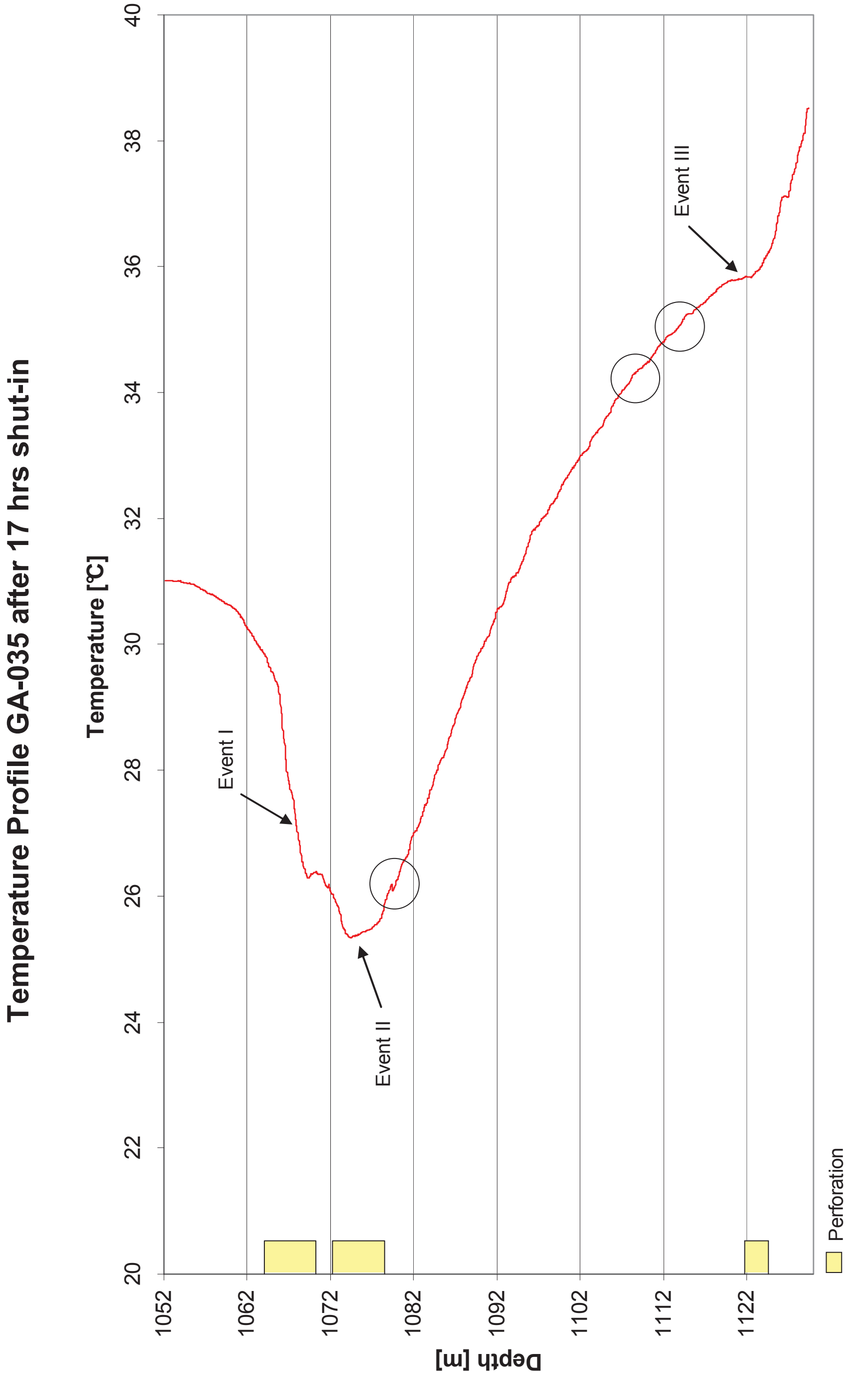

Fig.E.1: Temperature Profile of GA-035 after shut-in

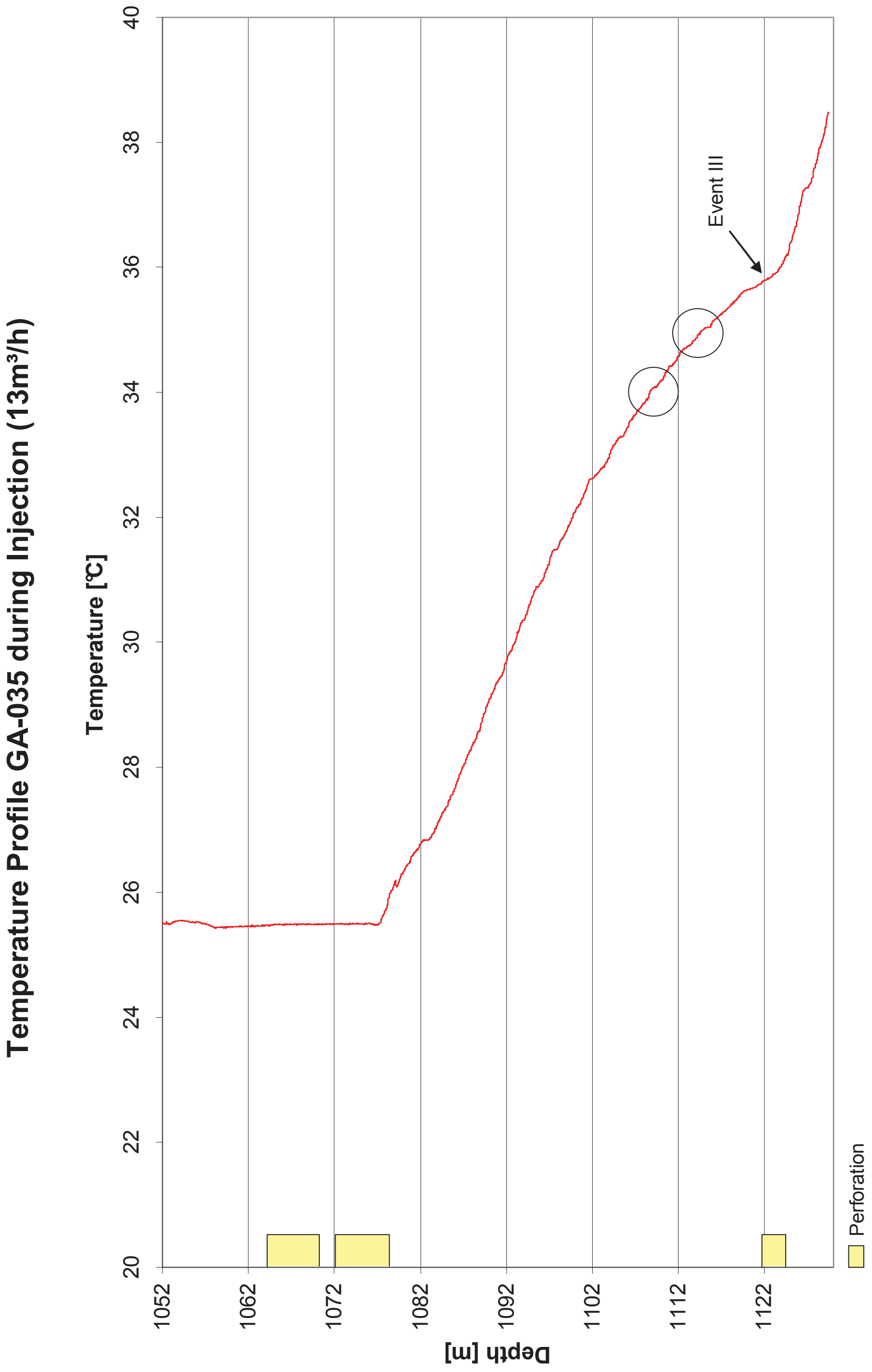

Fig.E.2: Temperature Profile of GA-035 during Injection

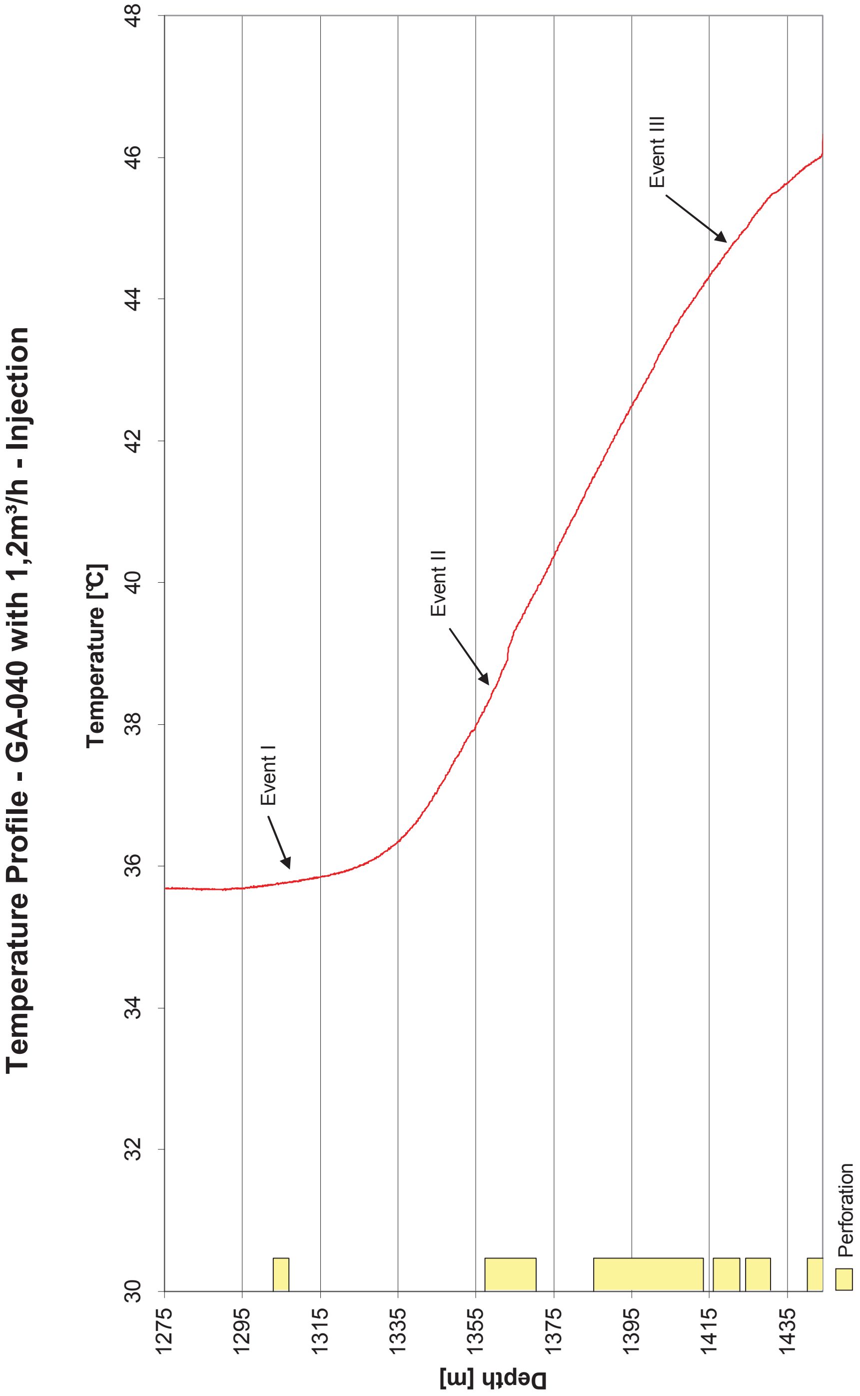

Fig.E.3: Temperature Profile of GA-040 during Injection

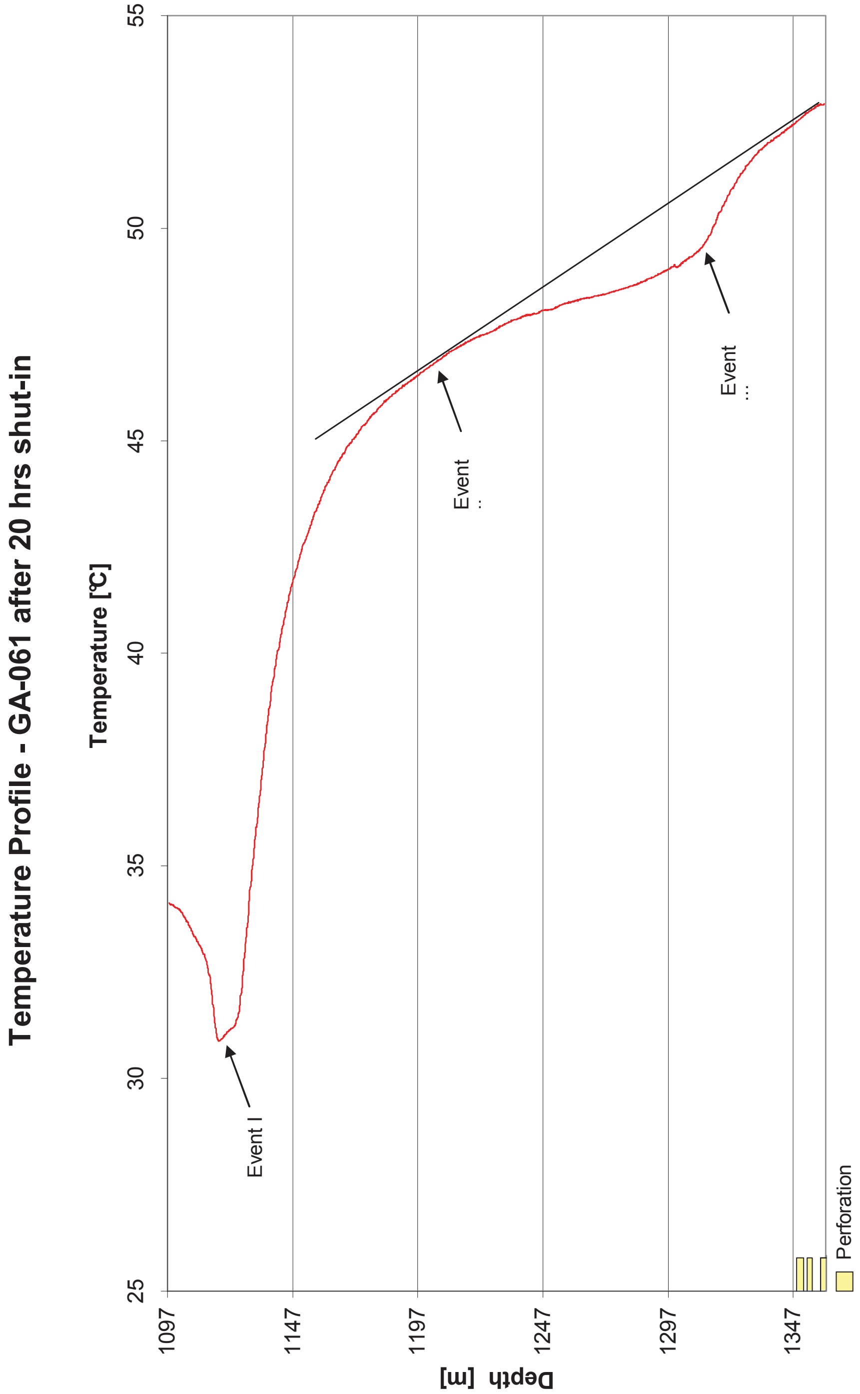

Fig.E.4: Temperature Profile of GA-061 after shut-in

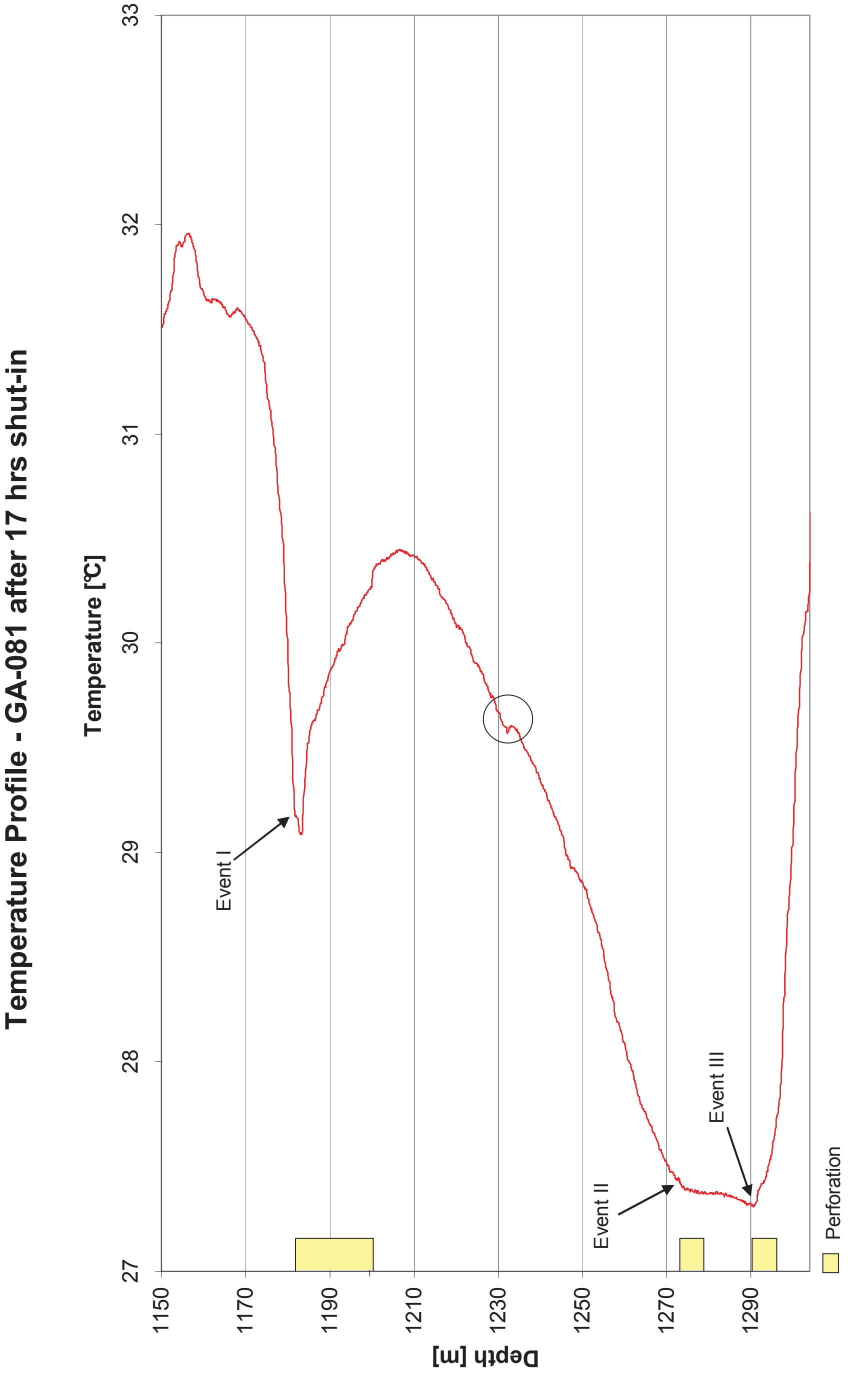

Fig.E.5: Temperature Profile of GA-081 after shut-in

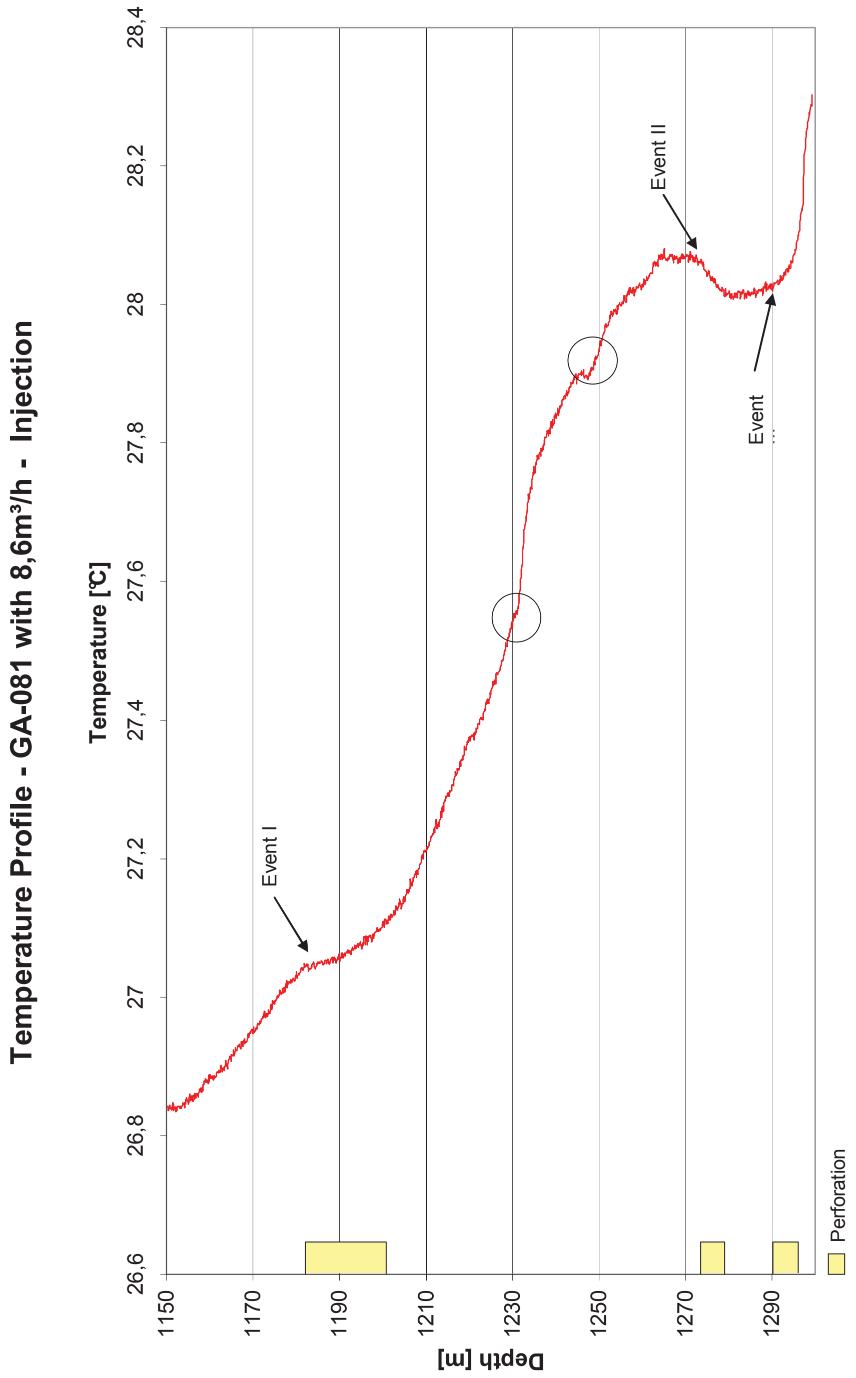

Fig.E.6: Temperature Profile of GA-081 during Injection

E.2 Spinner Logs

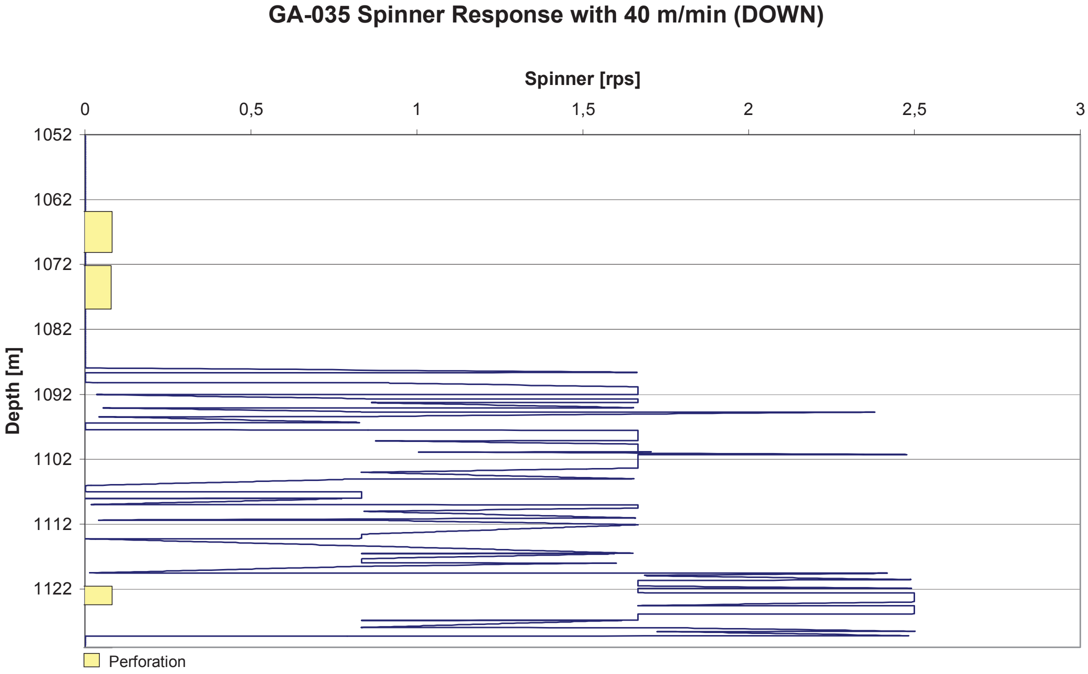

Fig.E.7: GA-035 Spinner Response with 40m/min (DOWN)

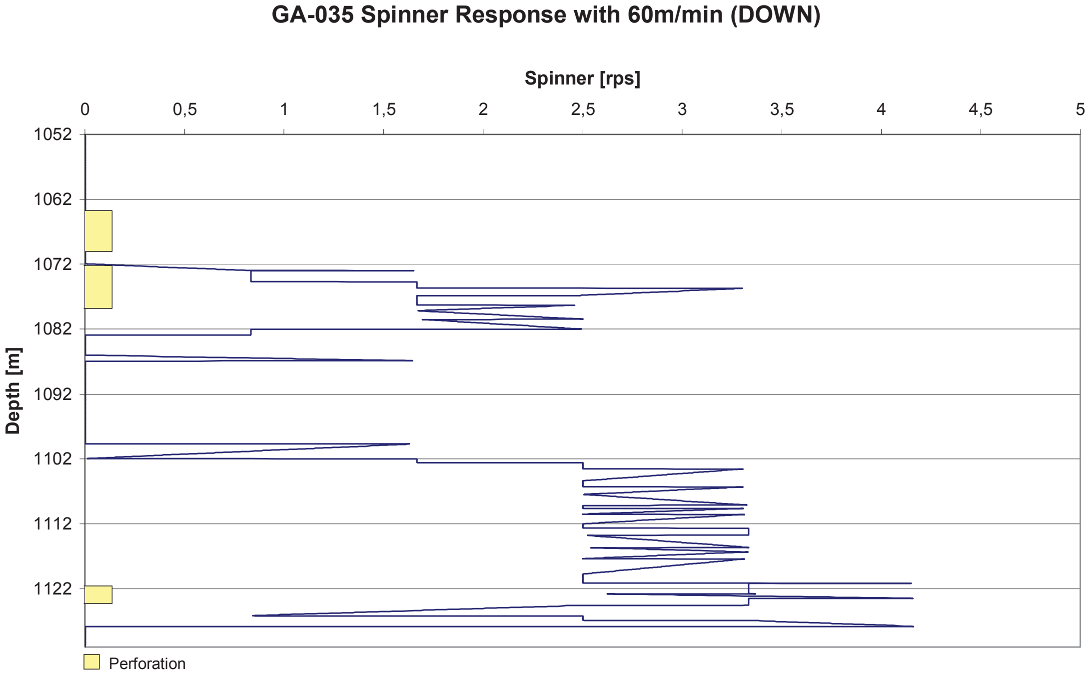

Fig.E.8: GA-035 Spinner Response with 60m/min (DOWN)

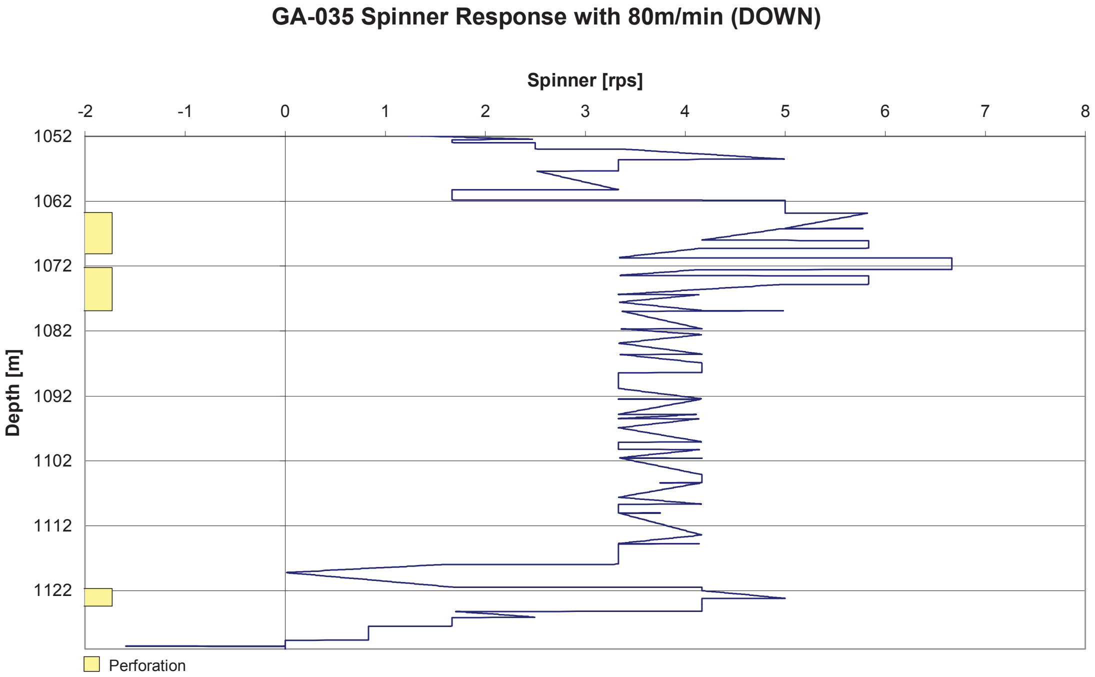

Fig.E.9: GA-035 Spinner Response with 80m/min (DOWN)

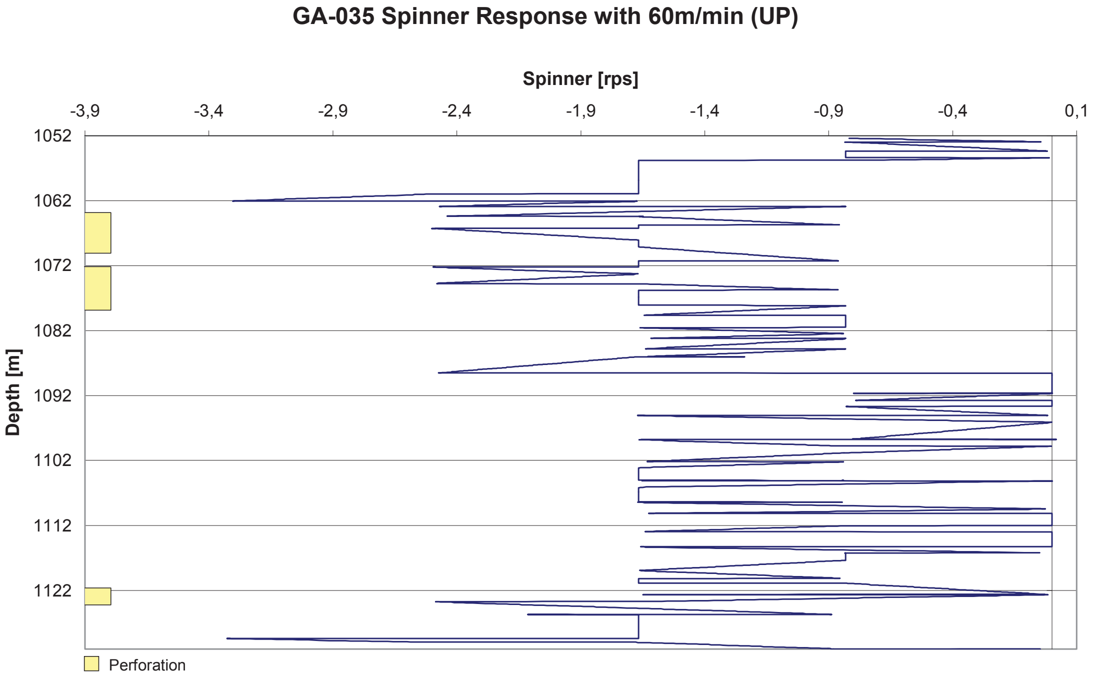

Fig.E.10: GA-035 Spinner Response with 60m/min (UP)

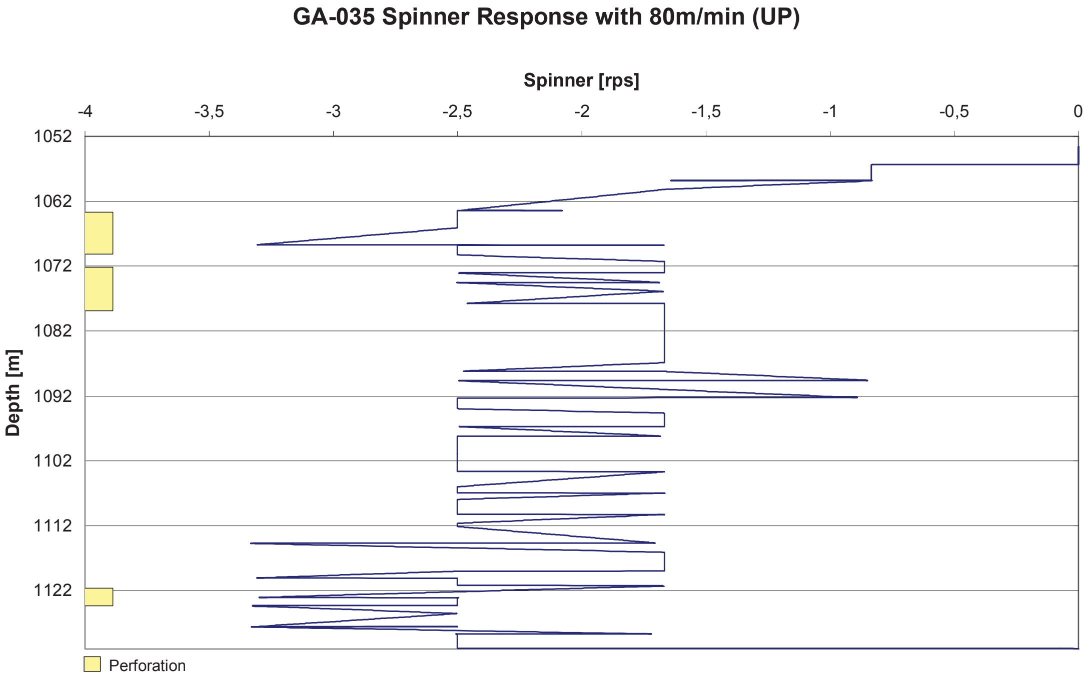

Fig.E.11: GA-035 Spinner Response with 80m/min (UP)

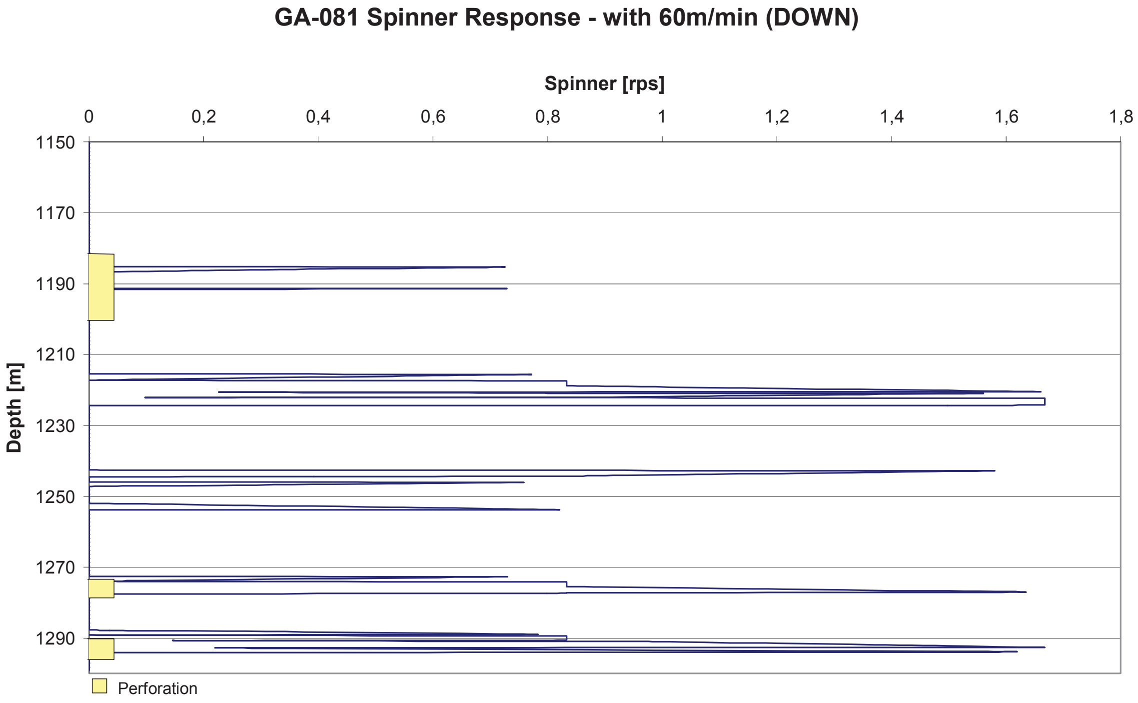

Fig.E.12: GA-081 Spinner Response with 60m/min (DOWN)

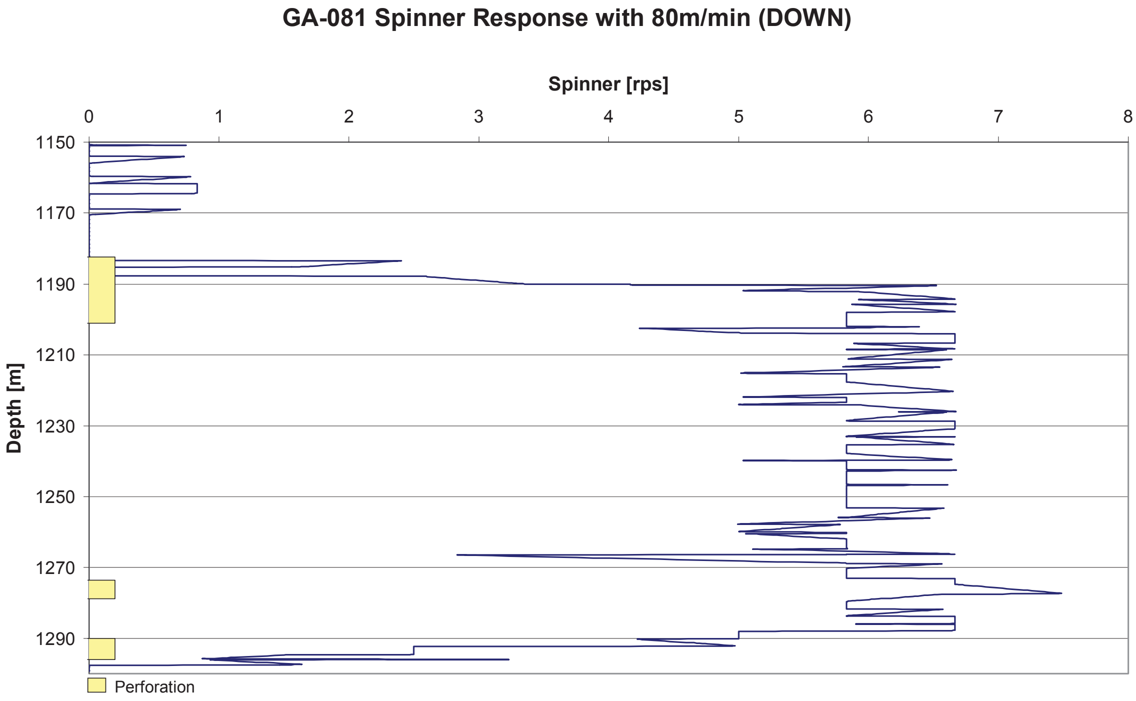

Fig.E.13: GA-081 Spinner Response with 80m/min (DOWN)

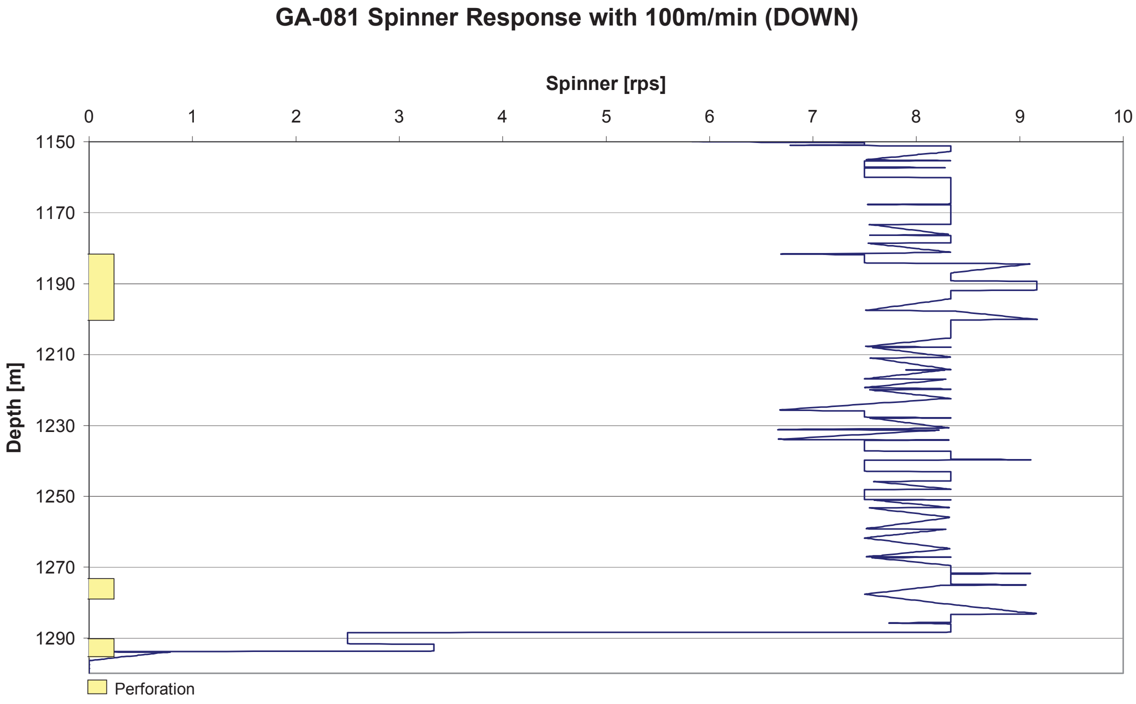

Fig.E.14: GA-081 Spinner Response with 100m/min (DOWN)

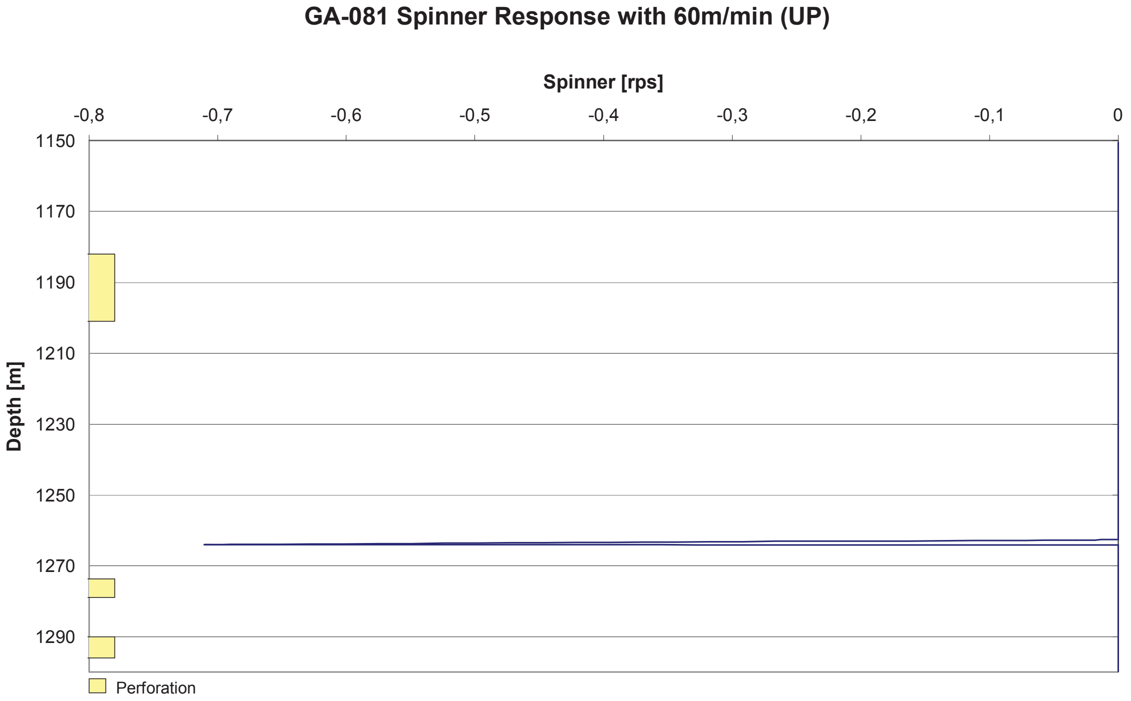

Fig.E.15: GA-081 Spinner Response with 60m/min (UP)

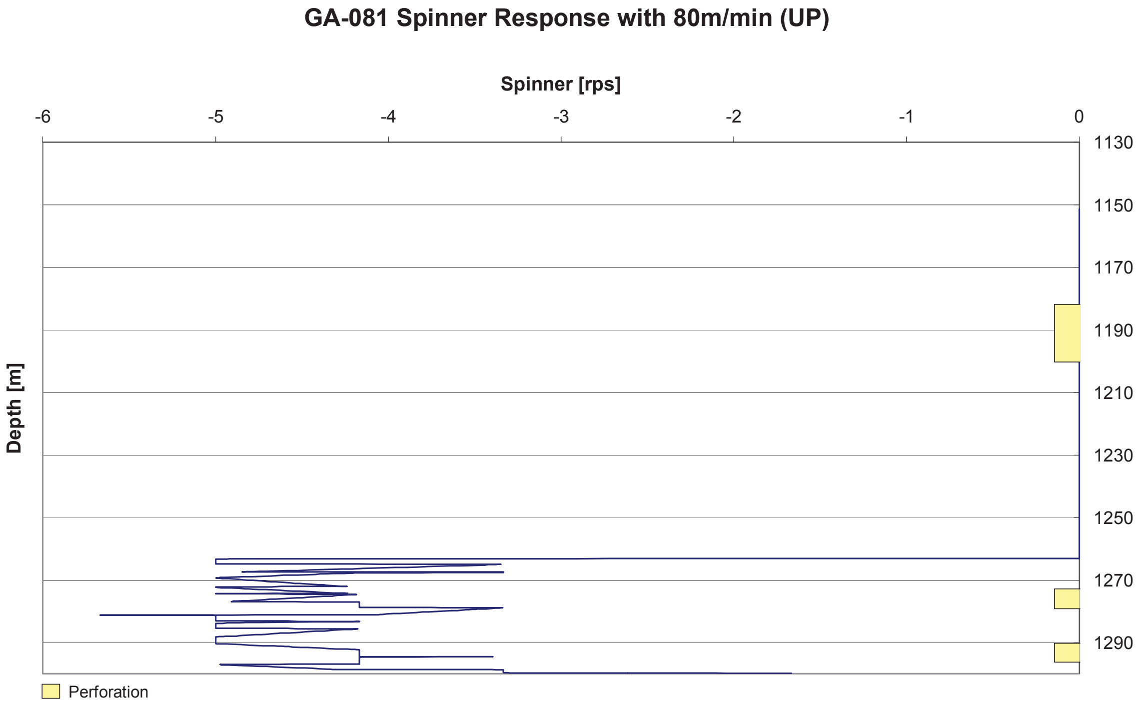

Fig.E.16: GA-081 Spinner Response with 80m/min (UP)

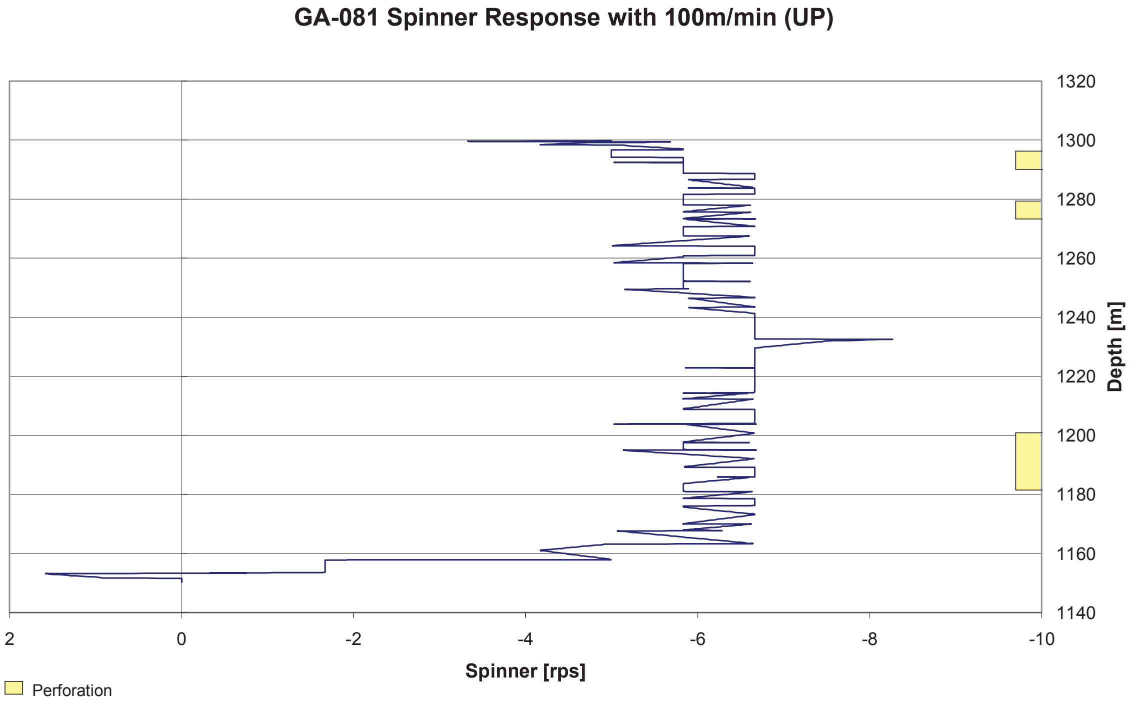

Fig.E.17: GA-081 Spinner Response with 100m/min (UP)

Appendix F: Tracer Costs

F.1 Pilot-Tracer-Test

					Total	Percent of Total Costs
Design						
Tracer Design (including data preparation)					**8.000 €**	**10,4%**
Tracer material						
			[kg]	**[€/kg]**		
Ammoniumthiocyanat			1000	10,95	**10.950 €**	**14,2%**
Tracer Injection						
			[hrs]	**[hrs/h]**		
Workover			16	250	**4.000 €**	**5,2%**
Tracer Analysis						
	analysed samples	**in percent**	**[€/sample]**	**Total**		
	1612	100%	42	€ 67.704		
	1451	90%	42	€ 60.934		
	1290	80%	42	€ 54.163		
	1128	70%	42	€ 47.393		
	967	60%	42	€ 40.622		
	806	50%	42	€ 33.852	**€ 33.852**	**44,0%**
	645	40%	42	€ 27.082		
	484	30%	42	€ 20.311		
Sampling						
	samples taken	**[min/sample]**	**[hrs]**	**[€/hrs]**		
	1612	15	403	50	**20.150 €**	**26,2%**
Total Costs					**76.952 €**	**100,0%**

Tab.F.1: Tracer Costs for the Pilot-Tracer-Test

F.2 FBA-Tracer-Test

					Total	**Percent of Total Costs**
Design						
Tracer Design (including data preparation)					**8.000 €**	**1,5%**
Tracer material						
		[kg]	**[€/kg]**	**Total**		
GA-012		54,3	300	€ 16.290		
GA-20A		43,3	600	€ 25.980		
GA-035		47,7	600	€ 28.620		
GA-040		75,4	300	€ 22.620		
GA-081		84,8	300	€ 25.440	**118.950 €**	**22,1%**
Tracer Injection						
Documetation, Procedure, Data-Sheets				€ 4.750		
Tracerspecialist for Injection (3 days)				€ 5.100		
Injection - equipment for 10 days (incl. mail service)				€ 2.000		
Board&Accomodation' for personel				€ 2.200		
Mobilization charge for equipment				€ 750	**14.800 €**	**2,7%**
Tracer Analysis						
	analysed samples	**in percent**	**[€/sample]**	**Total**		
	1344	100%	700	€ 940.800		
	1210	90%	700	€ 846.720		
	1075	80%	700	€ 752.640		
	941	70%	700	€ 658.560		
	806	60%	700	€ 564.480		
	672	50%	700	€ 470.400		
	538	40%	700	€ 376.320	**€ 376.320**	**69,9%**
	403	30%	700	€ 282.240		
Sampling						
	samples taken	**[min/sample]**	**[hrs]**	**[€/hrs]**		
	1344	15	336	50	**20.150 €**	**3,7%**
Total Costs					**538.220 €**	

Tab.F.2: Tracer Costs for the Pilot-Tracer-Test