Executive Summary

The Bergermeer gas field, in Taqa's onshore Bergen concession, will potentially be converted to an underground gas storage (UGS) facility. The present study is concerned with the construction and history matching of a subsurface model for the Bergermeer field, as well as the fields immediately adjacent (Bergen and Groet) which could conceivably be in communication with it. All three fields are producing from the Rotliegend formation.

There is some heterogeneity visible in the well logs (low porosity/permeability streaks). The available data does not allow clear determination of the nature of these streaks. A variation of notional 3D models was made to cover a range of possibilities.

The material balance of the reservoirs shows that there is little or no communication between the fields, and similarly little or no aquifer. Nevertheless, the observed contact rises in Bergermeer and (to some extent, depending on the interpretation of the most recent observation) Groet can be explained well.

The main uncertainty from the history match concerns the relative sizes of the two compartments of the Bergermeer field, and the nature of the baffle separating them.

The well tests, in combination with the contact rise fix the horizontal and vertical permeability reasonably well: horizontal permeabilities are of the order 500 mD, with k_v/k_h not far from 1 Some uncertainty on the overall permeability level remains, related to the fact that there is certainly a permeability profile over the reservoir zone, of which the well tests only show an average. Nevertheless, high k_v/k_h values would indicate that the heterogeneities seen in the logs have horizontal length scales less than 100m.

The p// behavior leaves little room for a significant aquifer. The model shows how the observed contact rises can be matched nevertheless, by means of a tilted contact. Observations of the GWC in other wells than BGM1, most notably BGM7, could test this prediction.

Taking the reservoir flow simulation models into UGS forecast, there appears little risk of subsurface losses out of the Bergermeer field; the field as a whole is expected to show fairly simple, tank-like, behavior (even if we assume, contrary to well test evidence, the heterogeneities to be continuous and prominent, and k_v/k_h to be low). However, there are some complexities in the interaction between the two Bergermeer compartments. In particular the contact movements in the smaller compartment (around well BGM7) can be quite large. They result in a risk of water production during production cycles. Since a not insignificant part of the volume is in this compartment, there is an associated risk of capacity limitation.

1 Introduction

The Bergermeer gas field is part of the onshore Bergen concession. The field has produced since 1971, from an original gas volume of about 17 Nm^3 in two communicating compartments. It is nearing the end of its field life, and is currently considered for conversion to an underground gas storage (UGS) facility. The main objective of the present study, commissioned by Taqa Energy BV (formerly BP Netherlands), is to build a subsurface model for the field to assess its behavior of the field under UGS conditions.

A particular focus of the study is the potential interaction of the Bergermeer field with its two closest neighbours, Groet and Bergen, also producing from the Rotliegend formation. Figure 1-1 shows the positions of the three fields. The three fields were originally on approximately the same pressure gradient, and thus could be in communication. Under UGS conditions, the Bergermeer field will be repressurized, whereas Bergen and Groet, which are also almost depeleted will (at least initially) be at quite low pressures. Thus, if there is any communication, this could pose the risk of UGS gas leakage.

In addition, if the Bergermeer field is in contact with an aquifer, the behaviour of the UGS will become more complex. Since a 20m rise of the gas-water contact (GWC) has been observed in the Bergermeer field, the presence of an aquifer could prevent this contact from going back down if the field is repressurized. In other words, the GWC rise could cause a UGS capacity reduction. Therfore the explanation of the contact rise, the assessment of aquifer strength, and the prediction of contact behaviour in the future form another objective of the project.

In summary, the initial primary objectives were:

- Reservoir pressure changes with injected/produced volumes (static as well as transient)
- Productivity and injectivity of new and existing wells
- Water influx/efflux into the reservoir(s)
- Behaviour of different compartments

Secondary objectives:

- Gas migration/flow patterns and different quality gas mixing in the reservoir.

This latter objective was not tackled beyond a pilot level (using passive tracers), to ensure that the system set up allows for a straightforward extension of the forecast models once concrete goals are given.

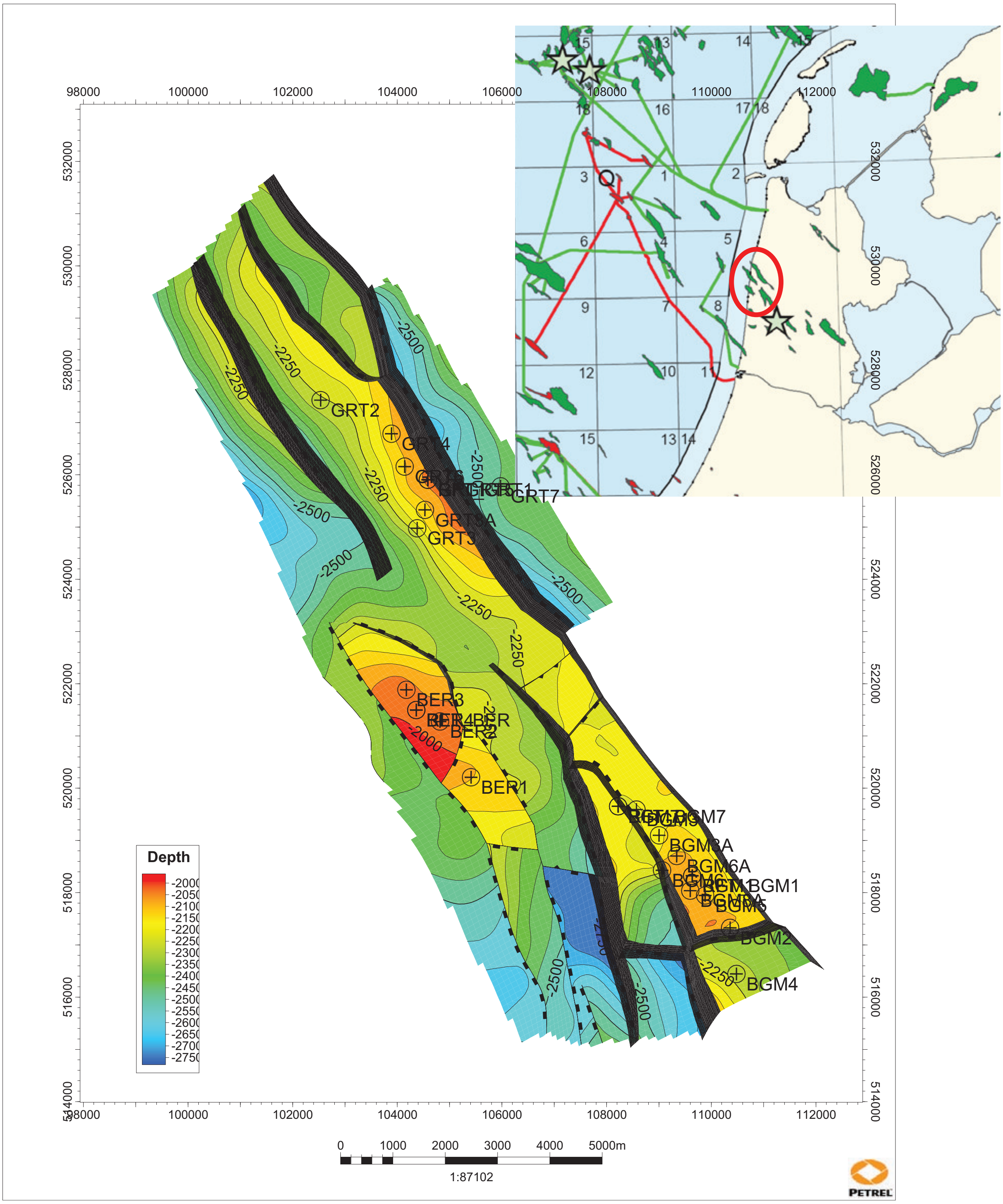


Figure 1-1 **Location of Bergen concession fields that were part of the study: Bergen (BER), Groet (GRT) and Bergermeer (BGM). The latter field is the main focus of this study. The indicated well positions are the top reservoir intersections.**

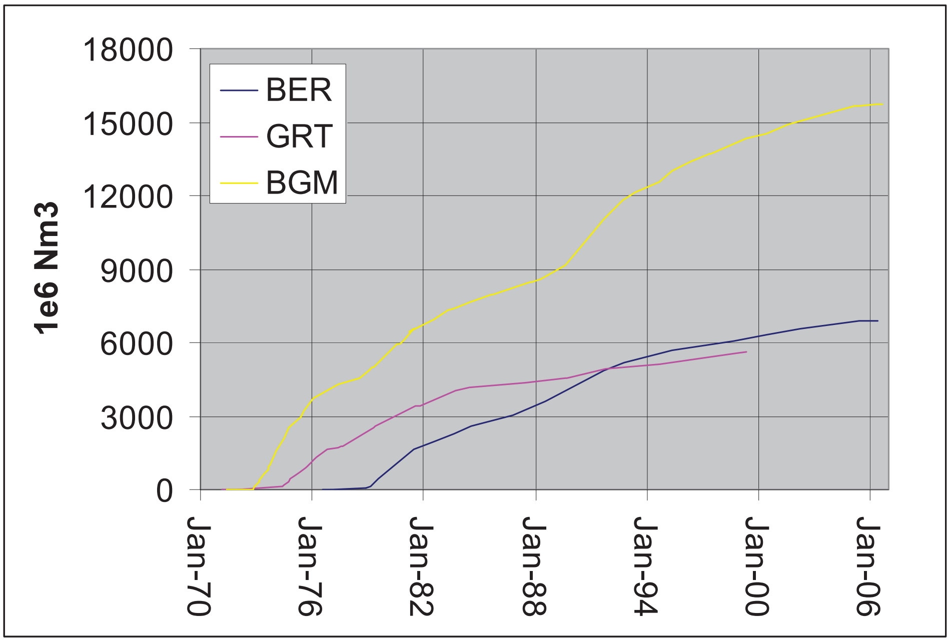


Figure 1-2 Cumulative production of the three fields in the area of interest (AOI).

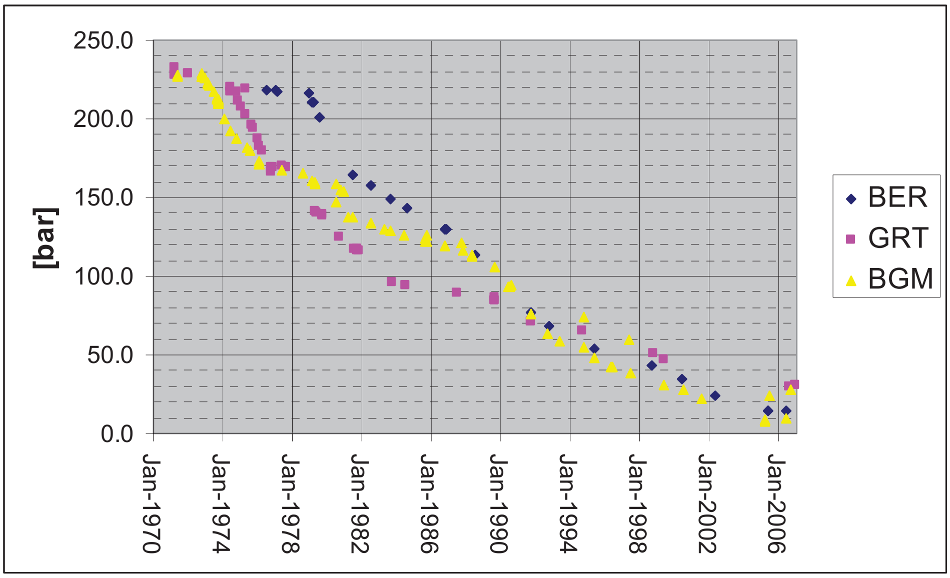


Figure 1-3 Pressure history of the three fields in the area of interest (AOI).

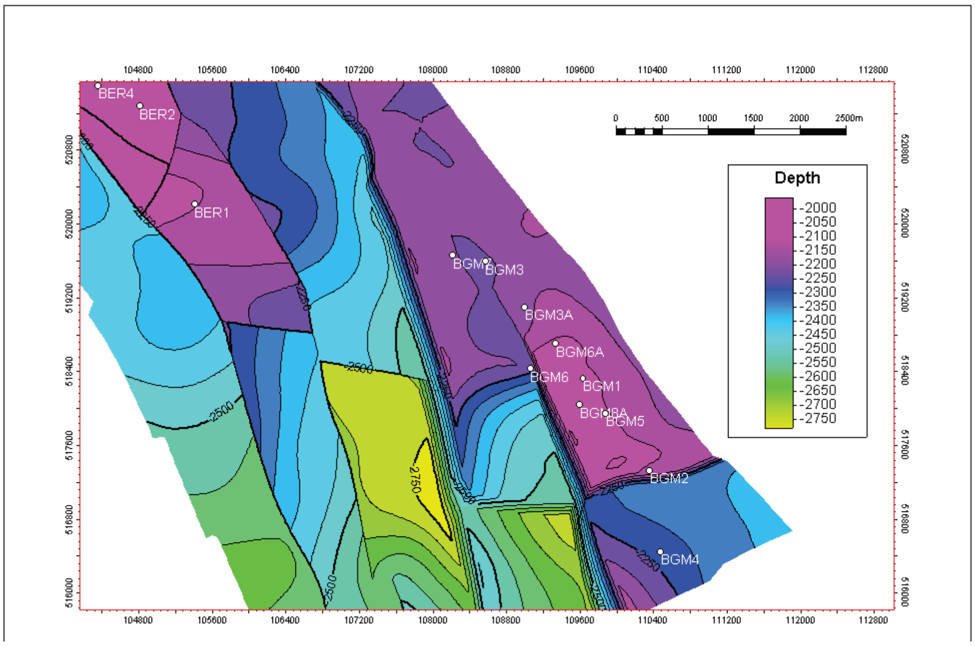


Figure 1-4 Location of BGM wells. Points plotted are top Rotliegend (ROSLU) reservoir picks. Well BGM4 is a water injector, in a fault block S of the main BGM block. Pressures in BGM4 are much higher than in the main BGM block.

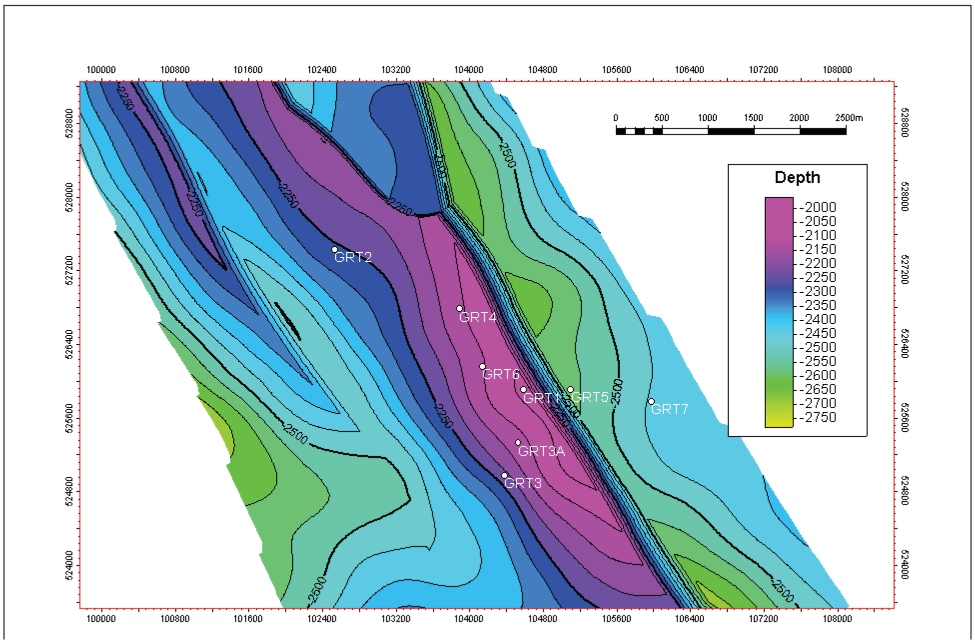


Figure 1-5 Location of GRT wells. Points plotted are top Rotliegend reservoir picks. Wells GRT5 and GRT7 are drilled into a different fault block than the main GRT block, with a different pressure regime.

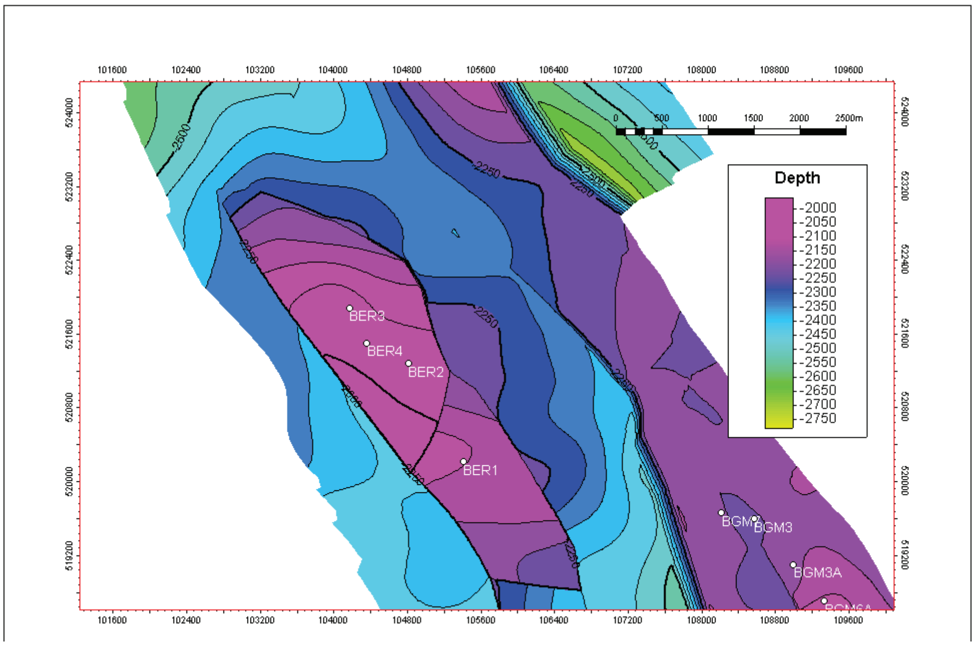


Figure 1-6 Location of BER wells. Points plotted are top Rotliegend reservoir picks.

Part I Static Modeling

2 General Geology

2.1 Geological Background

2.1.1 Regional Sedimentology

During the Permian, the paleogeography of NW Europe was dominated by a series of large basins extending from onshore UK in the west to Lithuania in the east. During the Rotliegend, two sag basins evolved: the Southern and Northern Permian Basin (Figure 2-1). Especially the Southern Permian Basin is well known from hydrocarbon exploration. Deposits of Bergermeer, Groet and Bergen belong to the Anglo-Dutch Basin, which is a sub-basin of the Southern Permian Basin.

The Southern Permian Basin was completely surrounded by land-masses (Figure 2-1), which served as sediment source areas. Due to the pre-dominantly arid climate, a large desert area evolved in the Southern Permian Basin (and elsewhere). In the deepest areas of the basin, terminal playas (Figure 2-2) prevailed, whereas at the basin margins, fluvial systems approached from the surrounding land-masses, carrying sediments into the basin. Between the playas and the alluvial systems, sandflats and dune areas formed a widespread facies belt (Figure 2-2). These dune/sandflat areas created sediments, which provide a high potential for good reservoir properties.

2.1.2 Facies Interpretation for the AOI; Discussion of cores

The reservoir unit of Bergermeer belongs to the Upper Slochteren Formation, which consists of dunes and sandflats facies (Figure 2-3). Paleogeographically, it therefore belonged to the rather proximal basin part. Occasional fluvial influences support this (cf. [10]).

Looking at the well logs of the fields over the reservoir section (chapter 3), we see that typically the gamma ray shows a flat, characterless curve, whereas the sonic and density logs feature a bell-shaped curve, indicative for lower reservoir properties in the upper and lower section of the Rotliegend. The middle section, which is also the thickest part of the Rotliegend, reaches quite high porosity values (up to 34%). Some low-porosity streaks occur throughout all wells within the whole middle interval. It was attempted to investigate the origin of the low-porosity streaks and to correlate them within Bergermeer. Moreover, it at first appeared useful to subdivide the Rotliegend deposits into three units, the top unit referred to as known as 'Weissliegend'.

However, (core) information available from earlier reports ([1], [10]) did not cover sufficiently the (best) middle interval to extract the necessary information. Therefore, one day was spent for a core visit at TNO.

The cores of the full Rotliegend interval of BGM 1 as well as GRT 3, but only the uppermost meters of BGM2 were reviewed (under tight time constraint)s for their sedimentary depositional system and the character of the low-porosity streaks. Also, it was intended to verify the subdivision and correlation of the Rotliegend into three sub-units.

The subdivision into three units within the Rotliegend could not be verified. The cores of BGM1 and GRT3 revealed clearly, that the base Weissliegend, as was available in the provided log and well top data set, is not reflected in the sediments of the cored section. The cores do not show any facies change within the envisioned interval. The same applies to the porosity change from the middle to the lower interval of the Rotliegend. Therefore, for later modelling, it was decided not to subdivide the Rotliegend at all.

The cores of BGM 1 and BGM2 show predominantly deposition on sandflats, whereas the core of GRT 3 is dominated by dune deposits. Figure 2-4 and Figure 2-5 visualize the depositional interplay of depositional environments. The outcrop photo of Figure 2-7 shows a cross-sectional view of laterally and vertically alternating dune and interdune areas.

In the cores, the sandflats are characterized by horizontal lamination, low-angle bedding and typical bimodal sorting. Coarser quartz laminae were generated, when the coarse grains were blown onto the flat interdune area and stuck onto the slightly wet surface (wet sandflat environment). The core of BGM 1 also shows two thin intervals of (arguable) fluvial influence, represented by some clay flakes and water ripples (Figure 2-8, Figure 2-9). This is a very subordinate amount of sediment (thickness in the range of 15cm maximum) and certainly not to expected to be extensive or of major influence to reservoir performance.

The Groet (GRT3) core is interpreted pre-dominantly as dune facies, but also shows intervals of sandflats. Figure 2-6 displays a nice vertical contact of dune facies (in the lower part) with sandflat (in the upper part). The cores of the dune environment show well sorted grain sizes, non-horizontal lamination, cross-bedding, and high angle bedding (up to 25°).

The nature of the low-porosity streaks could not be identified macroscopically. There was no visible facies change. Within the cores anhydrite-healed fractures were cited, also within intervals of low porosity. The low-porosity intervals also show high density, so a high amount of these fractures in an interval may be able to cause a low-porosity streak. However, these fractures could not be confirmed to be present in all low-porosity locations. The pores may also have been filled by early, strata-bound cementation and therefore reducing porosity. The sorting of the grains also may play a role.

It is important to realize that the core was not perfectly preserved, particularly in the best, central, part in BGM1. This reduces the number of available sample locations (as well as adversely affecting the depth identification of the parts that remain). Therefore, only educated guesses can be made regarding the genetical background. In order to clarify this question, further petrophysical core analysis would be needed.

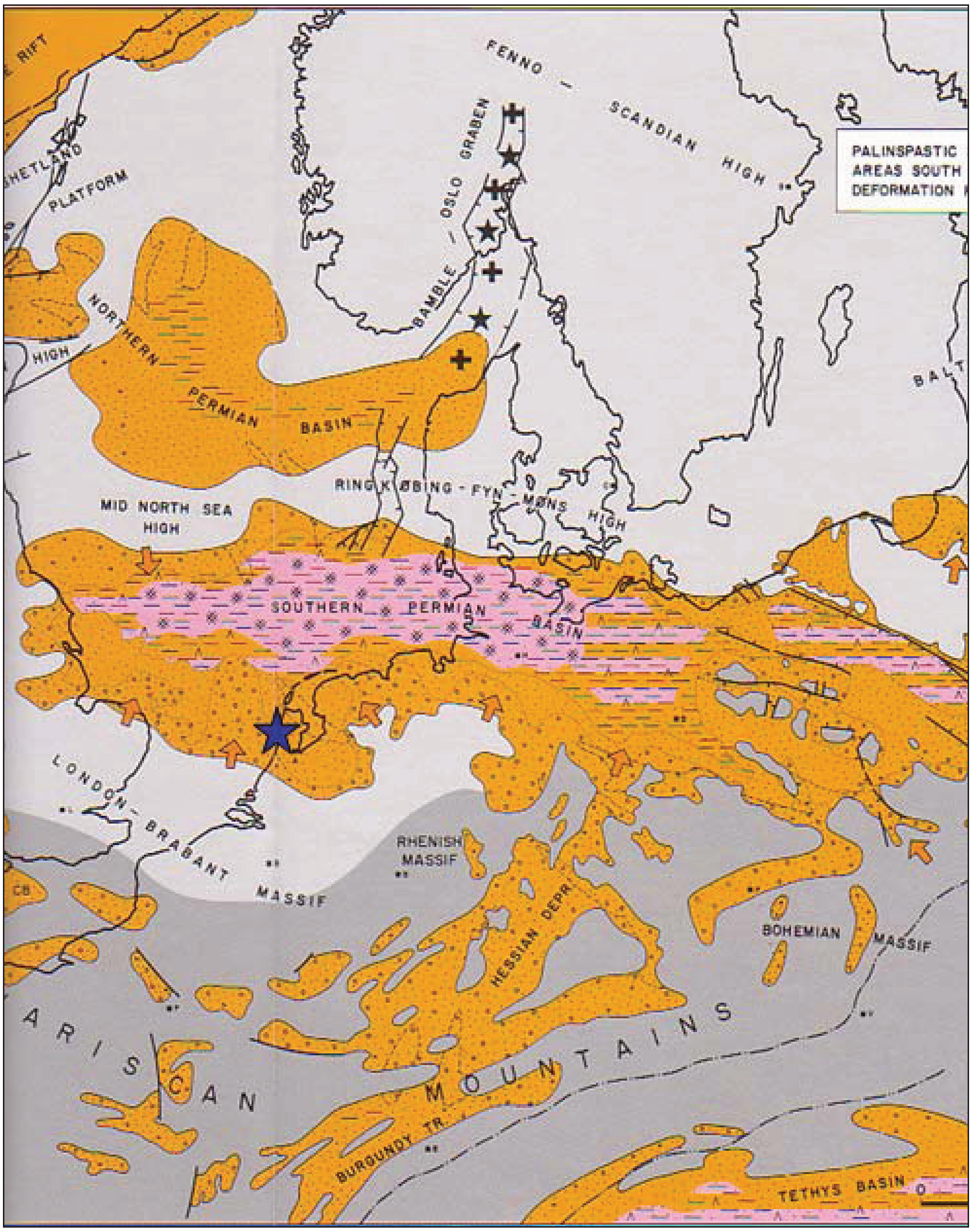


Figure 2-1 **Palinspastic map of the Permian Basins with the recent-continent contours Bergermeer (see blue star for position) was situated in a proximal position (with regards to the land-mass) and therefore consists predominantly of sandflats and dunes, which is a very favorable depositional setting with regards to the quality of the reservoir properties.**

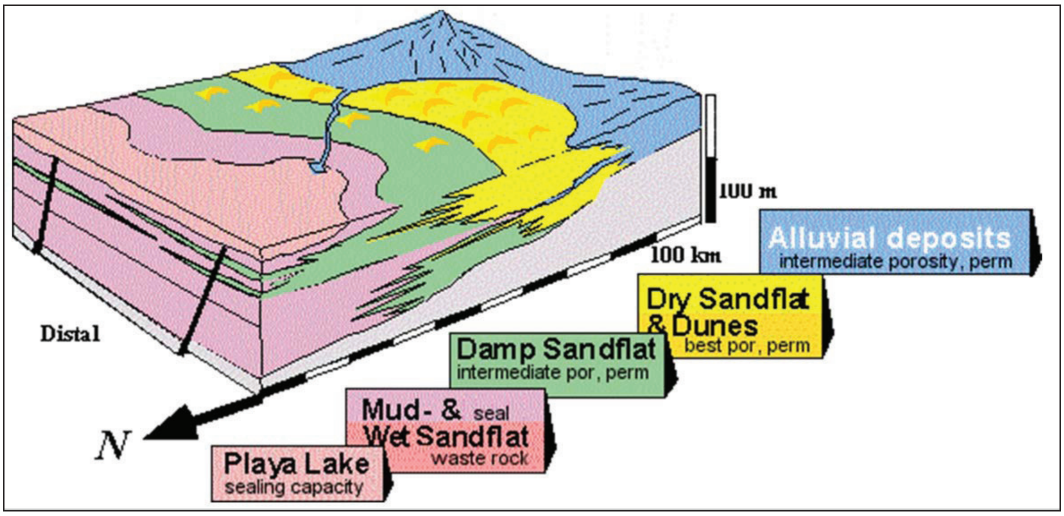


Figure 2-2 Sketch of the depositional setting within the Permian Basin. The depositional system of Bergermeer would be located within the 'dry sandflat and dunes' area.

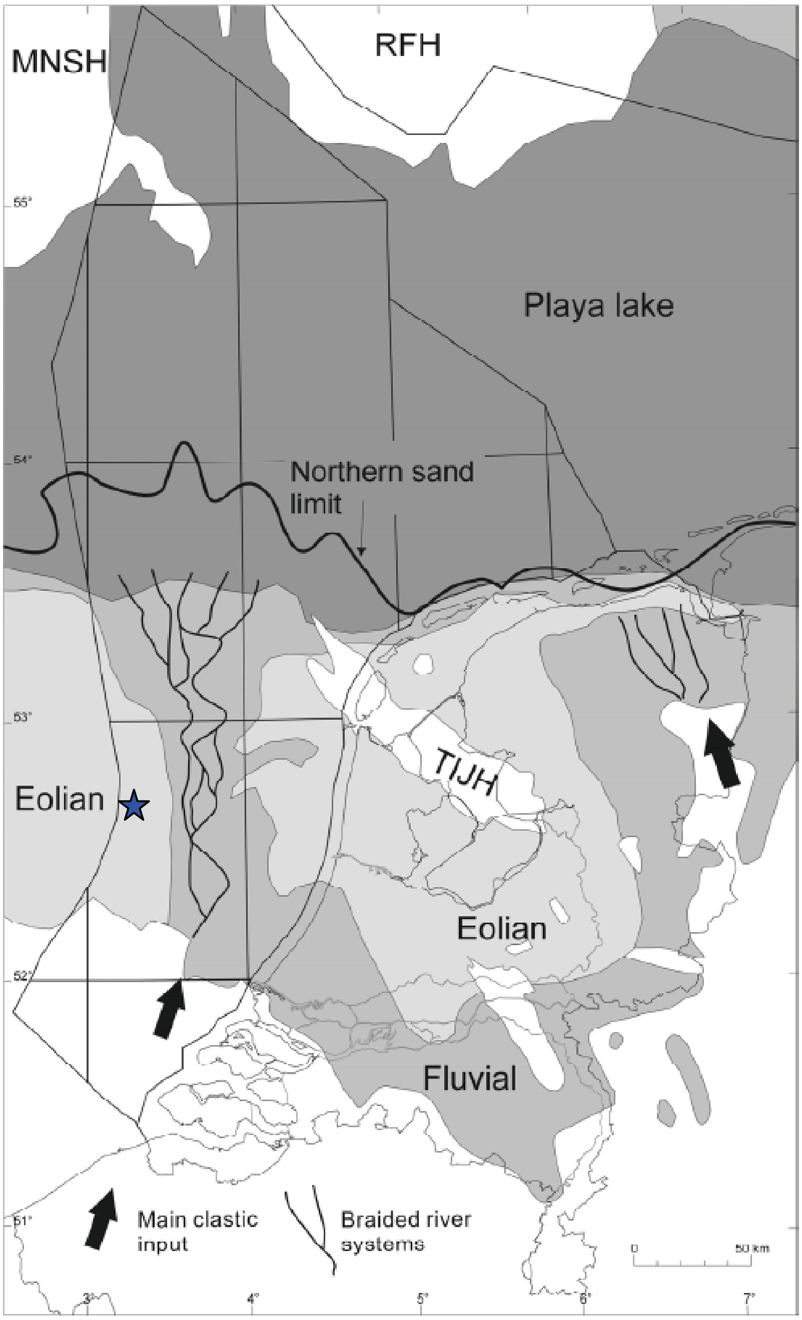


Figure 2-3 **Facies distribution at the onset of the Lower Slochteren Formation, which comprises the reservoir unit of Bergermeer, Groet and Bergen. The blue star marks the position of Bergermeer.**

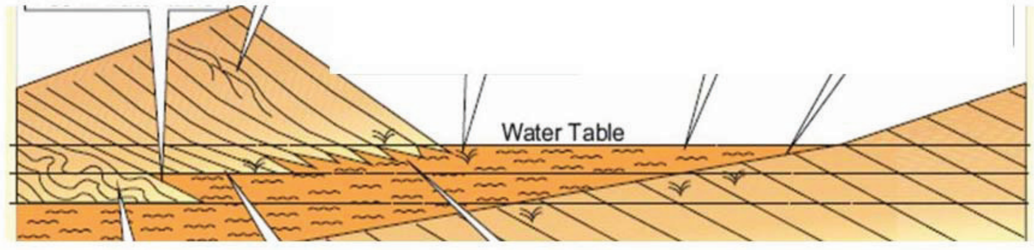


Figure 2-4 Sketch visualizing the sand dune and interdune (=sandflat) depositional environment. The dark orange area corresponds to the sandflat area, the lighter orange to the dunes.

Figure 2-5 Recent analogue example for a desert environment with dunes and interdune areas Note, that the envisaged environment for Bergermeer is supposedly more arid than the shown desert.

Figure 2-6 GRT3 core – contact cross-bedding with horizontally layered section. [Scale is in cm.]

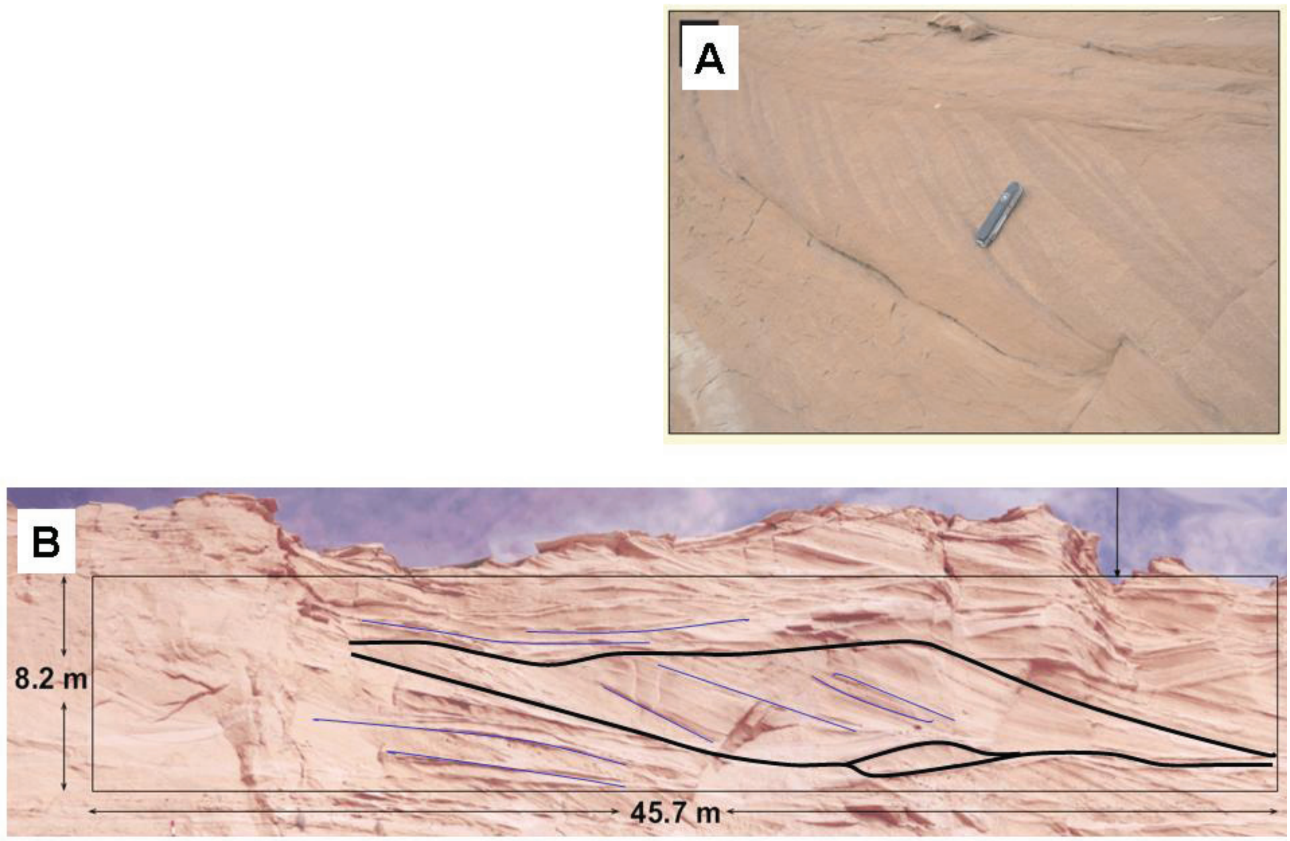


Figure 2-7 Pleistocene eolian deposits from Oman. A: small-scale example of vertical changes from strongly dipping, dune strata and horizontally laminated interdune areas. B: large-scale outcrop example for lateral and vertical juxtaposition of dune and interdune strata.

Figure 2-8 **Fluvial water ripples in GRT3. The core sample is from 2462m MD, the overall thickness of this fluvial interval is about 15cm.**

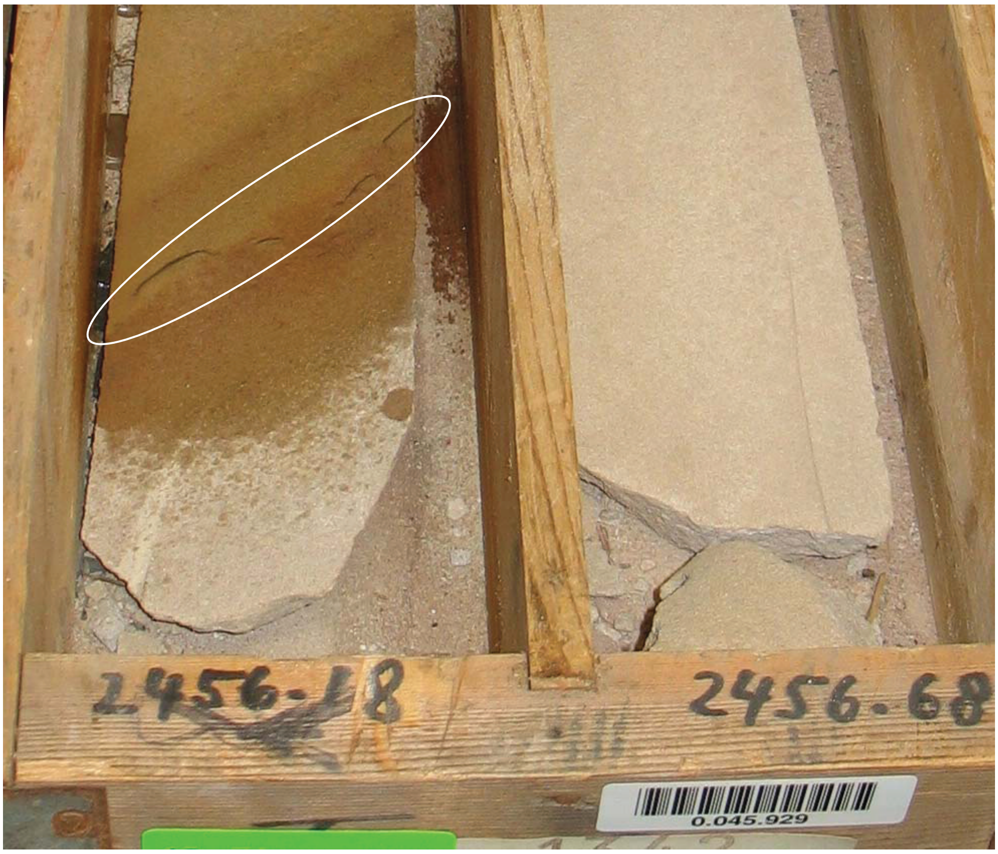


Figure 2-9 Mud flakes suggest fluvial influence in the upper part of the GRT3 cores.

2.1.3 Regional Structural Geology

The studied fields are located in the western part of the Central Netherlands Basin (CNB). The CNB is a NW-SE-oriented complex graben structure bounded to the northeast by the Texel-IJsselmeer High and to the southwest by the Zandvoort Ridge (Figure 2-10, Figure 2-11).

The Southern Permian Basin was progressively fragmented. During the Middle and Late Permian, several minor rift pulses occurred. However, during the Zechstein, considerable differential fault movement is recorded from the area covered by the anhydrite platforms at the margins of the Zechstein basin. Several fault-bounded basins and half-grabens resulted.

From Triassic to Cretaceous, extensional tectonics related to the break-up of Pangaea caused highly differentiated subsidence.

These extensional phases subdivided the Southern Permian Basin into a number of smaller (half-) grabens. The dominant structural trend follows the trend of the depositional basins (NW-SE, see Figure 2-10), but a N-S directed trend also exists.

Later compressional tectonics, from Cretaceous on, complicated the overall structural picture by reactivating and inverting earlier faults.

2.1.4 Structural style in the area of interest

The Bergermeer, Bergen and Groet fields are located in a classical horst-and-graben-structure. Figure 2-12 and Figure 2-13 give an overview of the structure as was interpreted from seismic by Taqa. The modelled area is bound to the west and east by two main faults with an offset of several hundred meters. The area of interest (AOI) can be divided into three main structural domains (Figure 2-13, Figure 2-14):

1. A northern area with NE-dipping, tilted half-grabens. Groet is located on one of the tilted half-grabens.
2. A less obviously deformed area acting as transfer zone between the northern and southern modelled area. Bergen is located on an elevated horst block in the west.
3. The southern part of the modelled area is the most complex deformed area. It consists of two horst structures separated by conjugate faults creating a central graben. On the eastern shoulder of the graben, Bergermeer is located on NE-tilted half-grabens.

The spillpoint between Bergermeer and Groet is located in the transfer zone. The internal deformation of the transfer zone is below seismic resolution and therefore rather uncertain. Transfer zones are in general prone to folding, faulting and fracturing in order to accommodate the different amounts of extension in the adjacent domains, as well as the predominant direction of fault dip (in this case between Groet and Bergermeer area). Therefore, it is very likely, that a substantially higher degree of deformation occurred in the area between Bergermeer and Groet than inferred from seismic.

One means to investigate sub-seismic scale deformation is given by the cores. During the core visit, small-scale extensional faulting was observed on the cores (Figure 2-15). Also, decimetre-long anhydrite-healed fractures are present in the cores of BGM 1 and GRT 3. The cores were not taken oriented; therefore the azimuth of the fractures cannot be determined. However, since the wells are sub-vertical within the cored reservoir sections, any information about fracturing can only be very limited.

2.2 Well Top Picks

Well top picks were provided by Taqa (Table 2-1).

Top reservoir is quite unambiguous from the well logs, and these picks were adopted as is.

Base reservoir picks (DCCR) are more rare: only BGM1, BGM 8A and BER1 go this deep. Of these three, BER1 was not used, because the base reservoir pick (UCRO) was assigned with a different code, and this was discovered only after the model had been created.

The Taqa picks included several intermediate ones, most notably ‘Weissliegend’, referring to the poorer upper reservoir section. However since the BGM1, BGM2 and GRT3 cores showed no abrupt changes at candidate depths (section 2.1), and since the logs show only gradual changes as well (see graphs in chapter 3), which would make these picks quite arbitrary, it was decided to drop any intermediate picks.

Table 2-1 **Well tops availability in Bergermeer, Groet and Bergen Fields**

The nomenclature (based on [11]):

Top ROSLU = Upper Slochteren Sandstone Member, Upper Rotliegend super group

Top DCCR = Ruurlo Formation, Limburg super group (Carboniferous)

TD = total depth of penetration

Depth (MD)	Well Top	Well
2508	Top ROSLU	GRT1
2599	Btm WEISSLIEGEND	GRT1
2849	TD	GRT1
3756	Top ROSLU	GRT2
3844.8	TD	GRT2
2454	Top ROSLU	GRT3
2497.13	Btm WEISSLIEGEND	GRT3
2707	TD	GRT3
855	Top KNGL	GRT3A
2254	Top ROSLU	GRT3A
2295.01	Btm WEISSLIEGEND	GRT3A
2409.4	TD	GRT3A
2600	Top ROSLU	GRT4
2655.76	Btm WEISSLIEGEND	GRT4
2855	TD	GRT4
2623	Top ROSLU	GRT5
2648.25	Btm WEISSLIEGEND	GRT5
2727	TD	GRT5
2310	Top ROSLU	GRT6
2377.12	Btm WEISSLIEGEND	GRT6
2475	TD	GRT6
2826	Top ROSLU	GRT7
2858.84	Btm WEISSLIEGEND	GRT7
2935	TD	GRT7
2511	Top ROSLU	BER1
2548.5	Btm WEISSLIEGEND	BER1
2842.44	Top UCRO	BER1
2856.4	TD	BER1
2555	Top ROSLU	BER2
2595.72	Btm WEISSLIEGEND	BER2
2632.5	TD	BER2
2835	Top ROSLU	BER3
2890.51	Btm WEISSLIEGEND	BER3
3029	TD	BER3
2573.25	Top ROSLU	BER4

Depth (MD)	Well Top	Well
2621.68	Btm WEISSLIEGEND	BER4
2751.72	TD	BER4
2079.5	Top ROSLU	BGM1
2137.66	Btm WEISSLIEGEND	BGM1
2296.2	Top DCCR	BGM1
2314	TD	BGM1
2481.5	Top ROSLU	BGM2
2529.86	Btm WEISSLIEGEND	BGM2
2660.86	TD	BGM2
2905.5	Top ROSLU	BGM3
2914.5	Btm WEISSLIEGEND	BGM3
2960	TD	BGM3
2569	Top ROSLU	BGM3A
2623	Btm WEISSLIEGEND	BGM3A
2664	TD	BGM3A
3287	Top ROSLU	BGM4
3332.26	Btm WEISSLIEGEND	BGM4
3336	TD	BGM4
2228	Top ROSLU	BGM5
2291.39	Btm WEISSLIEGEND	BGM5
2420.09	TD	BGM5
2344	Top ROSLU	BGM6
2392.4	Btm WEISSLIEGEND	BGM6
2395.91	TD	BGM6
2205.5	Top ROSLU	BGM6A
2222.12	Btm WEISSLIEGEND	BGM6A
2363	TD	BGM6A
3171.25	Top ROSLU	BGM7
3218	Btm WEISSLIEGEND	BGM7
3255	TD	BGM7
2125	Top ROSLU	BGM8A
2156.5	Btm WEISSLIEGEND	BGM8A
2319	Top DCCR	BGM8A
2345	TD	BGM8A
2301.1	TD	BGM9

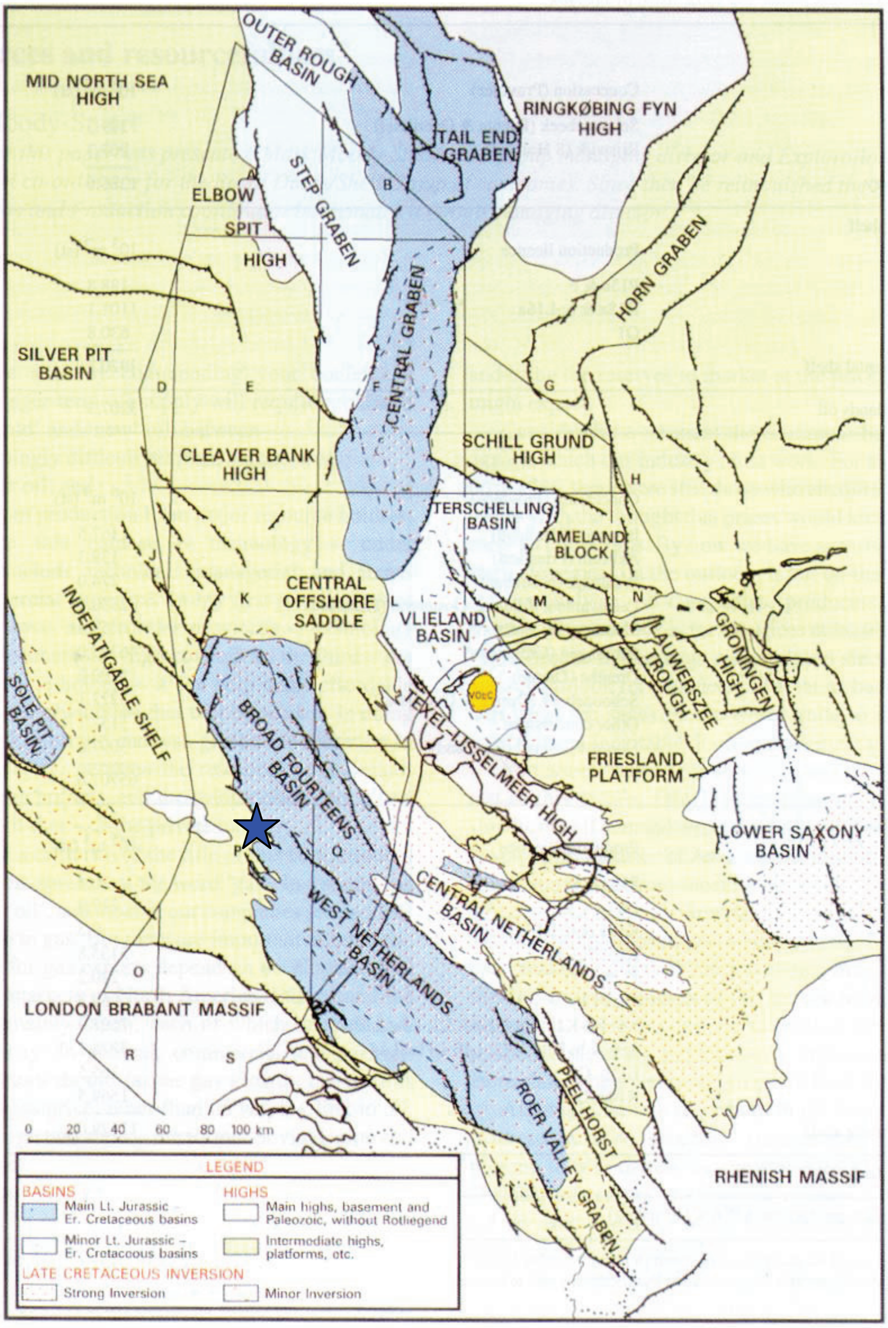


Figure 2-10 **Mesozoic structural geology map of the Netherlands and SW North Sea. The colors outline the extension of the major sedimentary basins. The blue star marks the position of Bergermeer.**

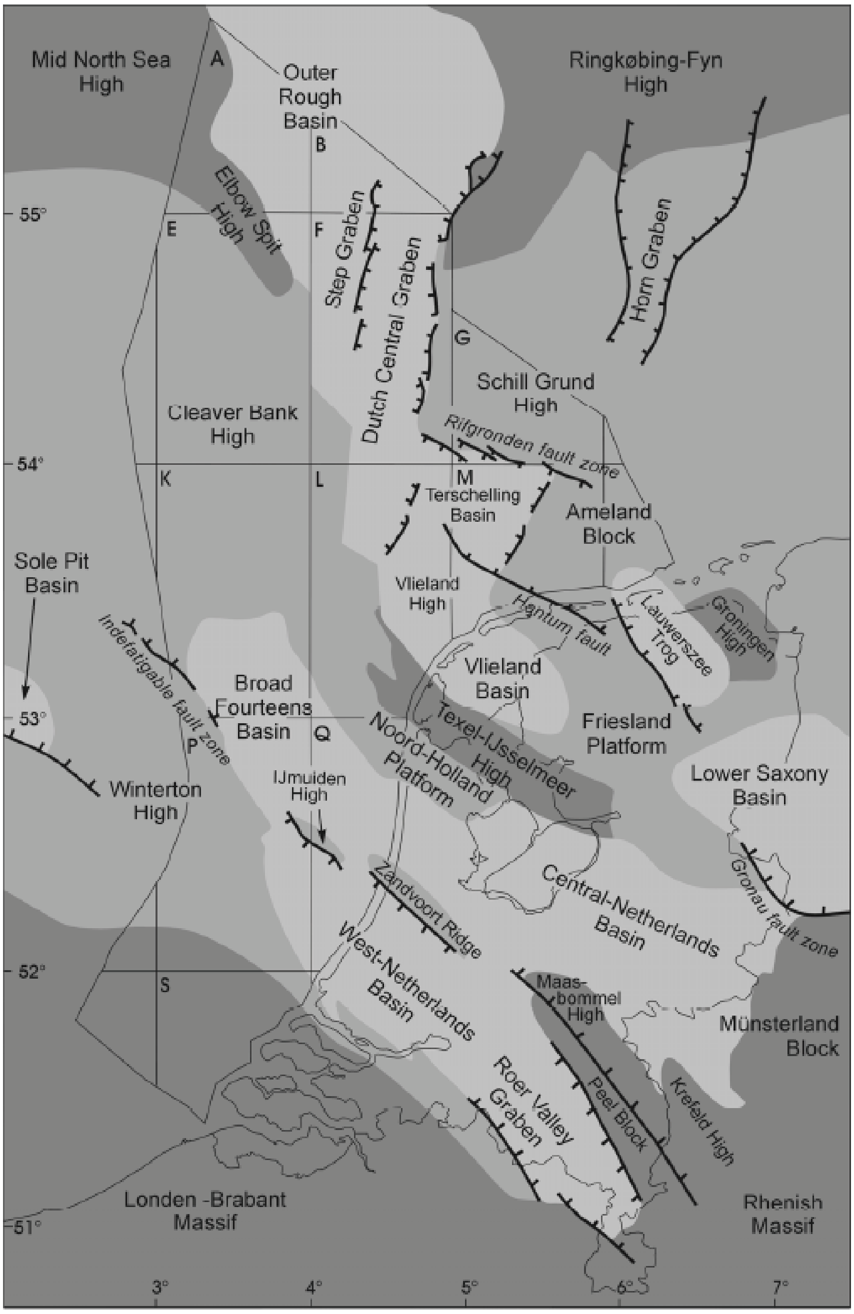


Figure 2-11 **Overview of structures in the Netherlands during the Late Jurassic to Early Cretaceous.**
Note that the ridges/platforms not necessarily existed during deposition of the reservoir unit.

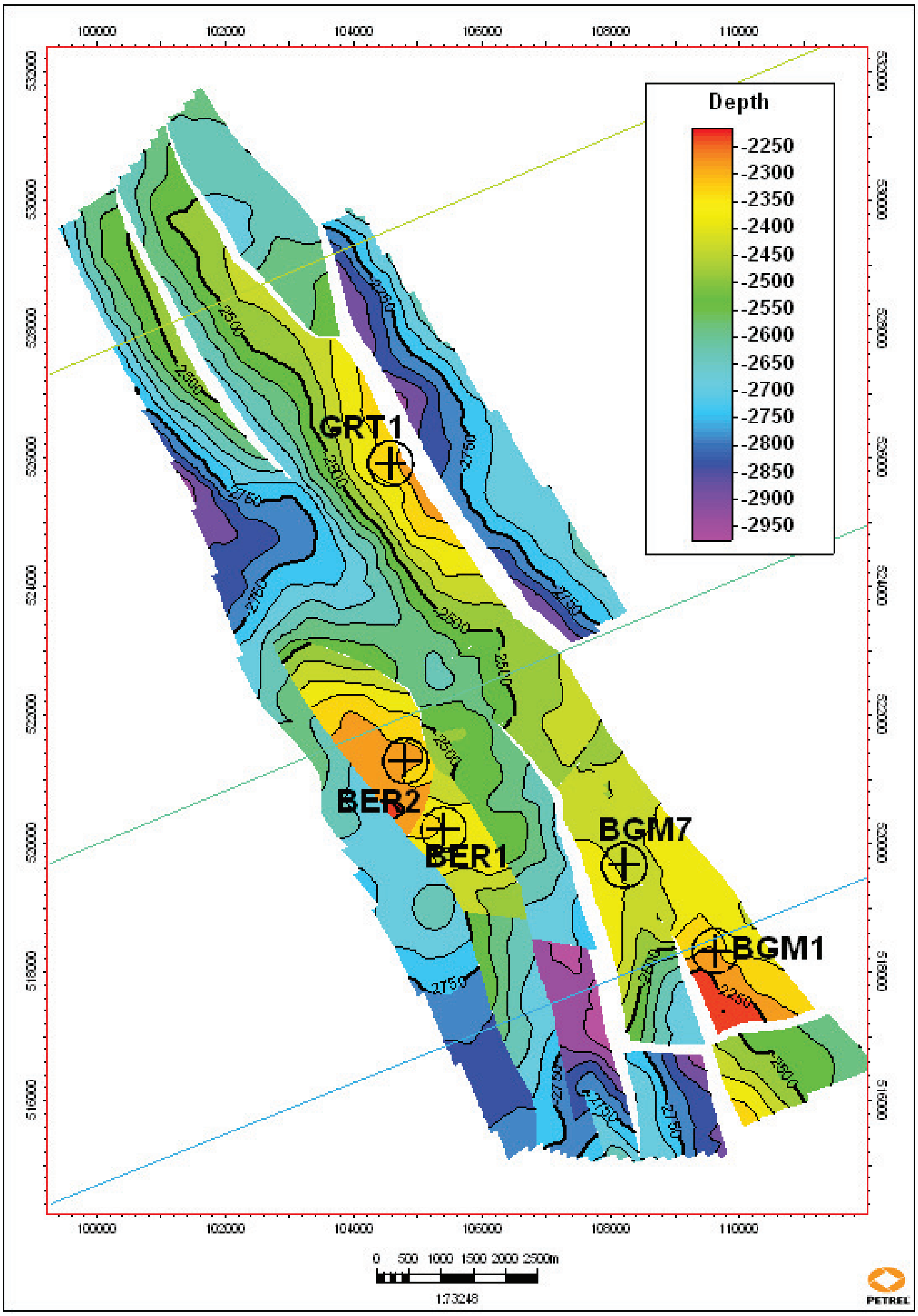


Figure 2-12 Map view of the base reservoir horizon (=Top Carboniferous). The three greenish lines correspond to the position of the intersections shown in Figure 2-13 below. White gaps in the horizons represent faults. For direction of fault offset, please refer to the figure below. Note, that the middle part of the model is hardly faulted, whereas the southern and northern area are offset by horst-and-graben-structures.

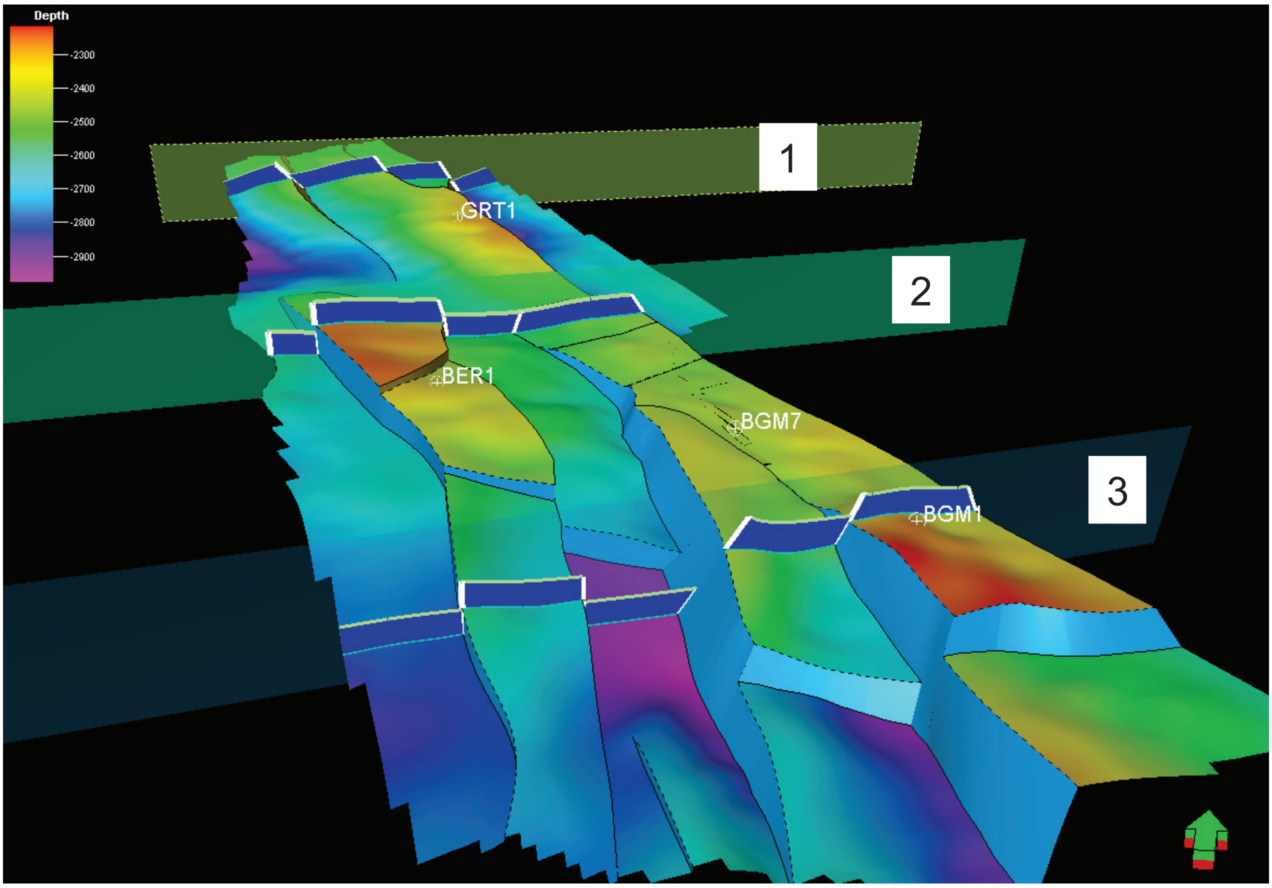


Figure 2-13 View from the south onto the base reservoir horizon (=top Carboniferous). Faults are filled with light blue color. The three intersections (1 – 3) dissecting the model show the reservoir unit in dark blue and faults in white. BGM1, BGM7, BER1, and GRT1 are displayed to indicate the location of the referring fields Bergermeer, Bergen, and Groet. See also Figure 2-14.
Intersection 1: Northern domain: NE-dipping half-grabens.
Intersection 2: Transfer zone: less deformation in the eastern part of the Intersection, which is located in direct extension of the Groet and Bergermeer Fields.
Intersection 3: Southern domain: direction of displacement is opposed to the one in the northern domain.

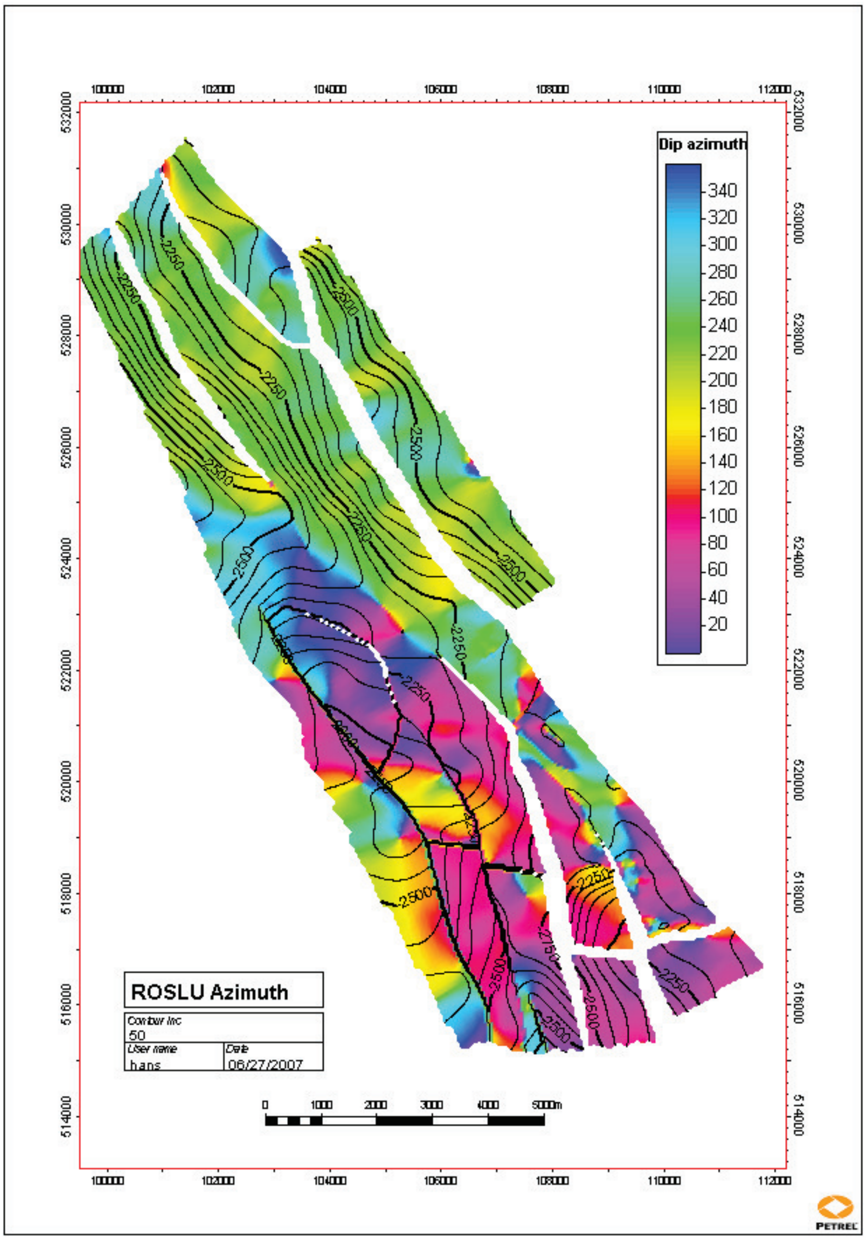


Figure 2-14 **Azimuth map of the to Rotliegend. The change from E-dip to W-dip as we move from BGM to GRT is apparent.**

Figure 2-15 **Anhydrite-healed small-scale faults in core 11 of BGM1.**

3 Petrophysics

3.1 Input Data Overview

A list of logs received can be found in Table 3-1.

Conventional core analysis data (porosity, Kair, Kl) was only available for well BGM1 (Table 3-1). It is not known whether the data is overburden corrected (overburden correction will lower porosities and permeabilities). The data is cross-plotted in Figure 3-1, showing good por/perm correlation.

It should be noted that the petrophysics study [1] reports the availability of more core data; the corresponding GEOLOG project was not available for this study, however.

3.2 Porosity log quality issues

For the present model, the porosity logs are the most critical ones. On the one hand they are used to populate a porosity cube. On the other, permeability is computed from porosity, so that also the permeability cube derives from the porosity logs. As there is a negligible transition zone in BGM, and none was implemented in the model (chapter 5), the Sw logs are not directly used in the simulation model (an average Sw is used in to the relperm model(s)). The conclusion of the petrophysics report [1] that there is, in essence, no shale over the Rotliegend interval is adopted for this study. Hence the Vsh is of secondary importance.

Therefore it is important to QC the porosity logs in particular, as variations in log processing will lead to porosity and permeability bulls eyes that are not a reflection of the subsurface.

From the petrophysics report [1] the principal log for the determination of porosity is the density log. The matrix density used for sandstone is 2.65 g/cc; fluid densities in the Rotliegend are reported as ‘typically’ 0.7 g/cc in the more porous formations in the gas column and 1.1 g/cc in the water leg. The report states that in the tighter upper Rotliegendes, mud densities seemed more appropriate. Density/neutron derived porosities are stated as being used in some places, but it is not stated where. The reasoning is shown by the following comment from the report [1]:

> *In BGM1, the density log appears to be valid across most of the formations except across the Rotliegende. The densities are excessively low and even with very low fluid densities the derived porosities far exceed the core porosity data available. There is no core density data to allow the determination of the appropriate matrix density to use although the composite log does suggest anhydrite cement. The sonic log has been used to derive the porosity in this well.*
>
> *Similar occurs in BGM5, where the density log would appear to be reading very low densities – the sonic is used in the well to derive porosity.*
>
> *IN BGM6 and BGM6A, there is no indication that a density log was run and there is no DRHO curve available. A crossplot of the density and the sonic indicate that the density has probably been derived from the sonic. The sonic has been used to derive porosity in this well.*

For the calibration of these transforms, and in the light of the project's focus on Bergermeer, the BGM1 well is the most important well. Not only is it one of only two that penetrate the whole Rotliegend (but see section 2.2), it is also the one that has the core information. The match between core and log porosity is shown in Figure 3-2, showing that log porosities systematically overpredict core porosities. Comparing BGM2 with BGM1 (Figure 3-3), the following conclusions can be drawn:

- Fluid density in the water leg for the wells where density was used is 1.05 (BGM2)
- Even though the densities in BGM1 were judged too low, the sonic-based porosities are *higher* than the density-based porosities would have been
- Average porosities in BGM1 are 5 pu's higher than in BGM2 (even though the latter does not completely cover the tighter lower Rotliegend).

This difference seems excessive; 5 pu's imply a permeability difference of a factor 3 (Figure 3-1). Logs like the BGM1 PHIE log cannot be used together with logs like the BGM2 PHIE log without causing severe bulls eyes.

Examining the GRT wells, e.g. GRT1 (Figure 3-5), we notice that no fluid correction has in fact been applied. Again the end result is high porosities.

3.3 Porosity log quick-look re-evaluation

Are the density readings in BGM really excessively low? Without carrying out a full petrophysical re-evaluation, two effects should be noted. Firstly, in high-perm sands the mud cake tends to form faster (because water separates off faster into the formation), with the result that high-por sands tend to have less invasion than low-por sands ([3], p. 2-4). Secondly, the density log responds differently to gas: $\rho_{b,log}$ = 1.33 ρ_g – 0.188 ([4]; density in g/cc). For the Bergermeer situation, ρ_g is of the order 0.15 g/cc, so that $\rho_{b,log}$ is about 0.01. I.e. the density log in gas zones reads lower than you would expect on the basis of the gas density.

A useful cross-plot is of the RHOB log values against the core porosities (Figure 3-4). Examining that , we see that RHOB/POR_CORE aligns around a fluid density trend of 0.4 for high porosity, and around 0.7 for low porosity. These values do not in fact appear that excessive. This suggests that if we implement a fluid density that depends on porosity (Figure 3-6), we should be able to achieve a reasonable match. It should be noted that the transform then becomes iterative: RHOB->PHIE depends on the fluid density, which in turn depends on PHIE.

Since there appear to be no major wash-outs across the Rotliegend, hole quality issues were neglected. In the absence of NPHI logs in BGM (except the last two wells) matrix density issues are not easy to quantify. Hence we kept the base assumption of 2.65 g/cc.

The correction for the low amounts of shale was done as for the RHOB→PHIE transform in the petrophysics report, by multiplying with (1-Vsh).

Summarizing, we get:

$$PHIE = (1-Vsh)*(\rho_{ma}-RHOB)/(\rho_{ma}-\rho_f)$$

$$\rho_f = Sw*\rho_w + (1-Sw)*max(0.4,1.05-2.35*PHIE)$$

This gives a ρ_f going down to 0.4 at about 0.28 porosity at Sw=0. Note that the density log sees total porosity; however the Sw in the 2nd equation has not been corrected to a total-porosity Sw for the shale water (this assumes small Vsh). Neither has the Sw been corrected for the modified PHIE (since the Sw is not directly used in the study).

The resulting transforms are graphed in Figure 3-7. Table 4-1lists the wells for which the adapted transform was eventually used, and the wells for which this was not possible (lacking suitable logs).

3.4 Other Petrophysical Results

3.4.1 Salinity

The Rotliegendes resistivities map to an Rw of 0.01 ohmm at a temperature of 200 degF [1]. This implies an NaCl concentration of over 3e5 ppm [5], in essence salt-saturated water. Under these conditions, at reservoir pressure, this maps to a water density of 1.23 g/cc [5].

No formation water sample analysis was provided.

3.4.2 Por/Perm relation

As seen in Figure 3-11, plugs from the low perm streaks do not show a por/perm correlation different from the overall set. Therefore we chose to apply a single por/perm correlation, derived from the BGM1 plugs:

$$Ln[Perm/mD] = -72.956\ PHIE^2 + 63.873PHIE - 4.5065$$

A quadratic relation was used since a linear one seems to overpredict permeabilities both on the high and the low end. The relation is plotted as a yellow line in Figure 3-11. The permeabilities are chopped at 0.1 mD and at 8000 mD, roughly corresponding to the highest and lowest plug values.

Comparing the core por plot with the log por plot, the scatter in the 'poor' streaks is bigger than that in the main facies. A probable reason for this is that, in view of them being relatively thin, the lack of exact core/log alignment affects them more than the 'good' background, whose properties vary smoothly (see Figure 3-9).

The relation was also applied to GRT and BER, lacking information.

3.4.3 Reservoir Temperature

The temperature for all three fields is taken to be 86.1 degC. This value is taken from the Bergermeer PVT spreadsheet, supplied by Taqa.

3.4.4 Contact picks; Saturation vs. Height

A list of GWC picks is given in Table 3-4. Comments indicate post-production dates, or other qualifications.

Saturation vs. height plots are shown in Figure 3-15, Figure 3-16,

Figure 3-17. Of the three fields, only GRT exhibits a relatively clear transition zone of the order of 40m. In the main field of the study, most wells do not show an obvious transition zone. There are some differences in the Sw level reached by the different wells, however; e.g. BGM3, which has the GWC in the (poorer) upper Rotliegend, has higher Sw levels, but does not show a clear Sw gradient.

3.4.5 Petrophysical Averages

Petrophysical averages from [1] are shown in Table 3-3. If we compare the average Sw (0.668) for BGM7 with Figure 3-13, we see that the average value given is the average Sw over the *whole Rotliegend, including the water leg*. Therefore these values cannot be used to populate the reservoir model.

We recomputed the averages. HC-only values are given in Table 3-4. It should be noted that there is a very significant spread in the data. Partially this is caused by the fact that the upper Rotliegend is poorer, and has higher Sw values. Thus wells penetrating only or mostly this part show higher Sw averages, than wells (like BGM1) that penetrate a larger part of the Rotliegend above the GWC.

Table 3-1 List of logs provided. The source of the logs is the work reported in [1]. The composite logs were loaded from the TNO/NITG DINO website. Core analysis results (conventional) was only available for well BGM1.

Well Name	Composite	Core Plugs	Log Code: GR	CALI	DEPTH	RHOB	NET	PHIE	VSH	BVW	DT	SW	VP	DRHO	RMED	RT	RS	RXO	SP	NPHI	NEUT	ILD	PEF
BER1			1	1	1	1	1	1	1		1	1	1		1		1	1					
BER2	1		1	1	1	1	1	1	1	1				1						1			
BER3	1		1	1	1	1	1	1	1	1	1	1	1	1		1				1			
BER4			1	1	1	1	1	1	1	1	1	1	1	1		1	1			1			
BGM1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
BGM2	1		1	1	1	1	1	1	1	1	1	1	1	1		1	1	1	1				
BGM3			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		1				
BGM4			1	1	1	1	1	1	1	1	1	1	1	1	1	1			1				
BGM5			1	1	1	1	1	1	1	1	1	1	1	1	1								
BGM6			1	1	1	1	1	1	1	1	1	1	1		1	1		1					
BGM6A			1	1	1	1	1	1	1	1	1	1	1		1	1		1					
BGM7	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1				1			
BGM8	1		1	1	1	1	1	1	1	1	1	1	1	1		1	1	1		1			1
BGM9	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			1			
GRT1	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		1		1		
GRT2	1		1	1	1	1								1	1				1		1	1	
GRT3	1		1	1	1	1	1	1	1	1	1	1	1	1	1								
GRT3A			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
GRT4	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
GRT5			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
GRT6			1	1	1	1	1	1	1	1	1	1	1		1	1	1	1	1				
GRT7	1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			

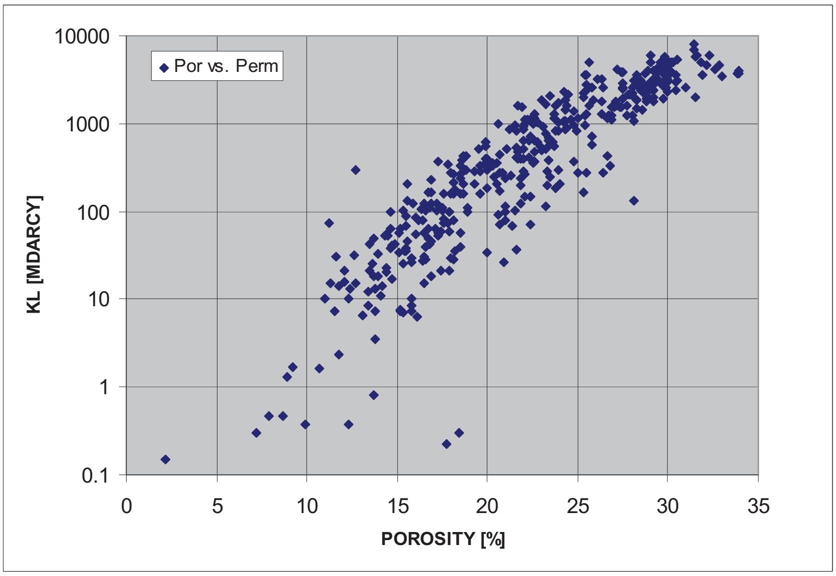


Figure 3-1 Por/Perm crossplot for BGM1 conventional core analysis

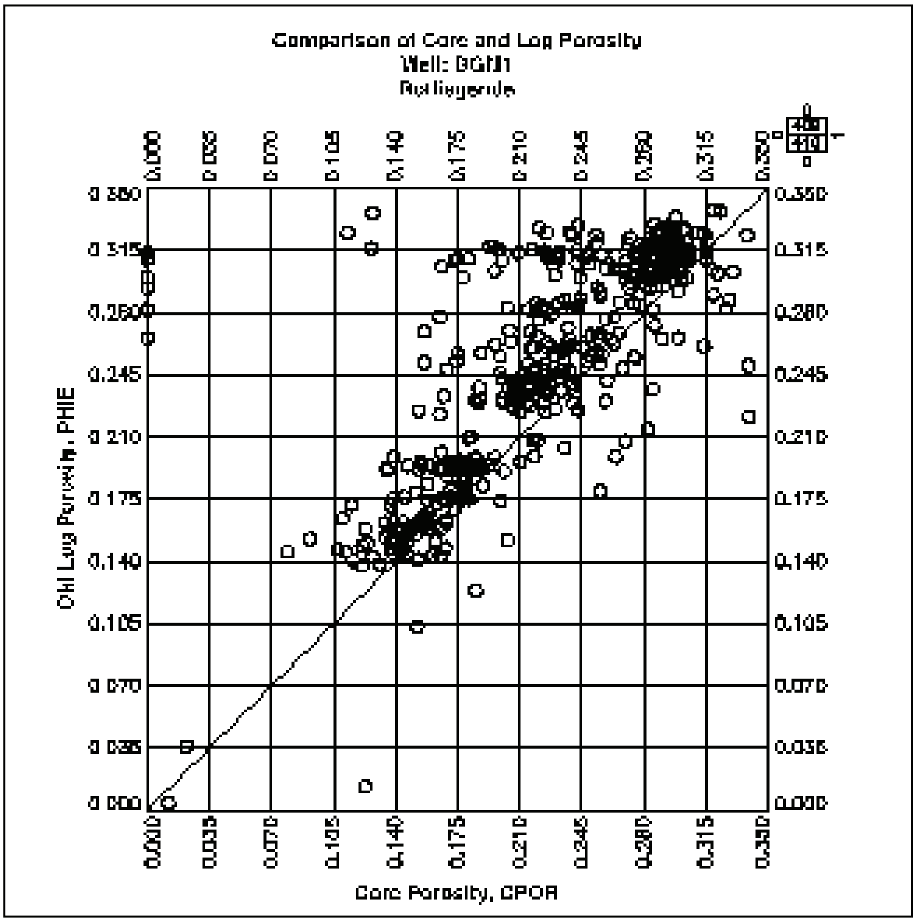


Figure 3-2 Core vs. log porosity (Figure 17 from ref. [1])

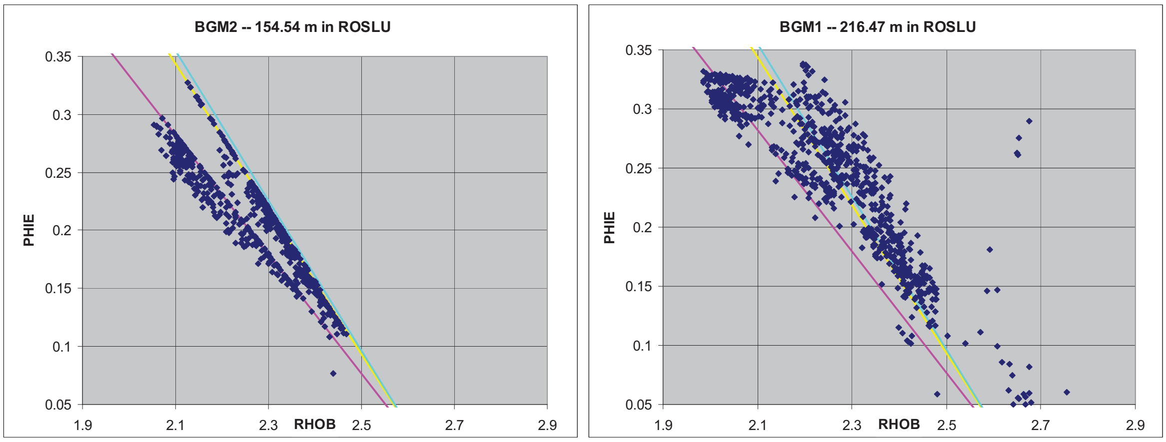


Figure 3-3 Crossplot of PHIE vs RHOB for BGM2 (left) and BGM1 (right). Trend lines plotted are for fluid densities 0.7 (purple), 1.05 (yellow), 1.1 (cyan), respectively. All trends use matrix density 2.65 g/cc.

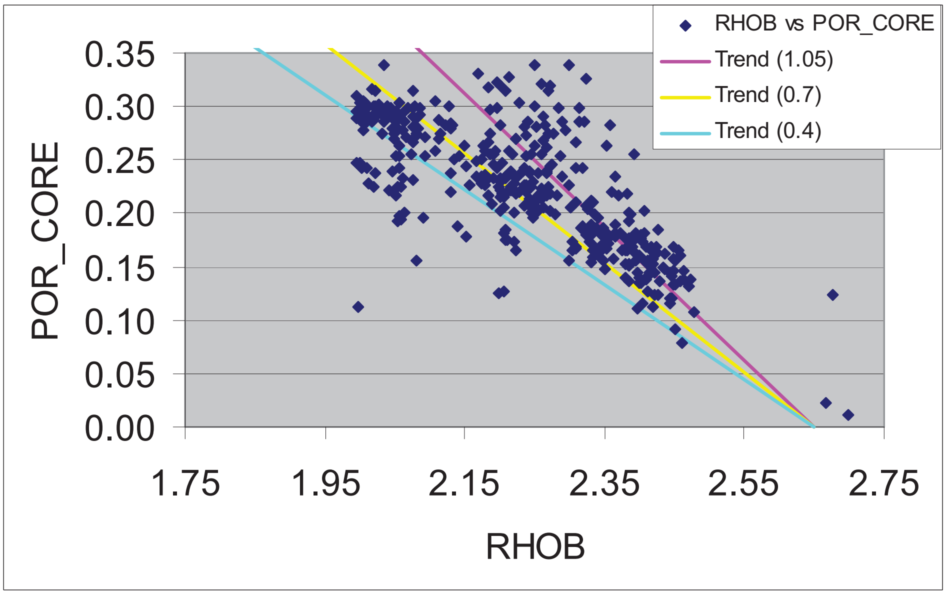


Figure 3-4 BGM1 cross-plot of core porosity (no attempt was made to achieve a core → log shift) vs. RHOB log values (last sample point preceding core plug depth). Various fluid density trends are superposed.

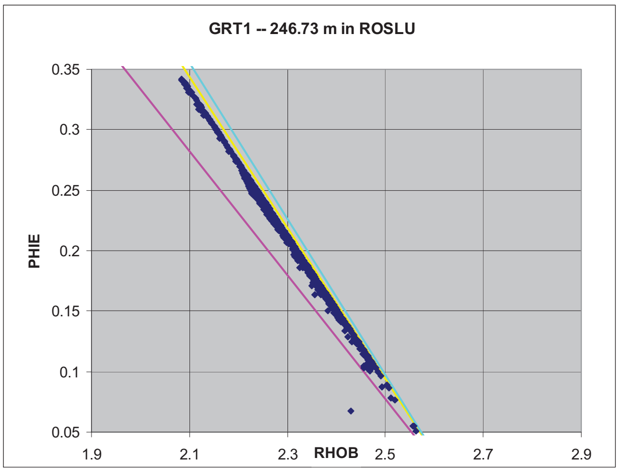


Figure 3-5 RHOB/PHIE crossplot for GRT1

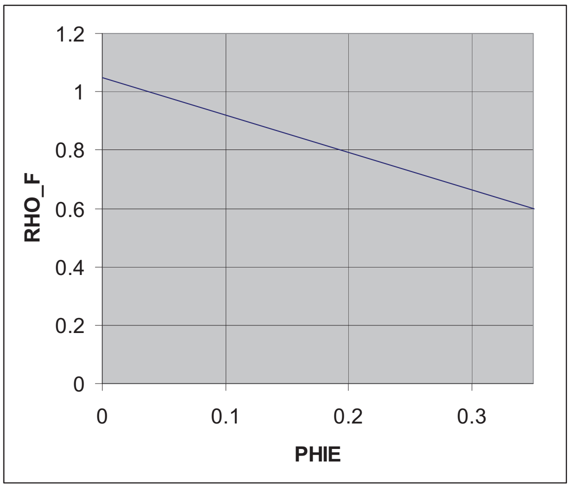
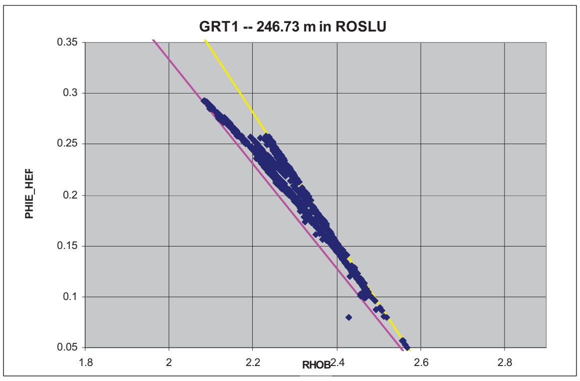


Figure 3-6 PHIE-ρ_f relation used in section 3.3 to model lower apparent fluid density at higher porosity.



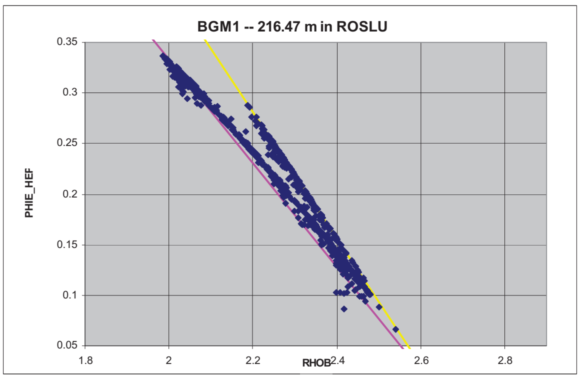


Figure 3-7 Density/porosity crossplot with adapted transform (left: GRT1, right: BGM1)

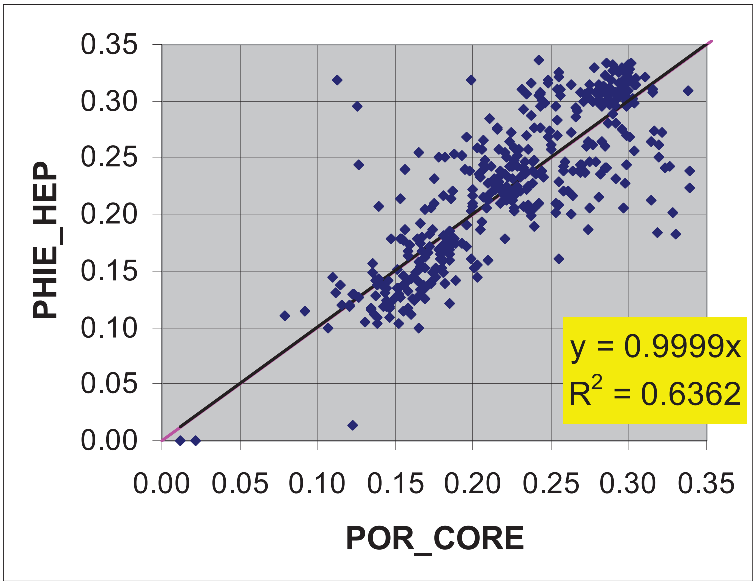


Figure 3-8 **Core/log crossplot of BGM1 with adapted density porosity log. Coefficients plotted are for a forced fit through (0,0). Note that the cloud of points around .18 is below the line (possibly suggesting higher matrix density), whereas the cloud around .28 is above the line (suggesting lower fluid density). The fit is of a similar quality than if we would have multiplied the input PHIE log (which was derived from porosity) by 0.9.**

Table 3-2 **Overview of wells in the project, with length of Rotliegend penetration (only BER1, BGM1 and BGM8A penetrate the base), as well as porosity (PHIE) log handling. Note that GRT porosity logs cannot be used as is, since no fluid fill correction was applied, not because they are based on the sonic log.**

Well Name	TVD Dist ROSLU [mTVD]	PHIE?	Comment
BER1	270	Do not use	Density is synthetic [PP report]
BER2	67	Replace	Log is DT-based
BER3	125	OK	
BER4	105	?	Unclear whether RHOB or DT is synthetic!?
BGM1	216	Replace	Log is DT-based
BGM2	155	OK	
BGM3	44	OK	Unclear
BGM4	47	OK	
BGM5	169	Replace	Log is DT-based
BGM6	49	Do not use	No density log run [PP]
BGM6A	148	Do not use	No density log run [PP]
BGM7	82	OK	
BGM8A	193	OK	
GRT1	247	Replace	Unclear; No fluid fill correction
GRT2	61	Replace	No fluid fill correction
GRT3	236	Replace	No fluid fill correction
GRT3A	155	Replace	No fluid fill correction
GRT4	195	Replace	No fluid fill correction
GRT5	99	Replace	Unclear; No fluid fill correction
GRT6	164	Do not use	Unclear whether RHOB or DT is synthetic!?
GRT7	101	Replace	Unclear; No fluid fill correction

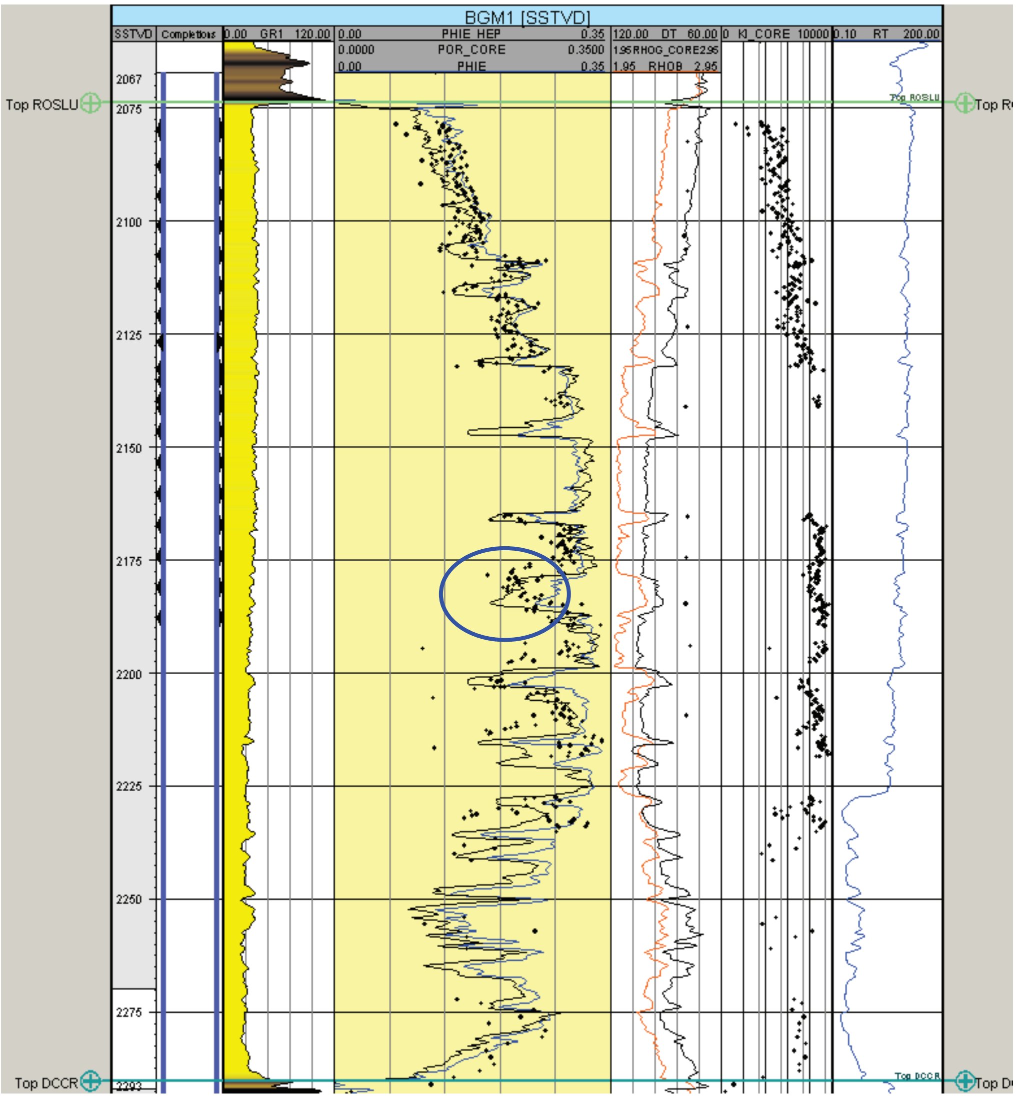


Figure 3-9 BGM1 log plot. The light yellow track shows the core porosity vs. the original PHIE (blue) and the adapted PHIE (black). The latter has generally slightly lower values, as well as more pronounced low-porosity streaks. The circle indicates an example of likely core/log depth mismatch.

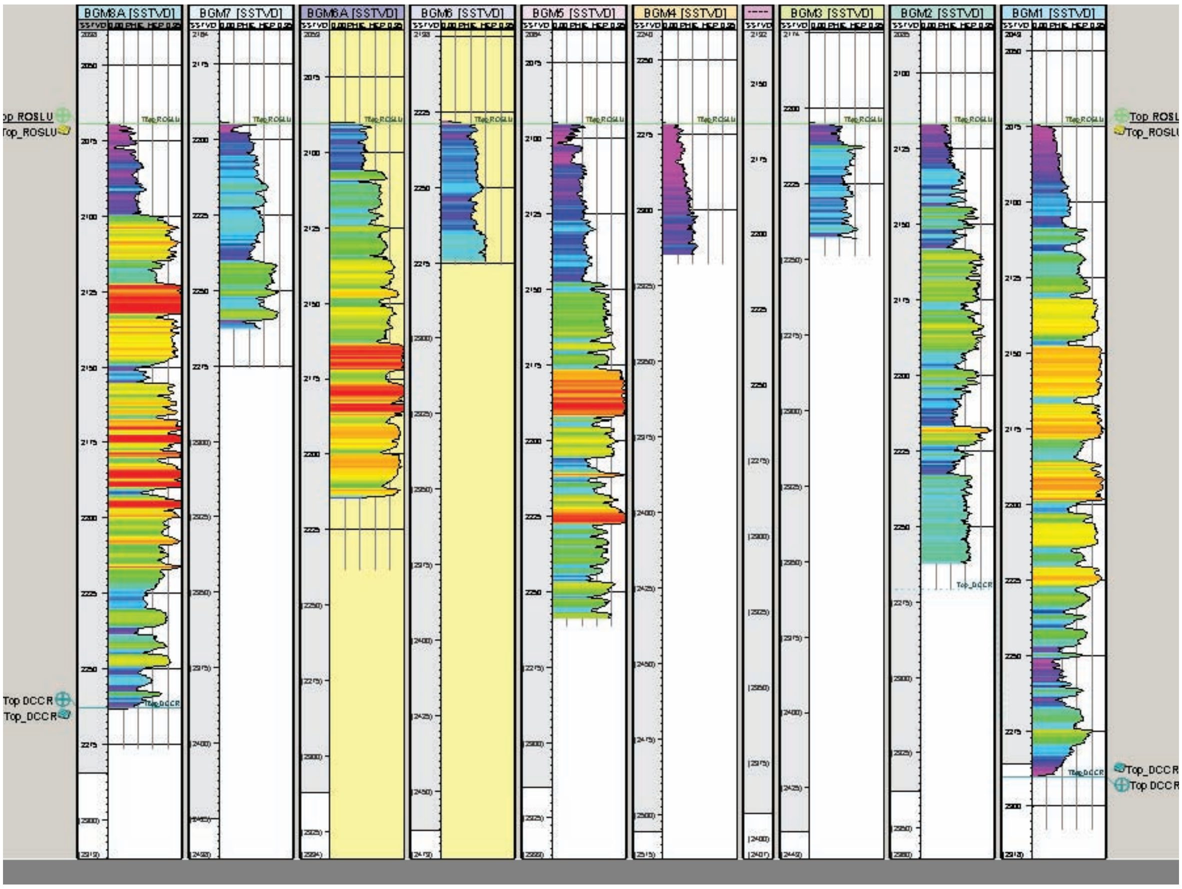
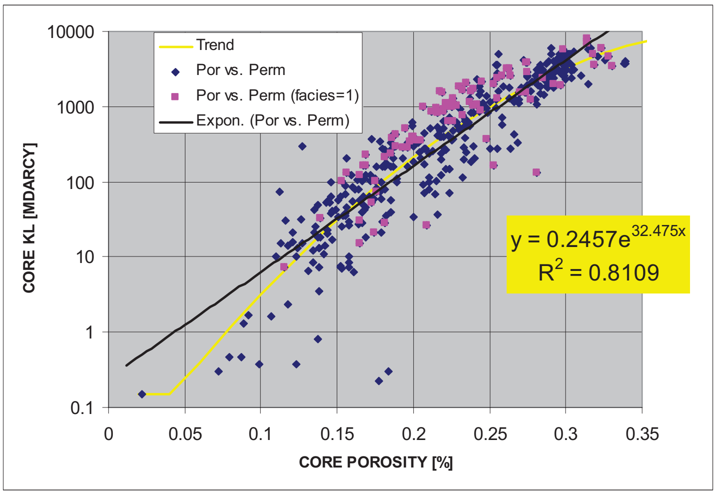


Figure 3-10 Partially (see Table 3-2) re-computed PHIE log plots for BGM8 (left) to BGM1 (right). PHIE scale is 0-0.34 for all logs. The BGM6 and 6A wells (which are not used for property interpolation; cf. section 4.4.4) are the third and fourth from the left (light yellow background).



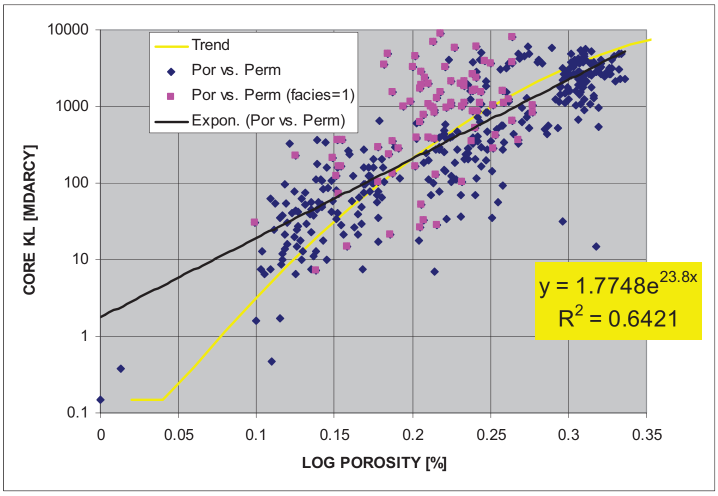


Figure 3-11 Por/Perm correlation wit linear and quadratic trend. The top plot shows core por vs. core perm, the bottom plot shows log por vs. core perm. The linear trend is fitted for the two graphs separately; the formulas are indicated in the graphs. The quadratic trend is fixed, as in the text.

Table 3-3 Petrophysical averages [1] of several fields in the Bergen concession. BGM and GRT are marked yellow; BER averages are not given.

Bergen Concession Area
Top Rotliegende Interval

(1) - not penetrated

Well	Depth	Net (m)	NTG	Phie * h	Phie	Sw	Gross	Tops
ALK1	2405.12	45.25	0.992	5.226	0.115	0.865	45.63	Top Rot.
BAC1	2044	34.5	1.000	6.346	0.184	0.644	34.50	Top Rot.
BGM1	2079.5	215.5	0.994	53.968	0.250	0.369	216.70	Top Rot.
BGM2	2481.5	169.25	0.944	35.157	0.208	0.394	179.36	Top Rot.
BGM3	2905.5	47.25	0.252	8.093	0.171	0.636	187.25	Top Rot.
BGM3A	2569							Top Rot.
BGM4	3287	46	0.939	5.116	0.111	0.982	49.00	Top Rot.
BGM5	2228	186.25	0.970	50.082	0.269	0.293	192.09	Top Rot.
BGM6	2344	48.75	0.939	8.257	0.169	0.793	51.91	Top Rot.
BGM6A	2205.5	128.75	0.817	34.320	0.267	0.159	157.50	Top Rot.
BGM7	3171.25	70.25	0.839	13.379	0.190	0.668	83.75	Top Rot.
BGM8	2125	193.5	0.997	47.493	0.245	0.301	194.00	Top Rot.
BGM9			0.000		0.000			Top Rot.
BKL1	3075.845	26.5	0.917	1.625	0.061	0.838	28.91	Top Rot.
BKM1								Top Rot.(1)
BKM1ST								Top Rot.(1)
BKM2								Top Rot.(1)
BKM3								Top Rot.(1)
BKM3ST								Top Rot.(1)
BKM4								Top Rot.(1)
BKM4ST								Top Rot.(1)
BKM5								Top Rot.(1)
BKM6								Top Rot.(1)
BKM7								Top Rot.(1)
BKM7ST								Top Rot.(1)
BKM8								Top Rot.(1)
BKM9								Top Rot.(1)
EGMB1	2685.85	211.1	0.998	44.094	0.209	0.000	211.51	Top Rot.
EGZ1	1663	28.75	0.991	4.986	0.173	0.978	29.00	Top Rot.
GRT1	2508	339.75	0.996	73.211	0.215	0.483	341.00	Top Rot.
GRT2								Top Rot.
GRT3	2454	43	1.000	4.987	0.116	1.000	43.00	Top Rot.
GRT3A	2254	152.5	0.981	28.062	0.184	0.645	155.40	Top Rot.
GRT4	2600	54.75	0.986	6.864	0.125	0.454	55.50	Top Rot.
GRT5	2623	24.75	0.980	2.475	0.100	1.000	25.25	Top Rot.
GRT6	2310	57	0.996	9.047	0.159	0.462	57.25	Top Rot.
GRT7	2826	106.75	0.979	18.495	0.173	0.894	109.00	Top Rot.

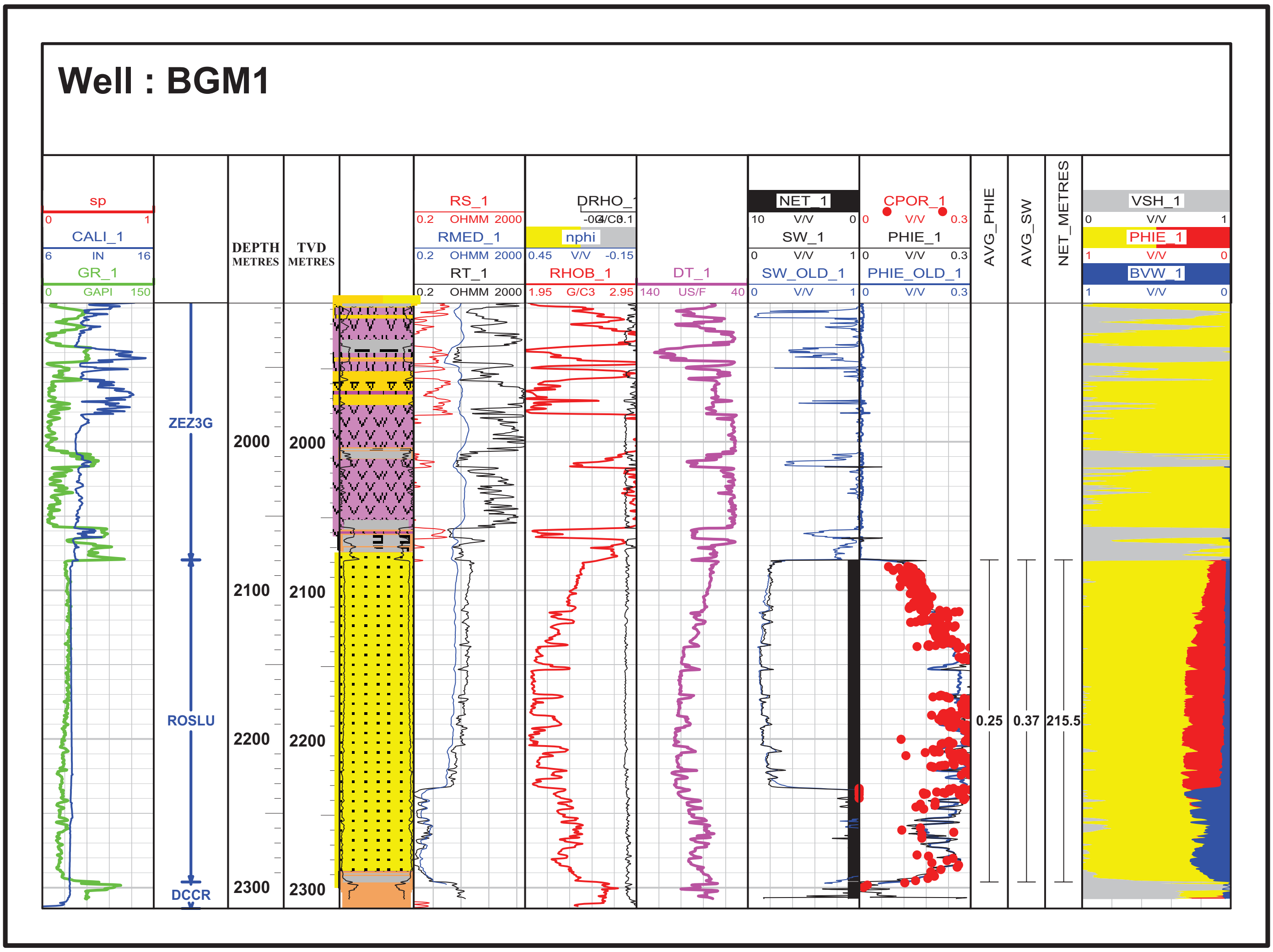


Figure 3-12 Log plot of well BGM1 across the Rotliegend (ROSLU) from [1].

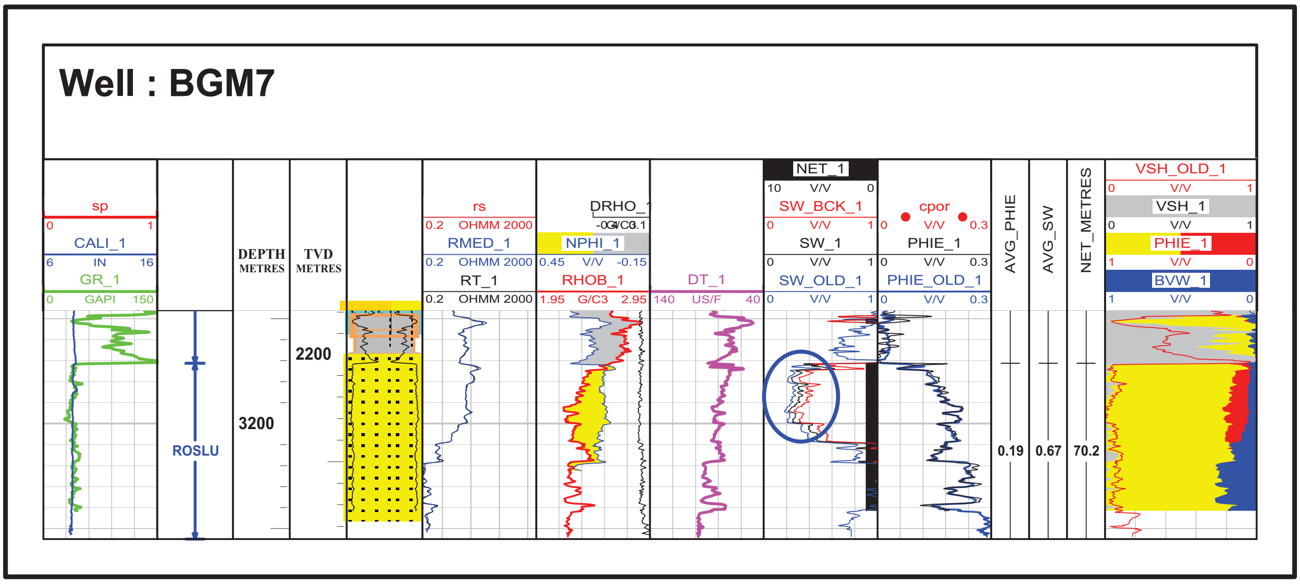


Figure 3-13 Log plot of well BGM7 across the Rotliegend (ROSLU) from [1]. The circle highlights the HC zone on the Sw track, with Sw's (visually) between 0.2 and 0.4.

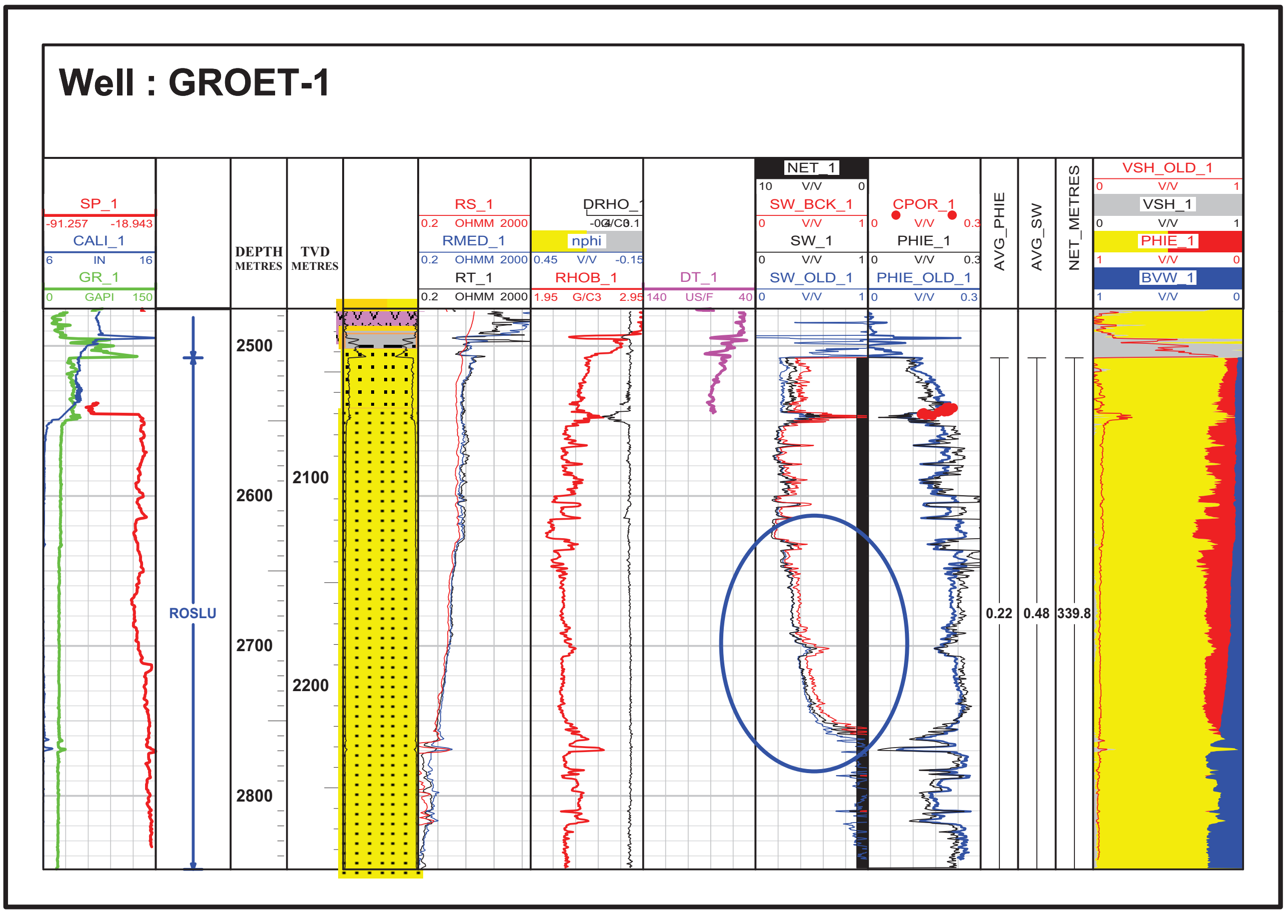


Figure 3-14 Log plot of well GRT1 across the Rotliegend (ROSLU) from [1]. The circle highlights the HC zone on the Sw track, with a ramping profile suggesting a transition zone.

Table 3-4 GWC picks from the various wells in the model. Swc averages obtained over the pay zone are also quoted [note that the Sw averages are not weighted with porosity or otherwise].

Well	**m SSTVD**	**Comment**	Sw mean
BER1	2143?	Sw does not go very low; different block	0.44
BER3	2134		0.43
BER4	2114??	Too (?) near TD	0.27
GRT1	2220		0.33
GRT3A	2218		0.47
GRT4	2221		0.43
GRT6	2228	Sw does not go very low	0.49
BGM1	2227		0.17
BGM2	2226		0.22
BGM3	2225		0.41
BGM5	2227		0.15
BGM6	-	Only water in ROSLU (Sw slope?)	-
BGM6A	-	Does not intersect GWC; TD @ 2213	0.17
BGM7	2231	Logged October(?) 1981	0.34
BGM8A	2217	Logged April(?) 1990	0.21

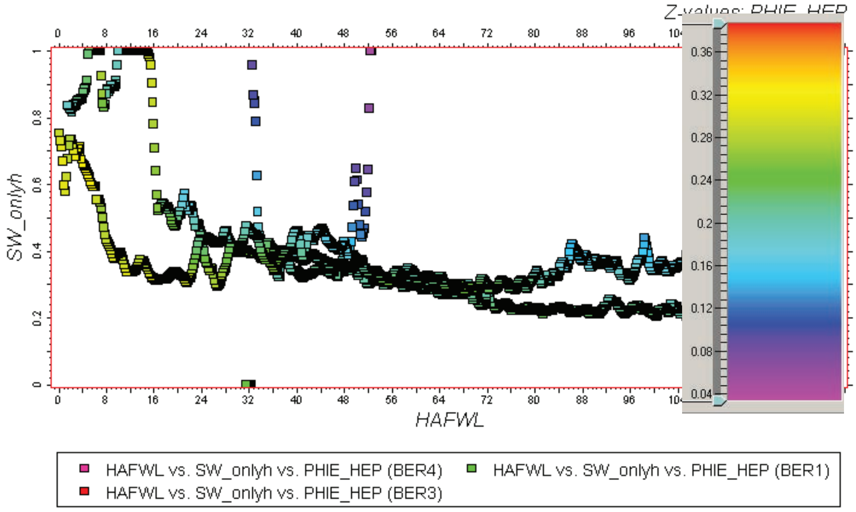


Figure 3-15 Saturation vs. height above free water level (FWL) for BER. Color is PHIE_HEP (0.03-0.39).

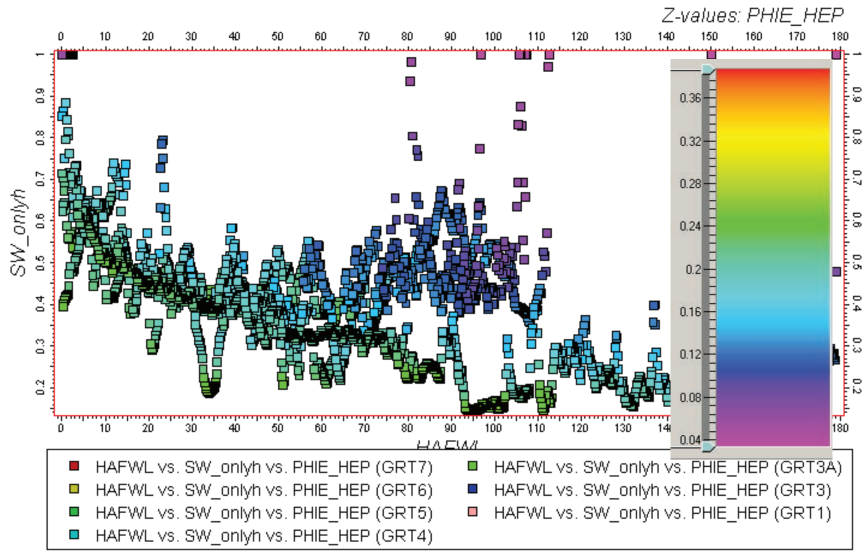
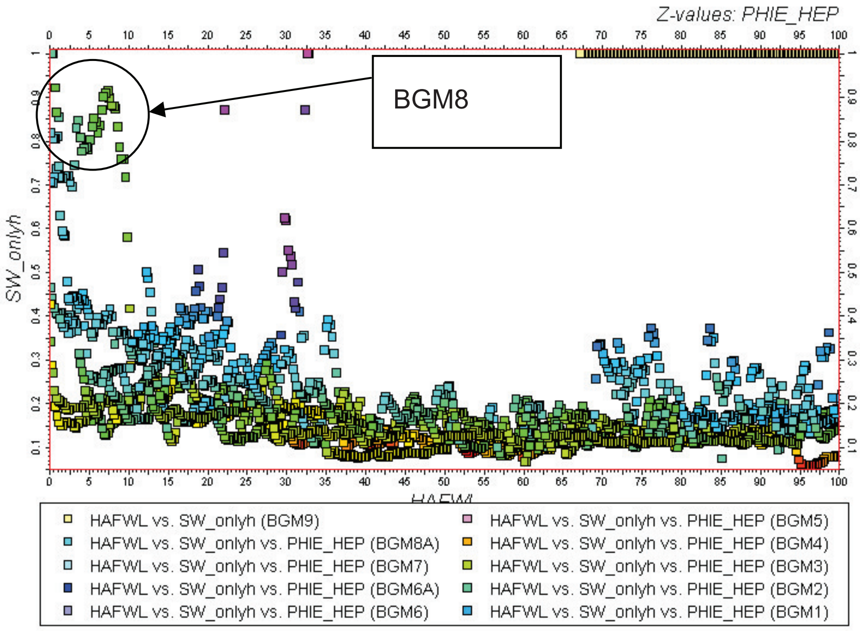


Figure 3-16 Saturation vs. height above FWL for GRT. Color is PHIE_HEP (0.03-0.39).



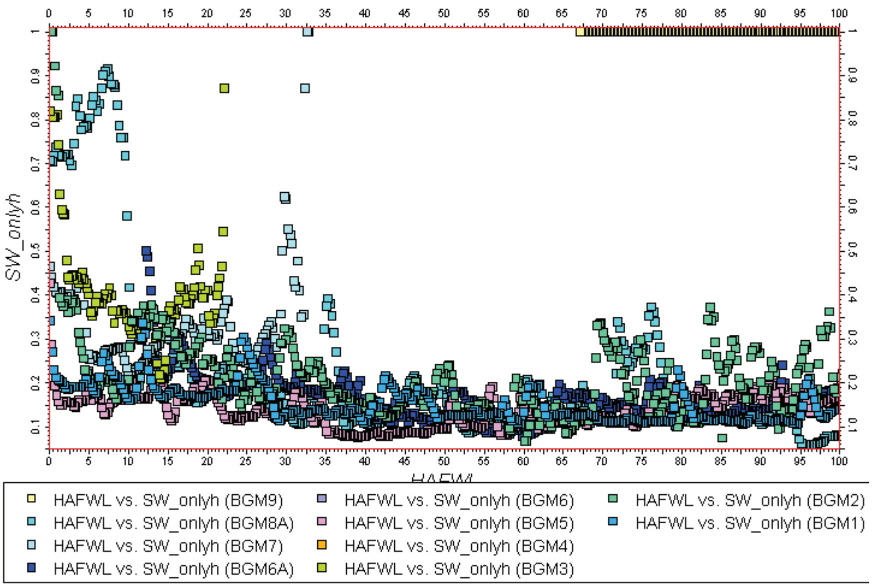


Figure 3-17 Saturation vs. height above FWL for BGM. Top: color is PHIE_HEP (0.03-0.39); bottom: colored by well. The well BGM8 is drilled later; the higher Sw's indicate a contact rise, not a transition zone.

4 Static Modeling

4.1 Input Data Overview

To execute this project, Taqa provided the following data:

- ☑ Well heads & trajectories for 23 wells
- ☑ Well tops (section 2.2)
- ☑ Well logs (LAS), and petrophysical report [1] (chapter 3)
- ☑ Seismic derived data Top ROSLU
- ☑ Seisimic/depth conversion derived ‘Top ROSLU’ uncertainty map
- ☑ Fault polygons
- ☑ ROSLU & Weissliegend TVDT maps
- ☑ Bergermeer map view with faults
- ☑ (Rough) BGM1 core description from 2084-2299 meters core depth
- ☑ Petrographic report (including thin section descriptions [10])
- ☑ Porosity logs (‘PHIE_Taqa’) from petrophysical analysis ([1]; chapter 3)
- ☑ Rotliegend thickness map

Moreover, the cores of BGM1, BGM2 (partial) and GRT3 were viewed on 14 March 2007

Composite logs were obtained from the TNO/NITG DINO site.

It should be noted that some data was not available for this study:

- ☑ Prior facies classification, or geological report
- ☑ Seismic seeds

4.2 Workflow

Below is a sketch of the modelling effort workflow that has been carried out in Bergermeer project and surrounding.