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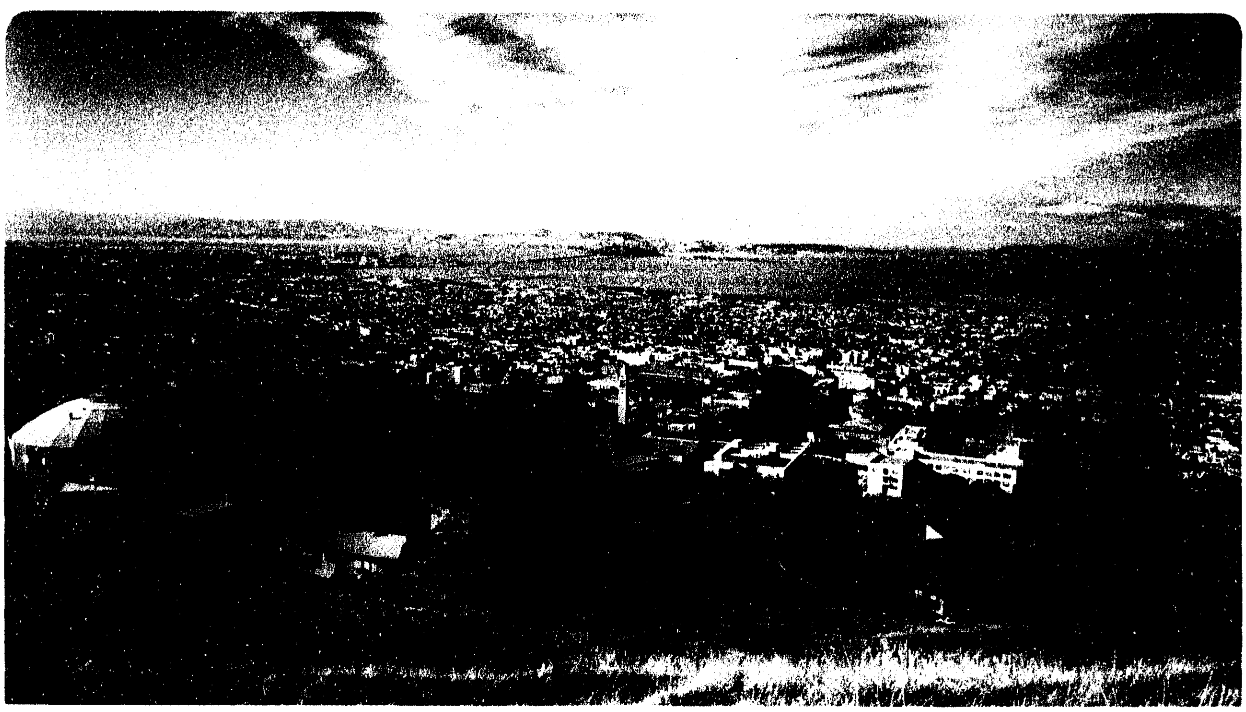
S. Finsterle

March 1994



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Inverse Modeling of Test SB4-VM2/216.7 at Wellenberg

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Abstract

Pressure and flow rate data from a water sampling test, which also produced gas, at the Wellenberg site are analyzed using inverse modeling techniques. Two conceptual models are developed and used for parameter estimation. The first model assumes that the gas observed at the surface is dissolved in the pore water under natural pressure and temperature conditions and comes out of solution due to the pressure reduction during pumping. The second model considers a mobile gas phase originally present in the formation. While both models are able to explain the observed pressure response as well as the gas seen at the surface, large uncertainties in the data and in the model assumptions inhibit the determination of two-phase flow parameters. The analysis indicates, however, that the formation has a very low permeability and that formation head is far below hydrostatic.

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1. INTRODUCTION

The objective of this modeling effort is to develop a conceptual model for analyzing the test WLB SB4-VM2/216.7, during which water and gas flow was observed at the surface. Hydrogeologic parameters are estimated based on the available pressure and flow rate data. Of special interest is the question whether the observed test response can be reproduced assuming single-phase liquid and/or two-phase flow conditions, and whether gas-related formation parameters (especially parameters for relative permeability and capillary pressure functions) can be obtained from these data. Furthermore, the performance of alternative conceptual models shall be examined in order to study the impact of the model structure on the estimated parameter set.

Given a conceptual model of the physical system, the quantification of aquifer parameters based on observations is referred to as *inverse modeling*. Model conceptualization and parameter estimation are strongly related in the sense that the parameter estimates obtained from inverse modeling may be meaningless if the conceptual model fails to account for the relevant processes controlling the system behavior. If the conceptual model does not mimic the correct physical behavior, it cannot be guaranteed that the estimated parameter set is a good characterization of the hydrogeologic situation in the field, even though a good match between observations and model predictions has been achieved. Such a model will fail in predicting system behavior under changed flow conditions. This type of error is difficult to identify and its minimization usually requires external information to be included in the analysis.

The parameter estimation problem is often suited to mathematical treatment and therefore of a more objective nature. Model conceptualization, however, requires identifying and approximating the salient features of the system which is based on an interpretation of the data and also on "soft" information about the formation and the test configuration as well as on an understanding of the hydraulic history of the tested rock body. It is, therefore, of a more subjective nature. As a consequence, the parameter set resulting from inverse modeling has to be critically reviewed in the light of the underlying conceptual model.

Solving the estimation-identification problem for the hydraulic test SB4-VM2/216.7 at the Wellenberg site is difficult and inherently uncertain due to the following reasons:

(1) The liquid and gas flow rate data as well as the pressure data are incomplete and exhibit a great deal of uncertainty
(2) Initial conditions (borehole history) and boundary conditions in the borehole are not well known
(3) The exact configuration of the test system is not clearly enough documented
(4) The data are not sensitive enough to reliably estimate two-phase flow parameters

The difficulties refer to both model conceptualization and actually backcalculating parameter values from the available data set. It will be shown that important target parameters (such as the gas saturation in the Valanginian Marl) cannot be identified because the underlying conceptual model remains uncertain. Alternative models give different answers to the question whether there is free gas in the formation or not.

However, the analysis of the test sequence using the ITOUGH2 code [*Finsterle*, 1993] allowed studying some of the processes that may be significant when interpreting data from the Wellenberg boreholes. The system behavior exhibits two-phase flow effects which can qualitatively be reproduced by the numerical model. Exact matching of the pressure data could not be achieved. The borehole configuration, the flow data and the overall system behavior are too uncertain to extract reliable information about the two-phase hydraulic properties of the formation.

In this report, we will first review the data and their uncertainty and describe the process of model development. Two conceptual models will be introduced. The first assumes that the formation is essentially liquid saturated. Pressure lowering due to pumping causes the dissolved gas in the pore water to come out of solution. The second conceptual model considers a free gas phase which is initially present in the formation. The solution of the direct and inverse problem will be presented, and the estimated parameter set will be critically discussed.

2. REVIEW OF DATA

2.1 PURPOSE

The purpose of the data review is to:

(1) gain insight into the system behavior
(2) evaluate the quality of the data
(3) detect systematic errors
(4) find evidence for a proposed conceptual model or its alternatives

Recall that the data will be used for model calibration. While *random errors* in the data can be statistically described and are part of the mathematical formulation, any *systematic error* in the data will bias the results obtained by inverse modeling. A major source of systematic errors is the test equipment as well as uncertainties in the test configuration, and flaws in the conceptual model. The numerical model will calculate pressures and flow rates at the interface between the formation and the borehole. Any artifact which is not explicitly modeled will result in biased estimates. In our case, for example, the gas flow rate observed at the surface does not correspond to the one calculated downhole under ambient pressure and temperature conditions. The data have to be corrected in order to account for degassing effects during the rise of water in the borehole.

Only a limited amount of information about the test was available for this modeling study. An excerpt of the Quick Look Report by Ostrowski and Kloska [*QLR*, 1993, see Appendix B] was faxed to LBL, including some personal remarks by O. Jaquet (Colenco Power Consulting AG). Pressure as well as gas and liquid flow rate data were electronically transferred (see Figure 1 below). Based on this information, it was difficult to assess the actual test configuration and the precise meaning of the individual data. This uncertainty, which will be discussed in detail below, allows only for a very simplified model conceptualization as described in Section 3.

2.2 PRESSURE AND FLOW RATE DATA

"The main objective of the interval test SB4-VM2/216.7 was water sampling. *Therefore, no attention was paid to maintain the inner boundary condition of constant rate or pressure.* The presence of gas, but first of all the test sequence planned only towards the maximizing the production rate *made the pressure data difficult for analysis* (...)." [*QLR*, 1993, emphasis added].

This statement reflects itself in the flow rate and pressure data which are difficult to interpret as a consistent response from the test interval. For example, gas and liquid flow rates are monitored during the RWS1 period (for abbreviations see Glossary), where no flow is expected according to the definition of a shut-in recovery period. Even though these flow rates are relatively low, they are comparable to the ones observed at the end of the actual pumping period RW1.

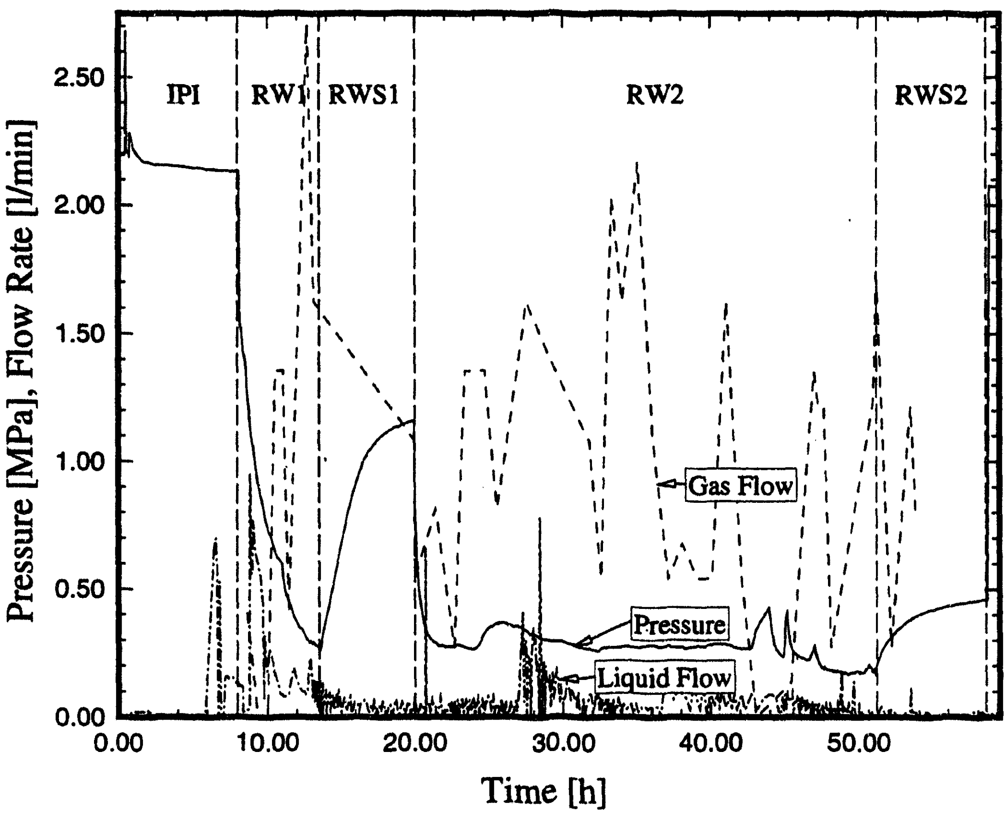

Figure 1: Pressure, gas and liquid flow rate data

"The total water volume produced at the surface is about 0.11 m^3 since due to the storage of the system above the shut-in tool water was still flowing during the RWS1 period" [*QLR*, 1993, Legend]. Given this information, it is difficult (if not impossible) to clearly distinguish between the inflow to the actual test interval and additional flow from "the system above the shut-in tool". Similarly, an almost constant pressure period during the first 8 hours of the test is not reflected in an appropriate injection rate. On the other hand, if interpreted as a pressure recovery period, flow rates should be zero. The inconsistency may be partly unraveled by the following remark: "At the beginning of the PSR period (the) *shut-in tool was not closed properly* when filling up the system" [*QLR*, 1993, Legend, emphasis added]. The pressure thus reflects the water level in the borehole above the shut-in tool rather than the static formation pressure.

The significant increase of liquid flow rate between t=27 h and t=29 h is not seen in the pressure response. It remains questionable, whether this behavior can be clearly attributed to two-phase flow effects in the formation or in the borehole, respectively.

The pulse injection IPI is not recorded at all, and the rate of 15 l/min given in *QLR* [1993, Legend] seems to be unrealistically high (for details see below). Finally, no explanation is given for the final instantaneous pressure increase at the end of period RWS2 which may be caused by the opening of the injection valve or by stopping the pump.

In summary: While the anticipated test sequence (INF, PSR, IPI, RW1, RWS1, RW2, RWS2) is partly reflected in the pressure data, the corresponding flow rate record is not consistent or difficult to interpret due to the unknown test configuration (leaking of shut-in interval, flow from the system above the shut-in tool, misleading reporting etc.). A clear correlation between flow rate and pressure data is essential for performing inverse modeling since systematic errors will result in a bias of the estimated parameter set. In this study, we will rely on "soft information" found in the Quick Look Report rather than on the flow rate data measured at the surface (see Section 3).

2.3 WELLBORE STORAGE COEFFICIENT

The wellbore storage coefficient is an important quantity for interpreting pump tests. System compressibility values from different sources are compared in order to check their consistency.

(1) QLR: Preliminary information: "$c_t = 4.42 \cdot 10^{-10}$ Pa^{-1} (assumed c_t=c_w)". Here, c_t is the total system compressibility, and c_w is water compressibility.

(2) QLR, Footnote 3: "Pressure impulse lasted 30 s with an injection rate of 15 l/min. This resulted in pressure increase of 83 kPa." From this, the wellbore storage coefficient C is calculated to be as high as $9 \cdot 10^{-5}$ m^3/Pa. The question whether 15 l/min is a typing error (15 ml/min seems to be more realistic) cannot be answered because the data actually show a zero flux.

(3) QLR, Footnote 5: "C calculated from injection data is $9 \cdot 10^{-8}$ m^3/Pa". In the corresponding Table, C is $6.5 \cdot 10^{-8}$ m^3/Pa.

(4) QLR: C = $2 \cdot 10^{-9}$ m^3/Pa during RW1, $9 \cdot 10^{-10}$ m^3/Pa during RW2, and $1.9 \cdot 10^{-8}$ m^3/Pa during RWS2; no value is given for RWS1.

(5) Jaquet [Appendix B] uses $c_\phi = 2 \cdot 10^{-9}$ Pa^{-1} which corresponds to $C = c_\phi \cdot \phi_w \cdot V_w$ = $2.9 \cdot 10^{-10}$ m^3/Pa, where c_ϕ is a pore space compressibility, ϕ is porosity and V_w is the volume of the packed-off interval.

(6) QLR Comments: "High compressibility of the system suggested the presence of gas in the test interval. (...) (T)he amount of gas produced proved that there was (...) free gas in the test interval."

In summary, the reported values for the wellbore storage constant C range from $9 \cdot 10^{-5}$ to $2.9 \cdot 10^{-10}$ m^3/Pa! A more reasonable range (assuming that the highest value is a typing error and the lowest value results from a misunderstanding of c_ϕ) is $9 \cdot 10^{-8} > C > 9 \cdot 10^{-10}$ m^3/Pa.

In this study, we will treat the wellbore storage coefficient as an unknown parameter to be estimated by inverse modeling. If the wellbore storage coefficient turns out to be unreasonably high so that it cannot be attributed to the compressibility of the water in the borehole and the compressibility of the equipment (system compliance), it is assumed that a certain amount of free gas is trapped in the borehole.

2.4 INITIAL PRESSURE

In this section, the values given for the "Estimated Static Pressure" [*QLR*, 1993, Prel. Info.] are reviewed. The formation pressure is important as one of the target parameters. Furthermore, it determines the maximum amount of gas being dissolved in the pore water under natural conditions (assuming equilibrium according to Henry's law) and therefore provides an upper limit for the gas flow rate observed at the surface, if the formation is assumed liquid saturated. The terminology used for this parameter is somewhat confusing. We assume that the following expressions are equivalent: "estimated static pressure", "initial pressure", "static pressure", "hydraulic head", "formation pressure". In our view, the target measure is the *"pressure in the closed off interval, P_2, under equilibrium conditions"*. The following estimates are given:

(1) QLR: 2044 kPa at P_2 (from SB4-VM1/??).

(2) QLR: 962.6 m a.s.l. from static pressure recovery period. This is equivalent to a pressure of 2132 kPa at P_2.

(3) QLR: 960.0 m a.s.l. from Horner extrapolation (freshwater equivalent, corrected for borehole inclination of 15°)

(4) O. Jaquet: 1646 kPa (Colenco estimate from welltest analysis)

(5) Surface altitude is 958.3 m a.s.l. Previous investigations reported a low pressure zone associated with part of the Valanginian Marl at WLB [*Vinard & McCord*, 1991]

In this study, the value of the initial, uniform gas pressure at P_2 is considered an unknown parameter to be estimated by inverse modeling.

2.5 GAS SATURATION

Previous investigations at the Oberbauenstock and Wellenberg sites indicated that there might be a free gas phase present in the Valanginian Marl [*Andrews*, 1988; *Vinard & McCord*, 1991]. However, the gas saturation under natural flow conditions has never been quantified. Furthermore, the formation was assumed liquid saturated in most of the test interpretations and modeling studies performed so far. If the formation is assumed saturated with water, the free gas shown at the surface are considered artifacts of the testing, i.e. the pressure reduction due to pumping caused dissolved gas to come out of solution. Both conceptual models (single-phase liquid and two-phase gas-liquid) are investigated in this study. The pressure response from the test SB4-VM2/216.7 may support one of the two basic assumptions concerning the natural gas content at Wellenberg. The following statements are indicative for the presence of a free gas phase:

(1) Mean gas flow rates of $1.3 \cdot 10^{-5}$ and $1.7 \cdot 10^{-5}$ m^3/s were measured at the surface during RW1 and RW2, respectively [*QLR*, 1993].

(2) "High compressibility of the system suggested *the presence of gas* in the test interval. (...)*The presence of gas* (...) made the pressure data difficult for analysis (...). *The changing (not determined) saturation conditions* at the borehole face allow only rough estimation of water effective permeability (...). It is interesting to note that the amount of gas produced *proved that there was* (...) *free gas* in the test interval." [*QLR*, 1993, Comments, emphasis added]

(3) Preliminary calculations by O. Jaquet indicate an initial gas saturation of 54 % (porosity is assumed 1 %).

Note that permeability estimates are calculated assuming single-phase liquid conditions. In this study, the initial gas saturation for the two-phase model is considered an unknown parameter to be estimated by inverse modeling.

2.6 BOREHOLE HISTORY

Borehole history is important to determine initial pressure and saturation distribution. It may also help understand borehole conditions during testing.

(1) QLR: Intersect top of zone on 16.06.90 at 14:00, bottom on 16.06.90 at 18:55, mud pressure: 3 - 4 bar (head)

(2) QLR: Summary of test events/results: Bh. History Effect: NO

(3) QLR: "This difference (in the estimated static pressure) is most probably caused by borehole pressure history."

In this study, the borehole history is simulated as a constant pressure water injection test (see Section 3). Although not actually representing the borehole history during drilling and previous testing, this approach allows estimating the initial pressure and saturation distribution. The fact that borehole history creates a liquid-saturated zone around the well is an important feature which explains the system behavior in the two-phase environment. It yields a composite system in terms of its radial phase composition (Model B, see below) or with respect to the dissolved gas content in the vicinity of the borehole (Model A).

3. CONCEPTUALIZATION

The aim of the model conceptualization is to represent the salient features of the flow system during test SB4-VM2/216.7. No exact reproduction of the observed pressure or flow rate data can be expected due to the uncertainty described in Section 2. Consequently, the degree of details with which the model is conceptualized is limited. The following test sequence is modeled: borehole history (BH; includes period INF, PSR, and IPI), constant rate withdrawal test (RW1), pressure recovery (RWS1). The test periods RW1 and RWS1 are used for calibration.

The test is conceptualized as follows:

(1) The flow regime is radial; formation thickness is 5.85 m; borehole volume between the packers is 0.146 m^3.

(2) The formation is assumed homogeneous with respect to its hydraulic properties; porosity is 1 %; isothermal conditions are assumed at a temperature of 14 °C. Recall that the system becomes composite, however, in terms of its initial phase composition due to drilling fluid invasion and various pretest activities.

(3) Two models are considered with different assumptions regarding the origin of the gas observed at the surface:

Model A: The formation is initially liquid saturated. The water is saturated with dissolved gas according to Henry's law at ambient pressure and temperature conditions (initial pressure to be determined). Gas comes out of solution due to pressure lowering.

Model B: The formation contains a free gas phase (initial pressure and gas saturation to be determined).

(4) Borehole history and initial test sequence (INF, PSR, IPI) are modeled as a constant pressure water injection test; injection pressure is 2130 kPa; test duration is 8.11 h. Two cases are considered concerning the amount of dissolved gas in the water which is injected during the initial period. In the first case it is assumed that no gas is dissolved (*Case nDG*). The second scenario assumes that injection pressure is maintained by means of a gas pressure source, leading to a maximum of dissolved gas in the injection fluid at a bubbling pressure of 2130 kPa (*Case DG*). A similar effect occurs if gas that is

trapped in the borehole gets dissolved while being compressed. The high wellbore storage coefficient may indicate that a free gas phase was present in the borehole. On the other hand, injection may be too fast to reach equilibrium between air partial pressure and dissolved air.

(5) Test sequence RW1 is modeled as a constant rate withdrawal test. Production rate is $-2.2 \cdot 10^{-3}$ kg/s (from *QLR* [1993, revised Table]); test duration is 5.53 h. The ratio of water and gas produced in the well is automatically determined by the mobility ratio of the liquid-gas mixture in the vicinity of the borehole.

(6) Test sequence RWS1 is modeled as a shut-in recovery period. Test duration is 6.34 h.

(7) Three sets of characteristic curves (relative permeability of liquid and gas, and capillary pressure as a function of liquid saturation) are considered:

Curve L: Gas and liquid relative permeability are linear functions of gas and liquid saturation, respectively. Capillary pressure is a linear function of liquid saturation.

Curve VG: Van Genuchten's model describes a consistent set of capillary pressure and relative permeability functions [*Luckner et al.*, 1989]. There is strong interference between the gas and the liquid phase, resulting in $k_{rl} + k_{rg} < 1$.

Curve VGm: Capillary pressure and liquid relative permeability k_{rl} are calculated according to the equations given by *Luckner at al.* [1989], and gas relative permeability is $k_{rg} = 1 - k_{rl}$. This modification of Model VG represents a medium with no phase interference between gas and liquid.

(8) The following parameters are estimated based on the data from the RW1 and RWS1 test periods:

Model A
- logarithm of absolute permeability log(k)
- logarithm of matrix compressibility $\log(c_m)$
- logarithm of borehole compressibility $\log(c_{bh})$
- initial gas pressure (p_0)

Note that no parameters of the characteristic curves are estimated for Model A. Sensitivity coefficients have been calculated, indicating that these parameters cannot be determined from the available data set. The very low sensitivity is mainly due to the fact gas saturation does not exceed 1 %.

Model B

- logarithm of absolute permeability log(k)
- logarithm of borehole compressibility log(c_{bh})
- initial gas pressure (p_0)
- initial gas saturation (S_{g0})
- parameter n of van Genuchten's characteristic curves (Model VG and VGm)
- parameter $1/\alpha$ of van Genuchten's capillary pressure function (Model VG and VGm)
- parameter $P_c(S_l{=}0)$ (Model L)

(9) The parameters are determined by inverse modeling. The P_2 pressure data are sampled at 30 points in time between t = 8.11 h and t = 19.98 h (RW1 and RWS1). The a priori standard deviation is 10.0 kPa. Prior information about the parameters is not weighted. In addition to the pressure transducers, a phase separator was installed at the surface to independently measure gas and liquid flow rates. The gas flow rate was strongly fluctuating during the pumping period which may be caused by the coalescing of gas bubbles while uprising in the borehole. The total amount of gas produced during the RW1 period was determined to be 0.270 sm^3 [*QLR*, 1993, revised Table]. This includes gas that is originally dissolved in the water at downhole conditions, and which comes out of solution while being depressurized at the surface. In order to obtain the corresponding TOUGH2 result, the gas flow rate at downhole pressure conditions is integrated over time. The amount of dissolved gas entering the borehole in the liquid phase is calculated, and the difference to the gas content in the liquid phase at standard conditions is obtained. This yields the mass of air coming out of solution when being depressurized. The total gas mass is finally transformed to the corresponding volume at standard conditions. This measure, i.e. difference between observed and model predicted gas production is appropriately weighted and added to the objective function for inverse modeling.

The calculations are performed on an IBM RS/6000 workstation at LBL using the ITOUGH2 code [*Finsterle*, 1993]. Samples of a TOUGH2 and ITOUGH2 input file are shown in Appendix A1 and A2, respectively.

4. MODELING RESULTS

4.1 ANALYSIS PROCEDURE

The conceptual models outlined in Section 3 include different assumptions about the initial phase composition in the formation, saturated (Model A) vs. unsaturated (Model B). They comprise three types of characteristic curves, linear functions (Curve L), van Genuchten's functions (Curve VG), and modified van Genuchten's functions with $k_{rg}=1-k_{rl}$ (Curve VGm). Finally, the amount of dissolved gas in the fluid injected during the initial period has been varied. In Case nDG, no dissolved gas is present, and in Case DG, a maximum amount of gas is dissolved in the borehole fluid.

Combining all these options results in 12 conceptually different models to be investigated. An inverse model is set up for each conceptualization, and best fit parameter sets are determined. An individual model is considered satisfying if the variance of the final residuals does not significantly deviate from the anticipated accuracy. This can be statistically tested by the Fisher model test. The performance of models with different structures is evaluated by means of Kashiap's model identification criteria which measures goodness of fit, number of parameters, and parameter sensitivity (for details see *Carrera and Neuman* [1993]).

It is interesting to note that **all models are able to reproduce the pressure response fairly well**, leading to different estimates of the hydraulic parameters. However, **some of the models fail to reproduce both the pressure response and the total amount of gas being produced at the surface**. For example, the model A/VG/nDG matches the pressure data well, but underestimates the total gas volume. Consequently, no satisfying model performance can be achieved if gas production is added to the objective function. Similarly, model B/VGm/DG fits the pressure data only if gas production is allowed to greatly exceed the one observed in the field.

Four models were eventually able to pass the Fisher model test. If the formation is liquid saturated, and degassing is the main mechanism for gas production (Model A), van Genuchten's characteristic curves with increased gas mobility (Curve VGm) are required to explain that free gas is observed at the surface. As an alternative, if the formation contains a free gas phase (Model B), strong phase interferences as described by van Genuchten's original functions (Curve VG) are needed in order to obtain a good fit between the observed and calculated pressures and gas volumes.

The system behavior for the four successful model structures (Models A/VGm/nDG, A/VGm/DG, B/VG/nDG, and B/VG/DG) is described in Section 4.2. The resulting parameter sets are discussed in Section 4.3.

4.2 DIRECT PROBLEM

4.2.1 MODEL A: DISSOLVED GAS

In Model A, the formation is initially fully liquid saturated, i.e. there is no free gas phase in the pore space. However, gas may be dissolved in the liquid phase. The maximum amount of gas being dissolved is given by Henry's law, based on the local equilibrium assumption. By reducing the pressure or increasing the temperature, gas comes out of solution and forms a free phase. The pressure at which degassing occurs is sometimes termed bubbling pressure. Even though the formation is initially fully liquid saturated, two-phase characteristics determine the flow of the individual phases toward the pumping well after degassing. Due to the limited amount of gas being dissolved in the pore water, only a low gas saturation is expected for this scenario. Therefore, a high relative permeability is required to allow gas flowing toward the pumping well. This is achieved by modifying van Genuchten's characteristic curves such that no strong phase interferences occur by setting $k_{rg} = 1 - k_{rl}$. As previously mentioned, the gas observed at the surface cannot be explained using van Genuchten's standard model or linear functions.

Since the water around the borehole is mainly fluid that was injected during the various pretest activities, the amount of dissolved air in this water is of importance. Two extreme cases (Case nDG and DG) are tested in this study.

Figure 2 shows a comparison between observed and calculated pressures in the borehole as a function of time for Model A/VGm. The measured data are represented by symbols. The solid line is the model result for the case where no gas is dissolved in the injection fluid, and the dashed-dotted line represents the case where the injection water is saturated with dissolved gas at a bubbling pressure of 2130 kPa. Even though the pressure response is equally well reproduced by both models, the system behavior is slightly different, leading to different optimal parameter sets.

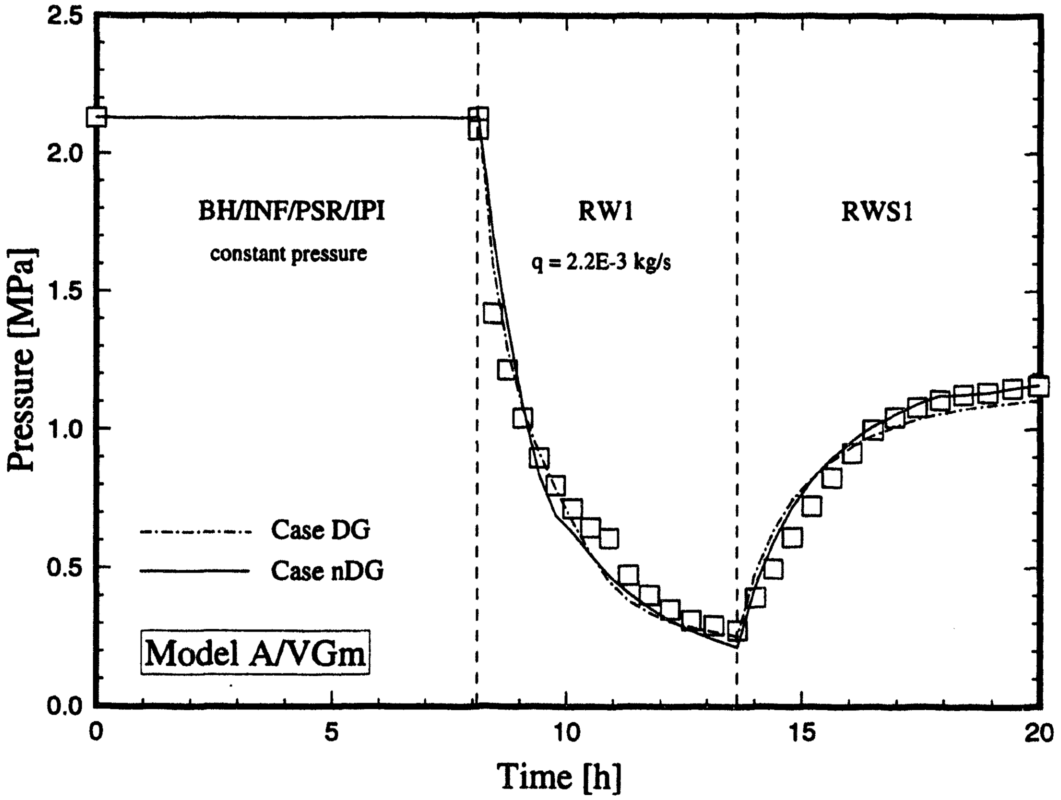

Figure 2: Model A/VGm: Comparison between observed and calculated pressure response

The system behavior can be described as follows:

- The injection of water during the initial test sequence creates a zone around the borehole which is saturated with injection water. Formation water is displaced up to a radial distance of about 2.5 m. The pressure disturbance has propagated about 20 m into the rock.

- Subsequently, fluid is produced at a prescribed rate, leading to a pressure decline in the well and in the formation. Note that at a certain distance from the well, the groundwater is overpressured with respect to the initial pressure; close to the well, however, it is underpressured after a relatively short pumping period.

- Case nDG: Since the water around the well mainly consists of injection water which does not contain dissolved air, gas comes out of solution further outward where the pressure drops below the bubbling pressure of the pore water. In our case, a free gas phase evolves after about 1 hour of pumping at a radial distance of 0.5 m. A ring is formed at a certain distance from the borehole where degassing occurs. This ring of gas expands in both directions, outwardly and inwardly. The outer boundary is defined by the contour where the formation pressure equals the bubbling pressure of the pore water. The inner boundary is defined by the interface between the formation water and the injection water. As a result, the propagation of the inner interface between liquid and gas is dominated by advective flow toward the borehole, whereas the velocity of the outer interface is governed by the velocity of the pressure pulse. This process only occurs if the pressure in the wellbore is below the bubbling pressure of the pore water, and above the bubbling pressure of the injection water.

- Case DG: If the injection water contains more dissolved gas than the formation water, degassing occurs right at the well during the production period. In this case, the gas filled region does not evolve as a ring; instead, it propagates radially outward from the borehole.

- For Case nDG, gas enters the borehole as a free phase at $t=9.75$ h, leading to a slower pressure decline due to the enhanced total mobility of the produced fluid mixture. Furthermore, the compressibility of the fluid in the borehole increases instantaneously. The same reduction of the pressure decline is also seen in the data. It coincides in time with the first appearance of gas at the surface. Again, the time of this event is not only a function of the gas content in the formation, but also of the amount of gas which is dissolved in the water during the borehole history period.

- After shut-in, the pressure increase reduces the gas saturation in the vicinity of the well by compression and dissolution. For Case nDG, the system turns single-phase near the well and the process previously described reverses. However, the recovery is also influenced by the high compressibility of the gas being trapped in the borehole, leading to a slower pressure reaction compared to the one at the beginning of the pumping period.

4.2.2 MODEL B: FREE GAS

Figure 3 shows a comparison between observed and calculated pressures in the borehole as a function of time for Model B/VG.

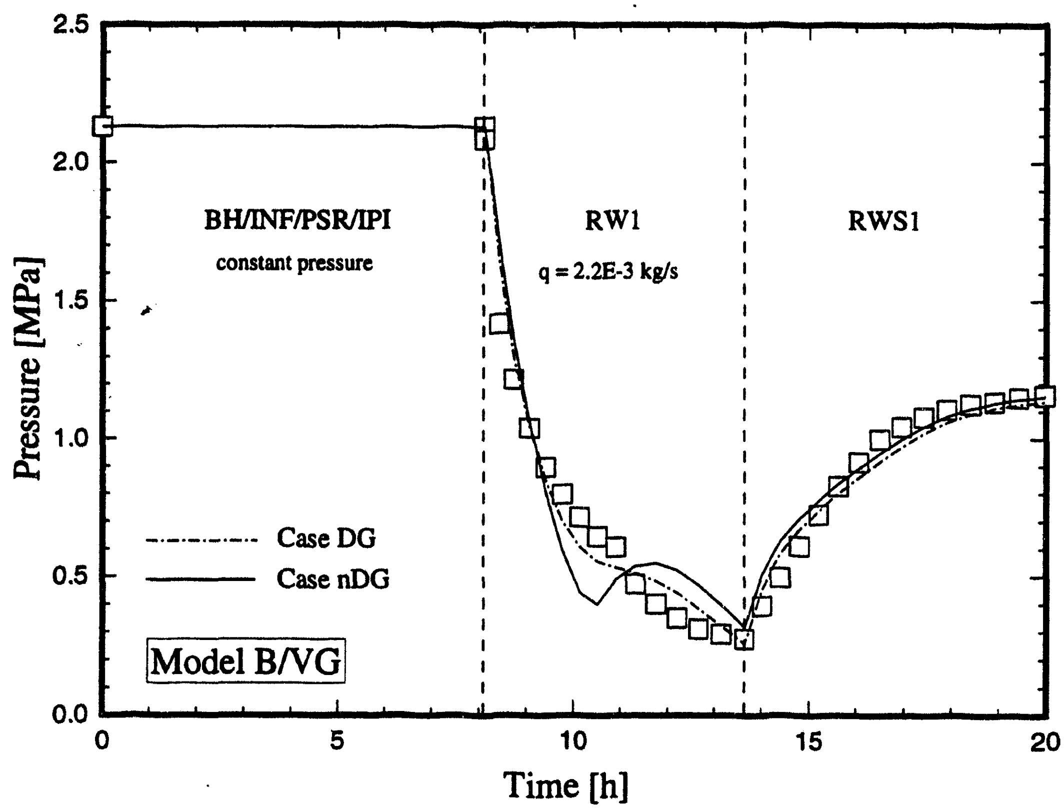

Figure 3: Model B/VG: Comparison between measured and calculated pressure response

The system behavior can be described as follows:

- For Model B, borehole history creates a composite system by displacing the initial mixture of gas and liquid with drilling fluid and water. The injection of water during the initial test sequence creates a liquid saturated zone around the borehole with a radius of about 0.75 m.

- Case nDG: Subsequently, the production of fluid reduces the pressure in the borehole. After 10.5 hours, the gas-liquid front reaches the borehole, resulting in an almost instantaneous increase of the total mobility of the produced fluid mixture, and an increase of wellbore storativity due to the high compressibility of the free gas phase. Consequently, the pressure in the well increases despite continuous pumping at a fixed rate. This temporary effect is not seen in the data, because phase changes occur more slowly and probably along discrete flow channels, whereas in the numerical model, gas enters the borehole at its entire perimeter between two successive time steps.

- Case DG: The dissolved gas in the injection fluid comes out of solution immediately after pressure reduction. Therefore, the formation around the well remains unsaturated, and the effects described in the previous paragraph are somewhat weakened. However, pressure decline is slightly reduced after the gas-liquid front has reached the well. Note that high dissolved gas contents in the injection water during borehole history are not considered very likely [*Küpfer*, personal communication].

- After shut-in, formation gas keeps invading the borehole (unlike the system behavior described for Model A).

4.2.3 GAS PRODUCTION

A phase separator was installed at the surface to measure both gas and liquid flow rates independently. The gas flow rate was strongly fluctuating during the pumping period which may be caused by the coalescing of gas bubbles rising in the borehole. The total amount of gas produced at the wellhead during the RW1 period is given to be 0.270 sm^3 [*QLR*,1993]. This includes gas which is originally dissolved in the water at downhole pressures, and which comes out of solution while being depressurized at the surface. Table 1 summarizes the results of the TOUGH2 simulations for the four models being studied.

For Model A, the maximum amount of free gas available for production is limited by the water volume around the borehole that experiences pressures below the bubbling pressure. The latter is a function of the amount of gas being dissolved and has an upper limit at the ambient pressure prior to pumping. This assumes local equilibrium; the effect of supersaturation is not considered. While the maximum bulk gas mass available for production is relatively easy to determine, the transport of the free gas phase toward the borehole is a complicated mechanism (including phase interferences, capillary forces, flow instabilities, degassing and dissolution, channeling effects, etc.) which may significantly reduce the actual gas production. As outlined in Section 4.2.1, gas may come out of solution in a ring-shaped region at a certain distance from the well. The subsequent transport of the free gas phase toward the borehole thus depends on the relative gas permeability. The gas saturation in the formation remains low, and van Genuchten's characteristic curves have to be modified in order to make the gas mobile for production. In conclusion, **if gas is not extremely mobile** (using the modified van Genuchten model), **the gas observed at the surface cannot be explained by Model A.** Model A tends to underpredict gas flow rates, even though a maximum amount of dissolved gas is assumed. On the other hand, **if a free gas phase is originally present in the formation (Model B), gas relative permeability has to be low in order not to overpredict the gas production rate**. Strong phase interferences are represented by van Genuchten's original model. However, **all four conceptual models match the observed gas volume very well.**

Total Gas Volume at the End of RW1 [sm^3]		
	Case nDG	Case DG
Model A/VGm	0.253	0.258
Model B/VG	0.269	0.260
measured	0.270	

Table 1: Total gas volume produced after RW1 pumping period

4.3 Inverse Problem

In this section, the estimated parameter sets obtained by inverse modeling are presented. Recall that calibration was performed based on the total gas production at the end of the first pumping period RW1, and on 30 pressure data during test periods RW1 and RWS1. The results for Model A are summarized in Table 2, those for Model B in Table 3.

Model A/VGm			
Parameter	initial guess	Case nDG	Case DG
$\log(k\ [m^2])$	-16.00	-15.72 ± 0.05	-15.48 ± 0.04
$\log(c_{bh}\ [Pa^{-1}])$	-7.00	-7.34 ± 0.03	-7.43 ± 0.05
$\log(c_m\ [Pa^{-1}])$	-8.00	-8.48 ± 0.02	-8.50 ± 0.69
p_0 [bar]	15.00	13.97 ± 0.57	11.59 ± 0.52
Test statistic	-	0.5	0.4
Kashiap	-	130.9	111.9

Table 2: Model A/VGm: Parameter sets for Case nDG and DG

Model B/VG			
Parameter	initial guess	Case nDG	Case DG
$\log(k\ [m^2])$	-16.00	-15.80 ± 0.04	-15.65 ± 0.08
$\log(c_{bh}\ [Pa^{-1}])$	-7.00	-7.11 ± 0.05	-7.20 ± 0.05
p_0 [bar]	15.00	11.78 ± 0.50	11.60 ± 0.46
S_{g0} [-]	0.20	0.50 ± 0.08	0.39 ± 0.14
n [-]	3.00	3.33 ± 0.55	3.30 ± 0.48
$1/\alpha$ [bar]	3.00	5.29 ± 0.77	5.73 ± 1.38
Test statistic	-	1.0	0.3
Kashiap	-	156.1	124.0

Table 3: Model B/VG: Parameter sets for Case nDG and DG

The estimates for absolute permeability range from 1.6 to $3.3 \cdot 10^{-16}$ m^2 which can be considered a narrow range. However, these estimates are slightly below the ones obtained from previous investigations.

Borehole compressibility ranges from 3.7 to $7.8 \cdot 10^{-8}$ Pa^{-1}. Note that if gas is dissolved in the borehole fluid, the estimate for c_{bh} is lower for case DG than for Case nDG which is consistent with the fact that part of the total system compressibility can be attributed to the free gas phase which evolves in the borehole due to degassing. An independent estimate (e.g. direct measurement in the field) may greatly reduce model uncertainty since borehole compressibility influences early time behavior and is highly correlated to the formation parameters to be estimated.

For Model A, a compressibility of the pore space is estimated. Even though relatively uncertain, the value of $3 \cdot 10^{-9}$ Pa^{-1} is an order of magnitude larger than water compressibility which may indicate that a free gas phase is actually present in the formation, neglected by Model A but adressed in Model B.

The formation pressure is estimated to be far below hydrostatic conditions. It ranges from 11.59 to 13.97 bar which is equivalent to a freshwater head elevation of 859.4 and 883.7 m a.s.l. These values are much lower than the estimate of about 960 m a.s.l. given by *QLR* [1993] based on the Horner plot analysis of the IPI period. Note that the surface altitude is 958.3 m; their estimate assumes a hydrostatic pressure profile which is in contrast to previous investigations at the Wellenberg site, indicating that the host rock is underpressured.

Two-phase flow parameters are estimated for Model B. The parameter n of van Genuchten's characteristic curves appears in both capillary pressure and relative permeability functions. It is therefore highly correlated to absolute permeability, initial gas saturation, and the air entry pressure $1/\alpha$. The latter is itself cross-correlated to the same parameters which results in a poor estimation accuracy. However, capillary pressures and relative permeability affect the system behavior. The estimates are reasonable for the tight formation encountered here.

Finally, a significant amount of free gas between 39 % and 50 % of the pore volume is estimated. Even though highly uncertain, this estimate confirms that the data can be explained assuming two-phase conditions. Note, that porosity is 1 % throughout the model domain.

The estimate of S_{g0} is negatively correlated to changes in total pore volume available for gas storage.

The standard deviations given in Tables 2 and 3 are too optimistic mainly because it is assumed that the underlying conceptual model is correct. Furthermore, parameters which are considered known in this study may in fact increase the uncertainty of the estimated parameter set due to their correlation with the parameters listed in Table 2 and 3, respectively.

5. SUMMARY AND CONCLUDING REMARKS

The test SB4-VM2/216.7 at the Wellenberg site was analyzed using inverse modeling techniques which aims at estimating model parameters based on discrete observations of the system behavior. Prior to parameter estimation, the available data were reviewed in order to assess their quality and to conceptualize the flow system. The data review can be summarized as follows:

- Pretest activities and the configuration of the test system are important for model conceptualization and for the prescription of initial and boundary conditions. A schematic of the test equipment should be provided to the modeler. The anticipated and measured flow rates and pressures for constant rate and constant pressure tests, respectively, help understanding the test sequence. Observed anomalies, valve manipulations, improper functioning of equipment, etc. have to be reported. System compressibility should be measured in the field prior to testing in order to reduce estimation errors.

- Pressure and flow rate data do not show a consistent picture for the anticipated test sequence. We assumed that the pressure data are more reliable. An average gas and liquid production rate was taken to model pump tests with a prescribed flow rate.

- It is important (and usually very difficult) to make sure that the data observed in the field correspond to the model output. If they are conceptually and numerically different, systematic errors are introduced leading to biased estimates. For example, the gas shown at the surface does not correspond to downhole inflow of gas. They have to be corrected or explicitly modeled (see e.g. *Miller* [1980], *Miller et al.* [1982]) to account for degassing and expansion during depressurization.

The results from inverse modeling can be summarized as follows:

- **The pressure and total gas volume observed at the surface can be explained using either of the two models presented in this study**:
  Model A: The formation is essentially liquid saturated; gas flow at the surface is a result of depressurization which leads to degassing of dissolved gaseous components.
  Model B: Gas is originally present in the formation and therefore produced as a free phase.

- **Model A requires high gas relative permeabilities at low gas saturations.** It also assumes that the maximum amount of gas is dissolved in the liquid phase under ambient pressure and temperature conditions. This may be indicative that in certain regions there actually exists a free gas phase.

- **Model B needs strong phase interferences between gas and liquid in order not to overpredict gas production rates.**

- Even though Kashiap's model identification criteria slightly favors Model A/VGm/DG, none of the four submodels considered in this study performs significantly better than the remaining alternatives. Consequently, **model identification has to be based on external criteria.**

- Values for absolute permeability, wellbore compressibility, and initial pressure were estimated. The absolute permeability is around $2 \cdot 10^{-16}$ m^2 ($2 \cdot 10^{-9}$ m/s). The wellbore storage coefficient is estimated to be $8 \cdot 10^{-9}$ m^3/Pa which indicates a relatively high compliance of the test equipment or the presence of a free gas phase in the borehole. Formation pressure is around 12 bars or 860 m a.s.l. which is considerably below hydrostatic pressure conditions.

- Uncertainties in the models describing relative permeability and capillary pressure **do not allow estimating two-phase flow parameters**. However, using van Genuchten's characteristic curves and realistic values for the pores size distribution and the air entry pressure, **Model B comprises a certain amount of free gas in the formation.**

- Inverse modeling techniques allow identifying key processes and parameters affecting hydraulic tests under two-phase flow conditions. Sufficient data of good quality, a precise description of the test configuration, a good understanding of the system behavior, and a powerful and stable numerical model are necessary for successful estimation of hydrogeologic parameters. The objectives of this study could not be fully met because the test configuration and the interpretation of the flow data was highly uncertain. The lack of necessary information in the Quick Look Report may be due to the fact that the test was not designed for parameter estimation but for water sampling.

Acknowledgment

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Glossary

INF	Packer inflation
IPI	Impuls injection (short flow period with rate measurements)
PSR	Static pressure recovery (shut-in)
RW	Constant rate withdrawal test
RWS	Pressure recovery after constant rate withdrawal (shut-in)

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Appendix A1: TOUGH2 Input File

```
WLB SB4-VM2, Model B, van Genuchten, no dissolved gas in injetiion fluid
ROCKS----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
WELLB    2      2650.         .99 1.000E-15 1.000E-15 1.000E-15       2.1    100000.
  1.000E-07
     1          0.0       0.0        1.0       1.0
     1      0.000E+00 0.990E+00 0.100E+01
BOUND    0      2650.         .01 1.000E-15 1.000E-15 1.000E-15       2.1    100000.
RMARL    0      2650.         .01 1.000E-15 1.000E-15 1.000E-15       2.1      1000.

RPCAP----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
    11             .20       .00
    11      3.000E+00 1.000E+00 5.000E+02
PARAM----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
    12000     20001000001000010004000001000.000E-00 2.334E+00 0.000E+00
                                  -1.
  0.100E+00

   .1500000000000E+07  .1020000000000E+02  .1400000000000E+02
MULTI----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
    2    2    2    6
START----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
MESHMAKER (generates radial mesh Rb=0.079 m)
RZ2D
RADII    1
    2
  0.0780000 0.0790000
LOGAR
   80    3 2.000E+01
LAYER
    1
  5.850E+00

ELEM2 (overwrites grid blocks A1  1 generated by MESHMAKER)
A1   1          WELLB .1000E+50 .9990E-03           .0000E-01           .0000E+00

CONN2

GENER----1----*----2----*----3----*----4----*----5----*----6----*----7----*----8
A1  1RW  1                    4      WATE
  0.0000000E+00 0.2920000E+05 0.4910000E+05 0.1000000E+07
  0.0000000E+00-2.2000000E-03 0.0000000E+00 0.0000000E+00

INCON
A1   1             .99000000E-00
   .2130000000000E+07  .0000000000000E+00  .1400000000000E+02

ENDCY
```

Appendix A2: ITOUGH2 Input File

```
************************************************************************
ITOUGH2 input file for WLB SB4-VM2 (Fi, October 14, 1993)
Two-phase flow conditions
Direct problem on file "sb"
************************************************************************

> PARAMETER

  >> ABSOLUTE PERMEABILITY
     >>> MATERIAL: WELLB RMARL
         >>>> ANNOTATION: PERMEABILITY
         >>>> LOGARITHM
         >>>> INDEX      :   1 2 3
         >>>> RANGE      : -20.0 -10.0
         >>>> WEIGHT     :   0.0
         >>>> PRIOR INFO: -16.00
         <<<<
     <<<


  >> CAPILLARY PRESSURE FUNCTION

     >>> DEFAULT
         >>>> VALUE
         >>>> PARAMETER : 1
         >>>> ANNOTATION: PORE SIZE DIST
         >>>> RANGE      : 1.0 10.0
         >>>> WEIGHT     : 0.0
         >>>> PRIOR INFO: 3.0
         <<<<

     >>> DEFAULT
         >>>> VALUE
         >>>> PARAMETER : 2
         >>>> ANNOTATION: AIR ENTRY PRES.
         >>>> RANGE      : 0.1 20.0
         >>>> WEIGHT     : 0.0
         >>>> PRIOR INFO: 3.0
         <<<<
     <<<


  >> COMPRESSIBILITY
     >>> MATERIAL: WELLB
         >>>> LOGARITHM
         >>>> RANGE      : -20.0 -5.0
         >>>> WEIGHT     :  0.0
         >>>> PRIOR INFO: -7.0
         <<<<
     <<<
```

```
>> INITIAL CONDITION FOR PRIMARY VARIABLE NO.: 1

   >>> MATERIAL: RMARL
       >>>> ANNOTATION: INITIAL PRES.
       >>>> VALUE
       >>>> RANGE     :  5.0 20.0
       >>>> WEIGHT    :  0.0
       >>>> PRIOR     : 12.0
       <<<<
   <<<

>> INITIAL CONDITION FOR PRIMARY VARIABLE NO.: 2
   >>> MATERIAL: RMARL
       >>>> ANNOTATION: INITIAL SG
       >>>> VALUE
       >>>> RANGE     : 10.01 10.9
       >>>> WEIGHT    :  0.0
       >>>> PRIOR     :  10.2
       <<<<
   <<<
 <<


> OBSERVATION

  >> TIMES: 2
     1.0 29195.0
  >> TIMES: 15 LOGARITHMICALLY SPACED
     29205.0 49095.0
  >> TIMES: 15 LOGARITHMICALLY SPACED
     49105.0 71915.0

  >> USER: GAS PRODUCTION
     >>> CONNECTION: A1__1  A1__2
         >>>> DATA
              00000   0.270
              1.0E6   0.270
         >>>> WINDOW             : 49094.0 49096.0
         >>>> STANDARD DEVIATION: 2.0E-02
         <<<<
     <<<

  >> GAS PRESSURE
     >>> ELEMENT: A1__1
         >>>> ANNOTATION: PRES. SB4-VM2
         >>>> FACTOR     : 1.0E+06
         >>>> DATA
               00000       2.13000  pressure in [MPa]
               29200       2.13000  time in [sec]
               29233       1.83242
               29248       1.78123
               29263       1.72841
               .....       .......
```

```
                ......      .......
                201385      4.32370
                202585      4.33330
                203785      4.40000
                204985      4.44520
                206185      4.46930
                207385      4.50900
                208585      4.55860
                209785      4.59030
                210985      4.61580
                212185      2.07438
                213385      2.07237
           >>>> STANDARD DEVIATION: 0.1 [MPa]
           <<<<
       <<<
    <<

> COMPUTATION

    >> CONVERGENCE
       >>> ITERATION: 12
       >>> ignore WARNINGS
       <<<

    >> JACOBIAN
       >>> FACTOR: 0.01
       >>> FORWARD: 8
       <<<

    >> OUTPUT
       >>> HOUR
       <<<
    <<
<
```

Appendix B: Suggestions for Future Test Design and Analysis

As pointed out in this report, the difficulties encountered when interpreting the SB4-VM2/216.7 data stem from different sources. While some of the problems are of a more general nature, others are specific for two-phase flow systems. Problems of the first type include uncertainties from unknown or variable wellbore storage coefficients, uncertainties related to the flow regime, poorly defined initial and boundary conditions, as well as incomplete, ambiguous or erroneous reporting. The means to diminish or resolve these difficulties are the following:

- assure exact, detailed, consistent and self-contained reporting;

- perform pulse tests prior and after testing to determine wellbore storage;

- improve logging system. Pressure buildup tests, for example, can be more accurately interpreted by direct measurement of the bottomhole flow rate rather than the production at the wellhead. Variable wellbore storage coefficients - as seen in test SB4-VM2/216.7 - can then be computed from afterflow measurements and the derivatives of downhole pressures (for details see *Meunier et al.* [1985], and *Merrill et al.*, [1974]);

- identify key parameters to be determined and design test accordingly.

The analysis of test data obtained under two-phase flow conditions is subject to additional pitfalls. One of the more fundamental difficulties is the non-linearity inherent to two-phase flow which restricts the analysis to cases which exhibit well-defined, relatively simple conditions. Standard two-phase interpretation techniques used in the gas and oil industry or in geothermal applications assume that there is either no or a sharp saturation front. Furthermore, no pressure gradients in the gas phase are allowed which prevents gas to flow and assures constant mobility and specific storage ratios, etc. The non-linearity problem can partly be accounted for by using numerical simulators, such as ITOUGH2.

In addition, the inverse problem is usually non-unique which requires knowledge of some key parameters in order to be able to determine other parameters. This is reflected in a statement by *Miller et al.* [1982]: "*Absolute permeability and the in-place [...] saturation around the wellbore during the test can be obtained if the relative permeabilities are known as a function of saturation, or, alternatively, the relative permeability curves can be determined if the absolute permeability and in-place saturation are known*". Consequently, it has to be decided a priori which parameters can be determined by other means than well testing, and which parameters are to be estimated by inverse modeling.

The determination of gas related parameters is further complicated by the fact that the host rock of interest has a very low permeability and a low porosity. The literature on two-phase flow testing primarily deals with gas and oil reservoirs (see for example *Merrill et al.* [1974], *Meunier et al.* [1985], *Olarewaju and Lee* [1987]) or geothermal fields (see for example *Horne and Satman* [1980], *Miller et al.* [1982], *Grant et al.* [1982]) where a large amount of gas or vapor is present, respectively.

The purpose of the following suggestions is to initiate a discussion about the design of a welltest which allows the determination of some model parameters in a low porosity, low permeability two-phase flow environment. They should, however, not be applied in the field without a careful review of each aspect of the proposed test sequence.

- in general, determine as many parameters as possible independently, i.e. by means other than well testing (e.g. porosity, wellbore storage, etc.);

- measure retention data (capillary pressure vs. saturation) from core samples. Fit multimodal retention model and predict relative permeabilities according to the procedure proposed by *Durner* [1994];

- pump to remove drilling fluid around well; obtain water samples under ambient conditions for chemical analysis; determine dissolved gas content; look for evidence of free gas in the formation; stop pumping; allow for pressure stabilization and saturation redistribution;

- perform constant flow water injection test (preferably deaired water), creating an composite system with an inner, liquid saturated zone; analyze pressure buildup and shut-in recovery period (e.g. by standard evaluation methods or using ITOUGH2); measure downhole pressures and flow rates and account for afterflow; determine absolute permeability of inner zone; estimate mobility and specific storage ratio between inner and outer zone (if long enough recovery period available) ;

- perform constant flow pumping test at the same rate; check for consistency with injection test during the initial test period under single phase flow conditions; stop after about 75% of the injected fluid is withdrawn to avoid two-phase flow in the wellbore; analyze pressure buildup after shut-in; fix the absolute permeability and matrix compressibility at their values determined during the previous test events (if consistent); estimate gas saturation of the outer zone;

- this test sequence can be followed by a gas injection period or by a continuation of pumping.

The basic idea of the test sequence outlined above is to create well-defined, single phase conditions around the borehole by first withdrawing drilling fluid followed by an injection of water. Degassing is suppressed by using injection water of low gas content, avoiding two-phase flow effects in the well during the subsequent pumping period. Adding a pumping period after the injection test allows for a more reliable determination of the inner zone, intrinsic parameters (absolute permeability and saturated sorage coefficient of skin zone and formation). Furthermore, it pulls the saturation discontinuity back toward the borehole, enhancing the chance to determine two-phase flow parameters (especially gas saturation) of the outer zone during the second recovery period.

The test design proposed herein should be assessed and further refined using numerical simulations. This is, however, beyond the scope of this report. Experiences from the gas and oil industry as well as from geothermal and gas storage applications should be carefully reviewed.

Appendix C: Quick Look Report, faxed September 30, 1993

T E L E F A X

From: Olivier Jaquet
Colenco
Mellingerstrasse 207
5405 Baden
Switzerland

Fx: 0041 56 83 73 57

Date: 30.09.1993

To: Mr. Stefan Finsterle
Lawrence Berkeley Laboratory
Earth Sciences Division
One Cyclotron Road
Mail Stop 50 E
Berkeley, CA 94720

Fax No.: 001 510 486 56 86

Transmitted: 14 page(s) (incl. cover sheet)

Dear Stefan,

After many discussions with Karsten, Srikanta, Pascal and Rainer, it was decided on the base of the "good" quality of the data available for SB4_VM2 to get your help. The aims are still estimating two-phase parameters but also investigating various conceptual models for this test. The conceptual models you will use will differ from the one(s) I am applying. We will then work in parallell. Then, this should give us a more plausible range for the estimated two-phase parameters.

I have mailed you the file of the pressure, the gas and water flow rates, the parameters used are included together with a copy of the main part of the Quick look report of Golder.

And as usual a few questions, can you use in ITOUGH2 different data sets with various time scales (e.g. pressure data between t1 and t3 and water rates between t1 and t2 where t2 < t3) ? What permeability value, when an inner zone is present, are you using for the well ? Is it correct to use the same value as the inner zone ? What relative-k and capillary curves are you generally using for the well, same type as for the marl ?

And finally, if you find any strange parameter value(s) in the table below, just let me know, it might reduce the uncertainty. You might need to get in contact with Pascal for the defnition of the expected reporting modalities. And of course, if you have further questions regarding details of the test, I will at your disposal.

Thank you in advance for your help and good luck for the inversing.

Sincerely, Olivier

TABLE I: MODEL PARAMETERS (best guesses)

PARAMETER	WELLB	DMARL	STD	RMARL	STD
permeability [m^2]	$9\cdot10^{-19}$???	$9\cdot10^{-15}$	0.5	$6\cdot10^{-16}$	0.5
gas saturation	0.00	0.00	???	0.54???	0.1???
initial pressure [Pa]	$1.646\cdot10^{+5}$	$1.646\cdot10^{+6}$	$2.45\cdot10^{+5}$	$1.646\cdot10^{+6}$	$2.45\cdot10^{+5}$
compressibility [m^2]	$2\cdot10^{-9}$	$1\cdot10^{-10}$	0.25	$1\cdot10^{-10}$	0.25
porosity	0.99	0.01	???	0.01	???
S_{rl}	0.0	0.25	fixed	0.25	fixed
S_{rg}	0.0	0.20	0.05	0.20	0.05
Air entry pressure [Pa]	$1\cdot10^{+5}$	$1\cdot115^{+6}$	0.25	$2.885\cdot10^{+5}$	0.25
lambda	2	2	0.5	2	0.5
Maximum pressure [Pa]	$1\cdot10^{+7}$	$1\cdot10^{+7}$	fixed	$1\cdot10^{+7}$	fixed

Comments:

permeability: Golder and Colenco (reviewed) estimates from single phase analysis

gas saturation: estimate from volumes calculations based on the measurements

initial pressure: Colenco estimate from welltest analysis

compressibility: laboratory measurements on cores

porosity: a priori guess

residual liquid: a priori guess

residual gas: a priori guess

air entry pressure: estimated by regression from the permeability

lambda:	literature value

<u>Other parameters:</u>

- relative permeability curves: Brooks-Corey (IRP=10), ev. Grant
- capillary curve: Brooks-Corey (ICP=10)

- module EOS 3 (air)

- system thickness	= 5.85 m	
- wellbore radius	= 0.079 m	
- altitude surface	= 958.3 m	
- altitude test	= 741.3 m	
- radius of inner zone	= 0.3 m	
- temperature	= 14 C	
- wellbore volumes	RW1	= 0.146 m3
	RWS1	= 0.134 m3
	RW2	= 0.146 m3
- time scales	RW1	29'226 - 49'110 s
	RWS1	49'110 - 71'922 s
	RW2	71'922 - 184'020 s

ITA

QUICK LOOK REPORT SB4-VM-2

z = 958.3

WELL	:Wellenberg SB4	TOTAL HOLE DEPTH*	:	219.60	m
DATE	: 17-19.06.1990	LOWER SEAL	:	213.75	m
TOP	: 213.75 m	BTTM	:	219.60	m
INTERVAL LENGTH	: 5.85 m	MIDPOINT OF INTERVAL	:	216.7	m
r_w	: 0.079m	r_u (2.875")	:	0.036	m
p_2-DEPTH	: 210.03 m	ANNULUS DEPTH	:	-0.8**	m

*) All depths are apparent depths
**) Calculated from P_3-reading after setting the packer.

.01

SINGLE PACKER TEST

PRELIMINARY INFORMATION

EST. STATIC PRESSURE	: 2044 kPa at P_2	(from SB4-VM1/??)
POROSITY	: 0.01	(estimated)
MUD DENSITY	: 1045 kgm^{-3}	(16.06.90)
FLUID VISCOSITY	: 1.15 10^{-3} Pas	(assumed for P, T water)
FLUID COMPRESSIBILITY	: 4.42 10^{-10} Pa^{-1}	(assumed for P, T water)
TOTAL COMPRESSIBILITY	: 4.42 10^{-10} Pa^{-1}	(assumed $c_t = c_w$)

BOREHOLE HISTORY : Intersect top of zone on 16.06.90 at 14:00, bottom on 16.06.90 at 18:55, mud pressure: 3 - 4 bar (head)

DRILLING : Mud losses averaged 0.2 m^3/h when drilling through the interval

GEOLOGY : Valanginian Marl with some limestone filled fractures

GEOPHYSICS : No logging data available. Borehole inclination assumed to be 15^0.

TESTING ENGINEERS:

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SUMMARY OF TEST EVENTS/RESULTS VM-2

second version

4"

EVENT	INF	PSR[2]	IPI[3]	RW1	RWS1
EL.TIME, [min]	8.0	37.3	441.8	331.4	380.2
T_i/T_f, [°C]	14.6/14.7	14.7/14.5	14.5/14.2	14.2/14.0	14.0/13.9
P_{1i}/P_{1f} [bar]	21.79/21.82	21.82/21.83	22.67/21.15	21.18/2.56	2.56/11.48
P_{2i}/P_{2f} [bar]	21.91/21.97	21.97/21.99	22.82/21.32	21.32/2.72	2.72/11.62
P_{3i}/P_{3f} [bar]	21.89/21.90	21.90/21.92	21.91/21.84	21.72/21.72	21.72/21.61
P_{sep} [bar]	-	-	-	3.0	3.0
$T_{sep}(W)$ [°C]	-	-	-	-	-
$T_{sep}(G)$ [°C]	-	-	-	-	-
q_t [m^3s^{-1}]	-	-	-	-	-
q_w [m^3s^{-1}]	-	-	-3.0E-04	2.2E-06	0.0
q_g [m^3s^{-1}]	-	-	0.0	1.3E-05	0.0
Q_w [m^3]	-	-	-9.0E-03	3.7E-02[6]	0.0
Q_g [sm^3]	-	-	0.0	2.7E-01	0.0
K_w [ms^{-1}]	-	-	(8.9E-08)[3]	7.4E-10	-
k_w [m^2]	-	-	(1.0E-14)[3]	9.0E-17	-
T_w [m^2s^{-1}]	-	-	(5.2E-07)[3]	4.3E-09	-
P_s at P_2 [bar]	-	-	21.32[4]	-	-
Head(P_2) [m asl]	-	N.D.	962.6[1]	-	-
S [-]	-	-	2.5E-07	2.5E-07	-
S_s [-]	-	-	4.3E-08	4.3E-08	-
C [m^3/Pa]	-	-	6.5E-08[5]	2.0E-09	-
C_D [-]	-	-	8.4E+04	1.9E+03	-
s [-]	-	-	-0.9	-3.0	-
LAMBDA [-]	-	-	-	-	-
OMEGA [-]	-	-	-	-	-
FIGURE #	1,3	1,2,3	4-6/1-3	7/1-3	8/1-3
TEMPERATURE EFF.	-	NO	NO	NO	NO
BH. HIST. EFF.	-	NO	NO	NO	NO
BOUNDARY EFF.	-	NO	NO	NO	NO
ANOMALY	-	NO	NO	NO	NO

EVENT	RW2[2]	RWS2			
EL.TIME, [min]	1868.3	449.7			
T_i/T_f, [°C]	14.0/13.7	13.7/13.8			
P_{1i}/P_{1f} [bar]	11.45/1.58	1.58/4.47			
P_{2i}/P_{2f} [bar]	11.62/1.72	1.72/4.62			
P_{3i}/P_{3f} [bar]	21.61/21.08	21.08/21.03			
P_{sep} [bar]	3.0	3.0			
$T_{sep}(W)$ [°C]	-	-			
$T_{sep}(G)$ [°C]	-	-			
q_t [m^3s^{-1}]	-	-			
q_w [m^3s^{-1}]	5.0E-07	0.0	Not affected ?		
q_g [m^3s^{-1}]	1.7E-05	0.0			
Q_w [m^3]	5.6E-02[5]	0.0			
Q_g [sm^3]	1.9	0.0			
K_w [ms^{-1}]	3.1E-09	5.9E-09			
k_w [m^2]	3.6E-16	6.9E-16			
T_w [m^2s^{-1}]	1.8E-08	3.4E-08			
P_s at P_2 [bar]	-	-			
Head(P_2) [m asl]	-	-			
s [-]	2.5E-07	2.5E-07			
S_s [-]	4.3E-08	4.3E-08			
C [m^3/Pa]	9.0E-10	1.9E-08			
C_D [-]	5.9E-02	1.9E-04			
s [-]	5.8	0.8			
LAMBDA [-]	-	-			
OMEGA [-]	-	-			
FIGURE #	9/1-3	10/1-3			
TEMPERATURE EFF.	NO	NO			
BH. HIST. EFF.	NO	NO			
BOUNDARY EFF.	NO	NO			
ANOMALY	NO	NO			

[redacted]

1) Fresh water equivalent for (rho) = 1000 kgm^{-3}, g = 9.81 ms^{-2}, corrected for borehole inclination (15°), see also comments
2) At the beginning of the PSR period shut-in tool was not closed properly when filling up the system.
3) Pressure impulse lasted 30 s with an injection rate of 15 l/min. This resulted in pressure increase of 83 kPa. The recovery period resulted in pressure falling far below the end value of the PSR period and consequently made the analysis ambiguous.
4) Not stabilized, Horner extrapolation resulted in P_0 value of 2107 kPa (960.0 m asl.).
5) C calculated from injection data is 9.0E-08 m^3/Pa. The system compressibility is estimated to be as high as 1.3E-07 Pa^{-1}. ?
6) The total water volume produced at the surface is about 0.11 m^3 since due to the storage of the system above the shut-in tool water was still flowing during the RW81 period.
(recovery)

gas rate : Brauhlnct

[redacted]

The main objective of the interval test SB4-VM2/216.7 was water sampling. Therefore, no attention was paid to maintaining the inner boundary condition of constant rate ~~nor~~ or pressure.

The static pressure recovery period was very short and resulted in an equivalent hydraulic head of 962.6 m asl. The Horner extrapolation of the IPI period yielded 960.0 m asl. This difference is most probably caused by the borehole pressure history.

The analysis of the diagnostic impulse test was difficult because the formation pressure was not stabilized prior to injection. High compressibility of the system suggested the presence of gas in the test interval. This was confirmed by the type of response of the RWS periods. The presence of gas, but first of all the test sequence planned only towards the maximizing the production rate made the pressure data difficult for analysis (the log-log plots are self-explaining). The changing (not determined) saturation conditions at the borehole face allow only rough estimation of water effective permeability to be within 0.7 to 6.0E-09 m/s. The estimation of the skin factor is very ambiguous for the same reasons.

?

It is interesting to note that the amount of gas produced proved that there was a free gas in the test interval.

higher compressibility of interval

air lift

range$_{skin}$ = 0.01 – 1 m

b. guess$_{skin}$ = 0.3 m . (1) → $\boxed{\text{see OBS}}$

0.1 m (2)

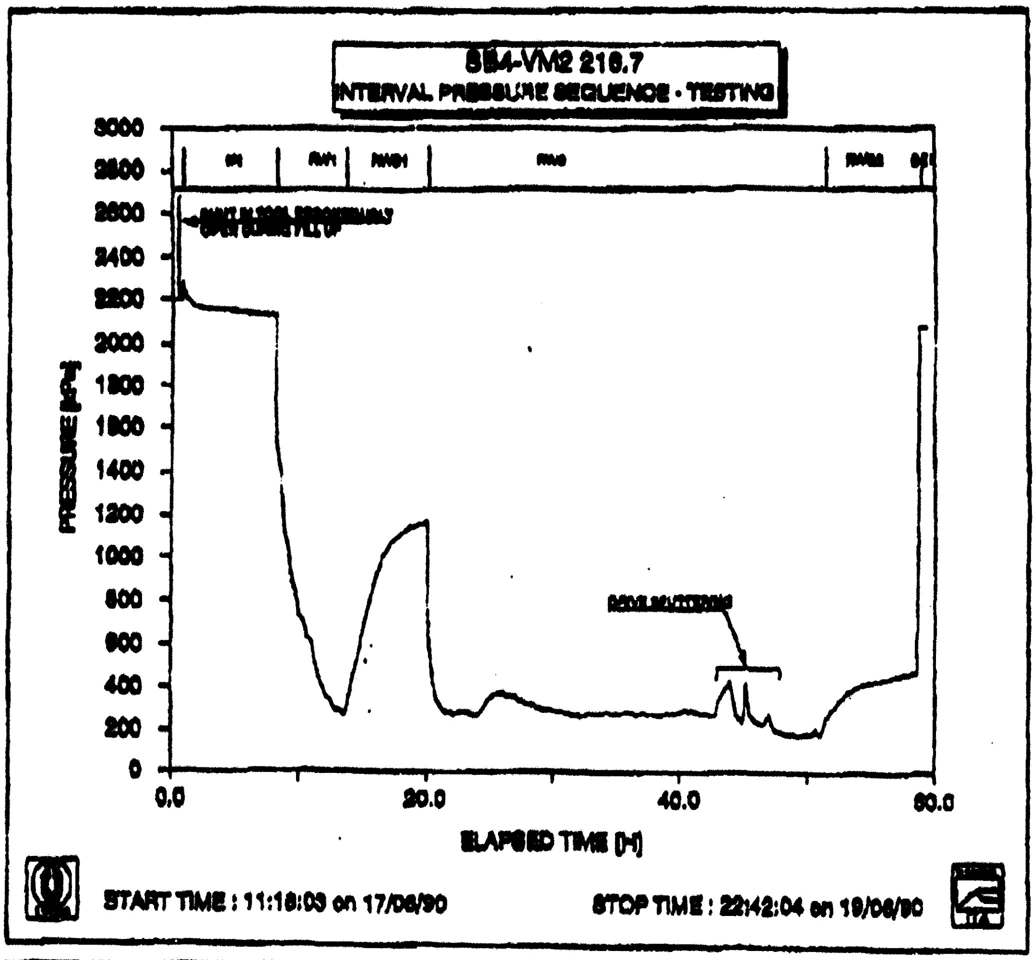

FIG.1b SB4 VM2/216.7 INTERVAL PRESSURE SEQUENCE - TESTING

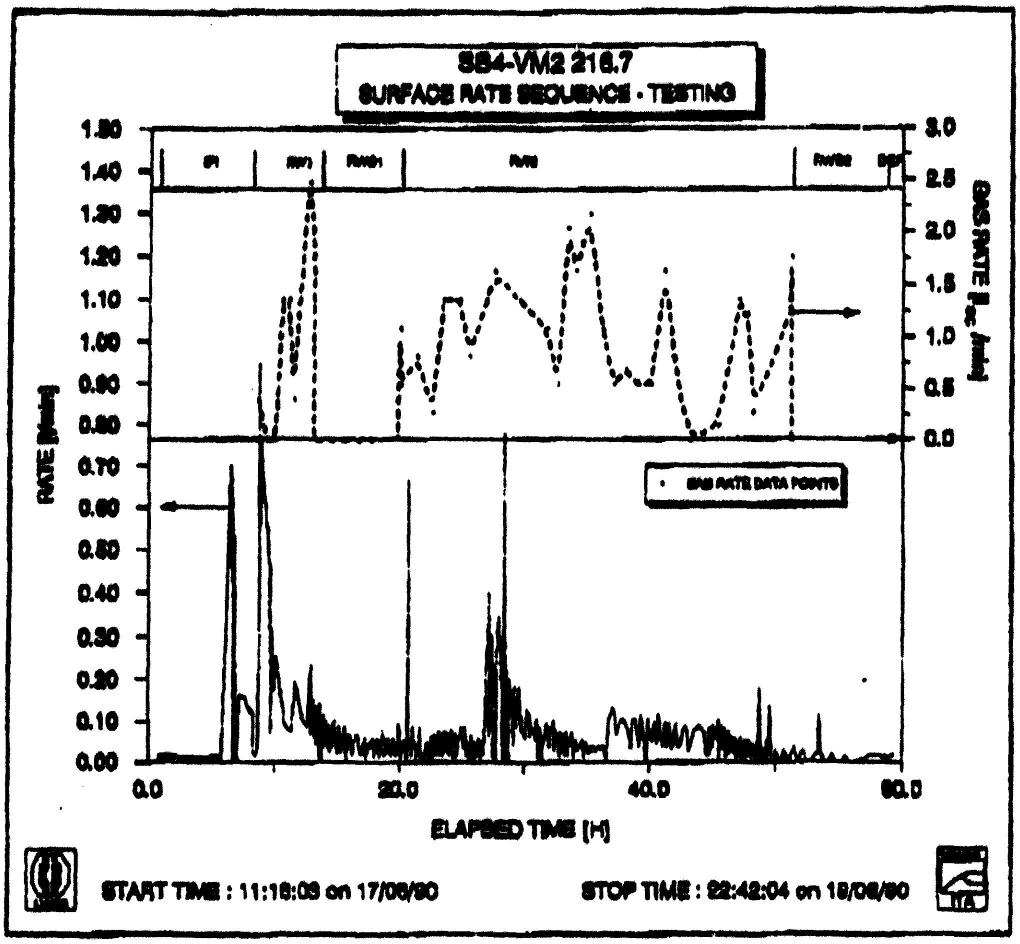

FIG.2 SB4 VM2/216.7 SURFACE RATE SEQUENCE - TESTING

DATE
FILMED
6/ 1 /94

END