Testing of Deep Hot-Water Wells - Best Practice

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ABSTRACT

1. Subtraction of ESP- from deep gauge-pressures result in correction curve, water salinity and early detection of possible salt dropout.
2. Correction curve can be used in next wells.
3. Interference testing during test of second well gives valuable information about future doublet performance for little extra effort and can prevent subsurface problems.
4. System compressibility is calculated from ratio of atmospheric pressure variation and its effect on the reservoir pressure.
5. A simulation program of an interference test in a semi-infinite channel has been created and is available on request.

1. INTRODUCTION

The author (Ir physics Delft) worked, after a career as reservoir engineer with Shell, as an independent well testing expert all over the world. In 2011 he was asked by Panterra to look at the test of a deep hot-water well. It was obvious that the main analysis problem was the cooling of the water column between pressure gauge and reservoir during the pressure build-up (BU), making this BU unanalyzable. Since then, the author has designed and analyzed tests in 20 wells in 10 projects in the west of The Netherlands. He also contributed to the improvement of the "Richtlijnen voor uitvoering en interpretatie van een puttest" by TNO. With this paper he wants to ensure, at the end of his testing career, that his experiences with these well tests are available for future well-testing engineers. In spite of the request to use SI units, all figures are in the practical units as used by the hot-water industry in The Netherlands: m, m^3, hr, cP, mD and bar^{-1}. Conversion factors can be found in Appendix A.

2. WELLTEST DESIGN

The duration of the test sequence depends on reservoir quality and test objectives. If the presence of flow barriers in a low-permeability reservoir is important, the test has to last longer than in a high-permeability reservoir with a good seismic definition of the fault pattern.

In nearly all deep hot-water wells, the salt-saturated water has a static water level some 50 – 100 m below ground level and is pumped up by an Electrical Submersible Pump (ESP) suspended from a 500 – 800 m long tubing. The flowing water level should always remain at least 100 m above the pump intake. Better is a minimum ESP pressure of 15 bar, as no annulus air may reach the pump intake.

Another reason to limit the maximum drawdown (static minus flowing pressure) is the possibility that a separate reservoir layer is not present in the other well of the doublet. That layer will not be re-pressurised by the injector and thus obtain a constant reservoir pressure that is the average drawdown below the initial reservoir pressure. The same is valid for a too high injection pressure in the injector. Only when the doublet is stopped for maintenance, this separate layer can return to its original pressure. The maximum drawdown in all 20 well tests was 50 bar.

The well should be cleaned at an increasing motor power, checking at surface for a good rate response. If more power results in hardly more flow it may indicate sand influx. Continue at maximum flow rate (ESP pressure $\geq$ 15 bar) until the THP shows the transient pressure decline, meaning that the well is clean. Reduce power for two periods of about 2 hrs at subsequently 30% and 60% of maximum rate. If a deep water sample is required, it should be taken at the end of the second period. Finally flow at 90% for 4 – 8 hrs. This maximum rate should last so long to ensure a good clean-up of the production interval and to "look" far enough into the reservoir. This period can also be analysed if no deep gauge data are available (flowing water column at a constant high temperature). The total water production can of course not exceed the available storage capacity, possibly requiring a lower/shorter maximum rate.

The well should remain untouched for the subsequent pressure build-up period (BU) of 12 – 24 hours. This BU is required for a good analysis as there is no noise from the motor, no flow turbulence and no influence of a (changing) skin. The length of this BU should be no more than 3 times the teff = Np/Ql (The effective time equals the cumulative production divided by the final flowrate). The longer the BU, the further the test "looks" into the reservoir. For hot salty water this distance d equals (d in m, k in m^2 and t in sec):

$$d = 3000 * \sqrt{(k * t)} \qquad [1]$$

(With d in m, k in mD and t in hours, the constant is 6).

If the test objective is only to obtain the reservoir transmissibility (k.h/mu) and well damage (skin S), the test can be short, e.g. 8 hrs total flow and 8 hrs BU. The

ESP pressures can be used, if there is sufficient data available from a nearby well to correct the BU for the cooling of the water column between ESP and top reservoir. Otherwise, an accurate deep gauge should be lowered on wireline as deep as possible, but not deeper than 20 m above top reservoir. See also next chapter.

The ESP and the deep gauge pressure/temperature sensors should be set to sample not more often than 10 times per minute. The analysis plots the data on a logarithmic time scale. The early 3-8 minutes are non-analysable wellbore effects. Many engineers think the more data, the better, but it only costs more time to handle (too) large files. Also, pressure sensors have been observed to loose accuracy when sampling every second.

Just before the test of the second well of a doublet, a cheap but accurate pressure sensor should be installed in the first tested well some 20 to 30 m below the static water level, with this well kept closed-in and untouched for at least two (in poor reservoirs three) weeks after the test of the second well. This sensor will record the interference between the two wells, important for the evaluation/prediction of the future project performance. If there is no sign of any interference, the project can of course not proceed without drilling another well that has sufficient communication with one of the drilled wells. As an interference test is more a material-balance test than a radial flow test, the (minimum) reservoir area of the project can be deduced by matching a simple two well analytical model in a bounded reservoir, see Appendix B. Such sensors are available at Fugro. In order to record the pressure for a month and in view of the limited data storage capacity of the Fugro meters, the sampling frequency should not exceed 1 data point per 3 to 5 minutes, which frequency is more than adequate for an accurate analysis.

In the first well in an area, a deep gauge on wireline should always be used. The subsequent correction for the ESP pressures can eventually be used for next wells in the same reservoir, see next chapter.

3. COOLING WATER COLUMN

The build-up pressures of the deep gauge (bhg) should first be corrected for the few (3 – 6) pressure steps, caused by upward gauge movements, due to wireline shrinkage: the cooling wire will pull the gauge upwards until this pull is stronger than the static friction of the gauge with the pipe wall. The gauge jumps then 10 – 40 cm upwards.

The exact time and magnitude of these corrections can conveniently be determined using a simple (open-source) plotting program "Gnuplot". This program allows the subsequent fitting and subtraction of a function through the pressure points, see the blue points in Figure-1. An example of the Gnuplot-command file, used in this Figure, can be found in Appendix-C.

The exact times and size of the jumps can be read from this figure. Each jump should be added to the gauge pressure after its corresponding time, resulting in the correct, smooth curve (red points), which should then be used in the test analysis. The green points and the purple line are the original and corrected pressures on the right-hand scale. For this correction the author uses his own Fortran filtering program, using a moving-average reduction of data points. Excel may be another option. For poor reservoirs (k.h < 10 D.m) with a large drawdown, this correction is not really required. But in good reservoirs it can change the slope of the BU and thus the analysis results.

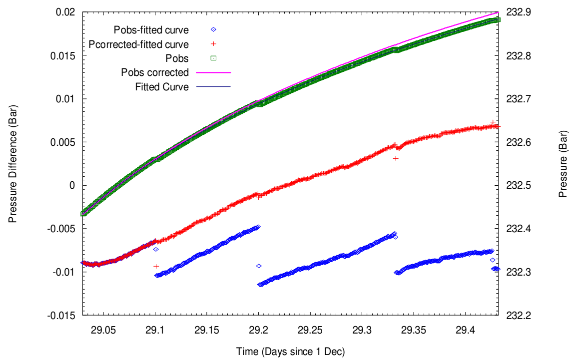

Figure-1 Deep-gauge movements

If pressures are available from both the ESP and a deeper accurate pressure gauge, the pressure difference between both gauges should be divided by their (true vertical) depth difference and plotted versus the ESP Temperature (blue points), with the deep gauge Temp. plotted on the right-hand scale. Figure-02 shows this plot for the Rotliegendes, one of the most extensive deep reservoirs in the north of The Netherlands. The red line through the blue points is a quadratic equation fitted through these points, which can be used in the second well of the doublet (and other nearby wells in the same reservoir) to correct the ESP pressures to datum depth by multiplying with the vertical depth difference L between ESP and top reservoir:

$$f(T) = C *\{1087.5+0.468*dT-0.00231*dT^2\}$$

$$Dp = L * f(T), \qquad [2]$$

with dT=(Tmax-T) and C=9.80665E-05 (kg/m3 into bar/m).

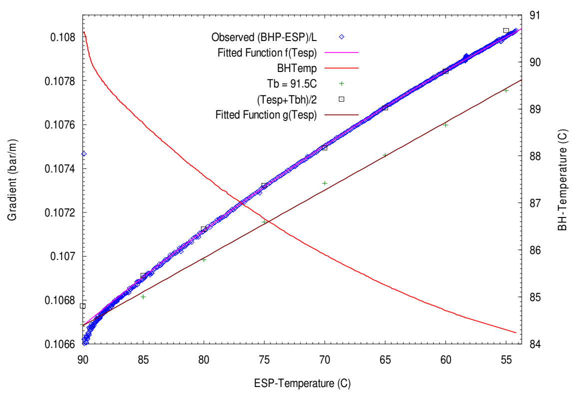

Figure-2 Water gradient increase during BU

Note the deviation from the fitted curve at the start of the BU. This is caused by wellbore effects: by water-hammer caused by the kinetic energy of the flowing water, by an ESP temperature increase caused by the hot motor and by some backflow after the water-hammer. If no correction curve or deep gauge is available, the correction curve can be constructed from the water salinity measured from a sample, using Figure-15. The red points in Figure-02 have been read from Figure-15 for the average Tesp and Tbhg and fall indeed on the measured curve, proving the validity of Figure-15. The green points used an average T of (91.5 + Tesp)/2, with a purple straight line fitted through these points. This linear function should be used to extrapolate observed ESP pressures to top reservoir depth; the red curve corrects only down to the deep gauge depth. This line is flatter than the red curve because the BH-gauge temperature (190 m above top reservoir) dropped about 7 C, while extrapolation to top reservoir has a fixed temperature at bottom. The error between both corrections for an extrapolation over 1700 m is about 0.3 bar at the end of the BU. In wells with a deeper downhole gauge this error will be smaller. From the density (1087.5 kg/m^3 @ Tmax), the in-situ water salinity can be obtained, probably with a better resolution than from a water sample, using the curves from Figure-15 in Appendix D. See also Reference C: Long and Chierici, 1959.

From the salinity, the reservoir water viscosity and compressibility can be read from standard graphs. On average a water viscosity of 0.48 cP has been used in the analyses. The water compressibility is more uncertain, as all deep water contains dissolved methane. From interference tests a total reservoir compressibility between 3 and 6E-7 bar^{-1} (4-9E-6 psi^{-1}) was found to give the best model matches.

But the most compelling reason to construct the plot of Figure-01 (not necessary for the analysis, if a deep enough gauge has been used) is presented in Figure-03, showing the water density vs. Tesp for a well in a different reservoir.

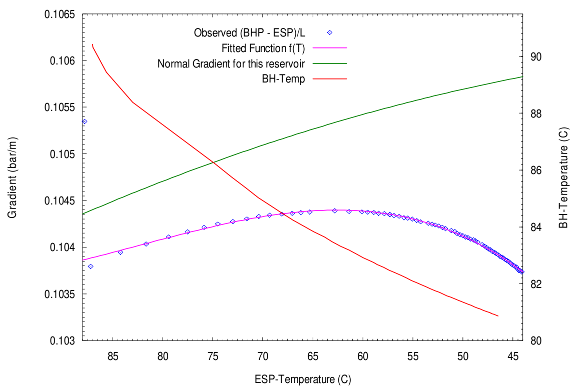

Figure-3 Salt deposition in well by cooling

The green curve was expected, but the late pressure difference between both gauges showed a continuous decline in density (and thus in salinity) with a decreasing tubing temperature. This can only happen if salt precipitates on the tubing wall. There should then also be a salt layer on the bottom of the cold water storage! It is obvious that such a well cannot be used as water producer, as this salt should block the heat exchanger rapidly. If the other well of the doublet shows a normal constant salinity, and the interference test indicates a good communication between both wells, this well can be used as injector. The different water comes apparently from a separate local sand layer, not present in the other well.

In order to avoid the (small) possibility of such a freak geological feature to ruin a costly hot-water project, it is advised to use at least two pressure gauges at a vertical distance of several hundred meter, and to check always the contents of the surface water storage facility for any deposit on the bottom.

The green line is the expected density; the blue points the observed density (the purple line is a third-power equation fitted through these points).

4. ANALYSIS OF TEST DATA

In reference B, Dake 1978, the equations and practices used in well-test analysis can be found.

Reference D, Long & Chierici 1961, provide the water compressibility. The hot brine viscosity may vary between 0.4 cP @ 100 C and 0.6 cP @ 70 C, according to internal Shell curves.

The analysis of the individual well test is normally carried out by matching the whole test pressure/rate history with an analytical well model, with emphasis on the build-up (BU) data, using available Petrophysical (net layer thickness, porosity) and Seismic information (faults that could be sealing flow-barriers). The common well model is a fully penetrating vertical well in a rectangular bounded reservoir. Some or all four boundaries may be outside the distance of investigation of the test. But often one or two flow barriers can be observed on the derivative of the BU. These flow barriers are mostly large faults, but can also be caused by partial faults or an unconformity (end of reservoir against newer layers). Note that a partial fault can be matched with a sealing fault in the model, if the test is not long enough to prove that wrong.

If there is no deep gauge nor a correction equation to correct the negative BU (caused by the cooling water column below the ESP), the final flowing period can be analyzed, although less accurate and with less detail than the analysis of a corrected BU.

A recurrent feature in all analyses has been a systematic mismatch between the radial permeability from the well tests and the linear permeability from the interference test between the two doublet wells. The most likely explanation is the probable presence of small, sub-seismic, faults parallel with the main faults that are seen as the channel boundaries of the doublet area. The permeability parallel with these faults is the undisturbed sand permeability. The permeability at a right angle is reduced by the flow resistance of the small parallel faults, causing permeability anisotropy. In the deep underground of the west of The Netherlands, the geological stress regime seems to create mayor faults (and thus also minor faults in between) in a south-east to north-west direction.

The use of a multi-layer model was not required in the hot-water well tests analyzed by the author, as no “dual-permeability” has been observed. Only two wells showed a clear “partially-penetrating” effect (only part of the reservoir open to flow), which could be matched with a partially-penetrating-wellbore model (but of course also with a two-layer model), Figure 4.

The PP-model is the purple, matching, line. As contrast also a fully-penetrating well response derivative is plotted as the black line.

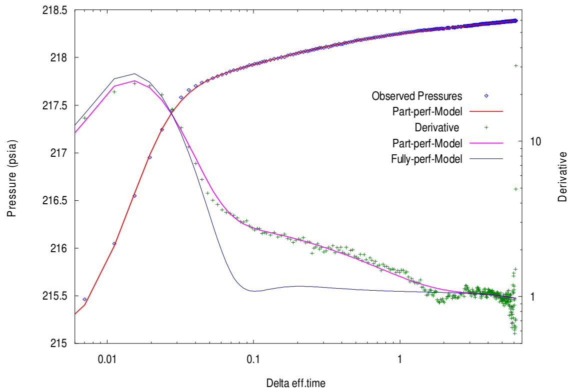

Figure-4 Partially Penetrating Well

The analyzing engineer should resist to use a more complex model over a simpler one, as that would suggest more information than available, as long as both models give the same match quality.
For engineers who do not have an analytical well model available, Appendix E presents the Horner method to calculate the wellbore skin and reservoir permeability.

Figure 5 presents the pressures from a test with a rather good match of a well in an infinite flow channel of two parallel faults, showing all characteristics of deep hot-water well tests: After the cleanup, the well was tested with three flowrates (The short build-ups in between are not advised by TNO anymore).

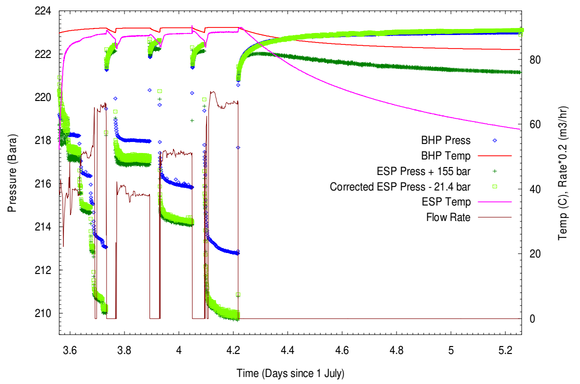

Figure-5 Well Test Data

Note the severe influence of the cooling water column below the ESP on the BU, making the (dark green) ESP pressures non-analyzable without correction for this cooling column. The ESP pressure at the highest flow period is 2.8 bar lower than the (blue) deep gauge pressure, which is thus the friction at 330 m3/hr in the 1685 m of 9 5/8 inch casing between the deep gauge and the ESP. The (light green) corrected ESP pressures are covering the deep gauge pressures during the (corrected) BU, as expected. The low gauge sampling rate in this test of 2 points per minute had apparently no effect on the analysis results.

The input parameters for an analytical well model are the wellbore radius rw, the water viscosity muw, the water and pore compressibility. The volume of the recorded water at surface can be assumed to be the same as that in the reservoir, Bw of 1.
The water viscosity and compressibility depend somewhat on the salinity and temperature, but can on average be set at respectively 0.48 cP and 2E-7 bar^{-1}.

The rw is normally half the bit diameter, corrected for the angle α (90 for vertical) through the reservoir:

$$Rweff = Rw*\sqrt{\{(1+1/\cos\alpha^2)/2\}} \qquad [3]$$

The total system compressibility varies between 3E-7 and 7E-7 bar^{-1}. It can be calculated from the effect of the atmospheric pressure on the reservoir pressure, normally observed during an interference test or a long BU. See next chapter.

Figure 6 shows the Horner plot (dark blue dots) with its derivative (light blue dots) for the final build-up of the deep gauge data, which have been corrected for wireline movement, for the atmospheric pressure variation effect, and for the cooling of the 191 m between the deep gauge and top reservoir, using the correction function determined by subtraction of the ESP pressures from the bhg-pressures. All three corrections did change the model match somewhat.

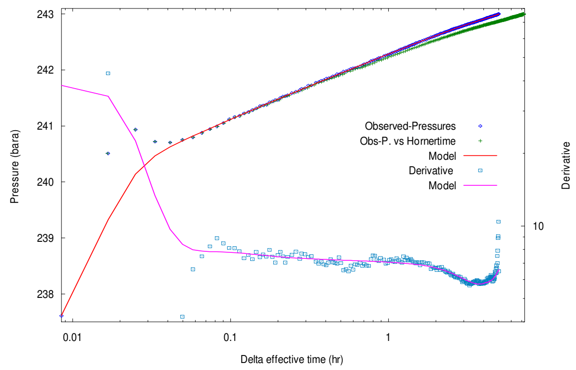

Figure-6 Horner Plot of BU

Note that both the Horner straight line and the derivative are plotted versus the logarithm of the effective Agarwal time. This time function is used in order to make the derivative plot the same as the standard Typecurves, developed for one constant flowrate. It compensates for all different flow periods. A more simple approach is the Horner effective time:

$$th = (tL * dt) / (tL + dt) \qquad [4]$$

with the flow period tL = Np/ql and with dt the shut-in time. Np is the cumulative production and ql the final flowrate. The green data points are plotted versus this Horner effective time. Note that only for long shut-in times both build-up plots do deviate. For the simple analysis of skin and permeability the Horner time approach is valid. For a detailed analysis of flow boundaries the Agarwal time is better, especially for recognizing the well/reservoir model from its typical shape of the derivative. The author will mail standard Typecurves on request.
The model matches the observed pressures of the BU rather well, except for the first 10 points. These points during the first 5 minutes of the BU show a pressure hump. This overshoot of the model is caused by the kinetic energy of the flowing water (similar as water hammer in too fast closed water pipes), which does increase the pressure in the well faster than that in the reservoir. This makes the first 3-6 minutes of the BU unanalyzable in all ESP produced wells. ESP pressures normally suffer also from an extra heating of the water

around the pressure gauge (only a few meters below the pump) due to the latent motor heat, causing the local water temperature to increase several degrees after motor switch-off.
The late BU shows the typical dip in derivative as indication of a flow barrier, just before the well-known doubling of slope of the Horner straight line. In this case this dip is caused by two parallel flow barriers: the channel in which the doublet is situated. The width of this channel agrees well with the one defined by the seismic map. The main uncertainty in the channel width of the model is caused by uncertainty in reservoir porosity, permeability anisotropy and total system compressibility. The interference test will define some of these parameters with more accuracy.
The strange upswing of the final 6 points is caused by the way the derivative is calculated and can be ignored.

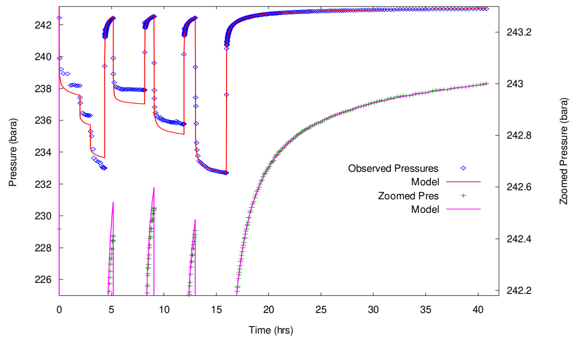

Figure-7 Match of all test data

Figure 7 presents the model match of the flowing and shut-in (BU) pressures. Note the poor match of the first two main flow periods. This rate-dependent pressure drop is caused by the friction over the screens and the vertical conduit up to the deep gauge. Matching each flow period separately by variation of only the skin resulted in Figure 8, indicating a damage skin of -1.5, apparently caused by a very successful clean-up.

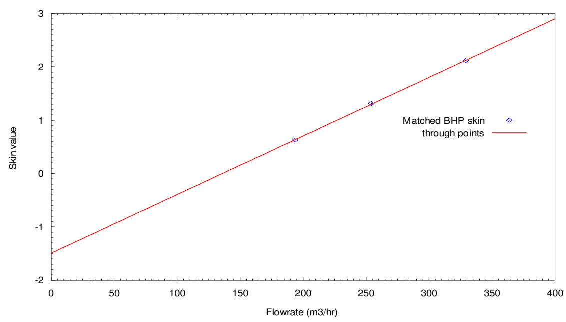

Figure-8 Skin vs. Flowrate

5. INTERFERENCE TEST

Just before the test of the second well GT_02 of a doublet, two accurate low-pressure gauges were installed about 30 m below the free water level in the first well GT_01, which had been tested a month earlier. With this well completely sealed from the atmosphere, variations of the gauge pressure can only be caused by variation of the reservoir pressure. The water column between gauges and reservoir acts as a constant pressure difference. Care should be taken to inspect if the gauge temperature is indeed constant. There is one correction required: The water entering the well at bottom is warmer than the water moving above the gauge. With a temperature difference of 70 C the density ratio is about 0.965, with which factor the gauge pressure variation should be multiplied.
The most important observation is whether there is any reaction in GT_01 on the flow of GT_02. If not, the project cannot continue as production and injection would take place in separate reservoir blocks with possible disastrous subsurface results. This should be a standard check by the Ministry of Mining.
Figure 9 presents the observed gauge pressures in a successful project with 234 bar added to the gauge data to represent the real reservoir pressure. Note the quick reaction on the flow in well GT_02.

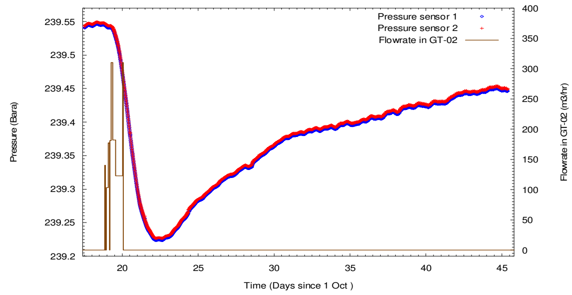

Figure-9 Pressure in well 01 by flow of well 02

The signal shows random variations around the expected, smooth signal. It took some time before it was realized that there had been some weather depressions during the test: it is the influence of the atmospheric pressure.
In Figure 10 the matched model response was subtracted from the observed pressures, resulting in the green line.

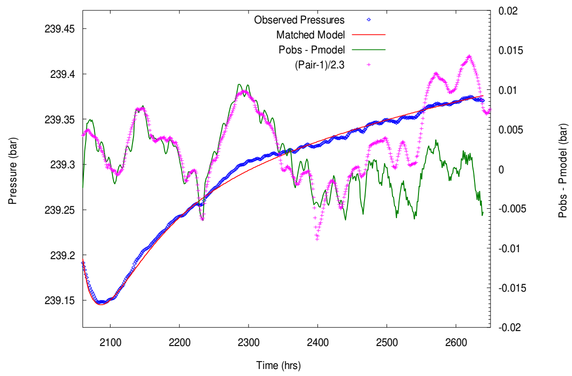

Figure-10 Match of atmospheric pressure

Plotting also the KNMI reported air pressure variation, divided by a factor 2.3 (purple points) proves this random variation to be caused by the air-pressure, exactly as the tide is seen in deep offshore oil/gas wells. From this factor 2.3 the pore compressibility Cf can be calculated:

$$Cf = Cw / (dpt/dpr - 1) \qquad [5]$$

The derivation can be found in its most complex form in Reference C, Langaas, 2005.
In equation-5 "dpt" represents the amplitude of the atmospheric pressure, and "dpr" the resulting pressure variation in the deep reservoir. After subtraction of the purple curve from the observed gauge data, the match

with the corrected pressures was much better, Figure-11: the green line is again the subtraction of the re-matched model response from the corrected pressures, revealing an influence of the tide in the North Sea (at a distance of 17 km), enlarged in Figure-12.

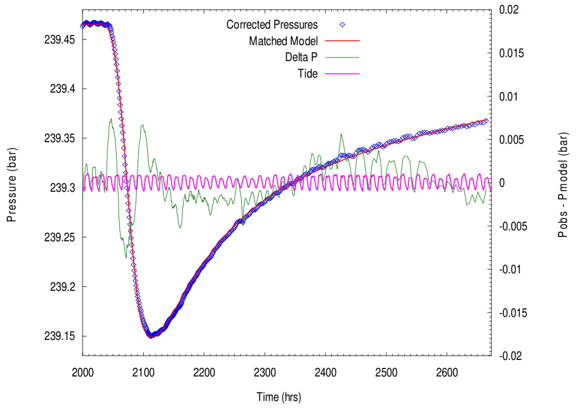

Figure-11 Improved match showing tide effect

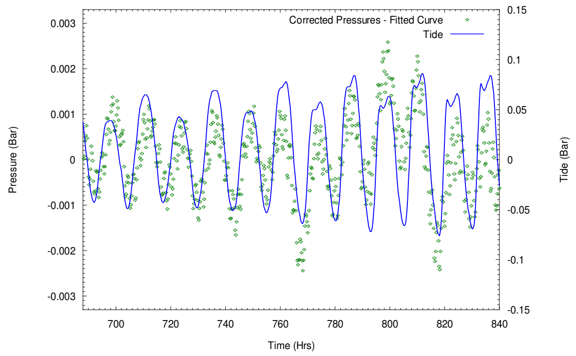

Figure-12 Enlarged tide effect, correlated with North Sea tide

In order to prove that this tidal influence is not the direct influence of the gravity disturbance by the moon, the tide effect in a well closer to the sea is presented in Figure 12: the influence by the complex tide currents in the North Sea can clearly be observed in this, much larger, tide effect in the reservoir pressure: the blue points are the reservoir pressure, the red line the reported sea tide nearby. The weight of the offshore tide moves apparently the ground surface as far away from sea as 17 km in the well of Figure-12. A subsurface communication is not possible, as a symmetrical pressure signal with a period of half a day would travel much less than 1 km in a deep reservoir.

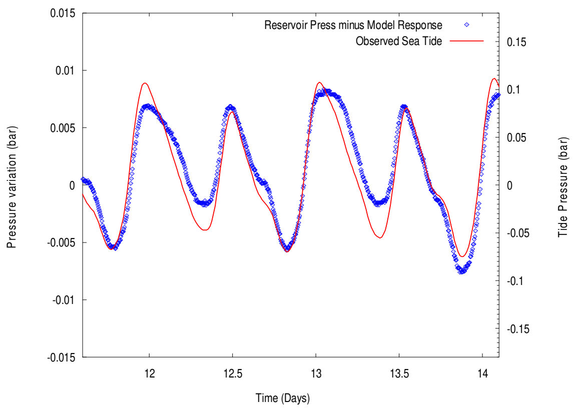

Figure-13 Tide effect in reservoir, 2.6 km from Sea

6. CONCLUSIONS

With the information provided in this paper, the author hopes to have contributed to a general improvement of hot-water well testing; especially with the correction for the cooling water column below the pressure gauge.

Interference testing should become an obliged (Ministry of Mining) part of the well testing program, providing essential information about the expected future performance of the doublet and about the safety for the underground.

The early detection of salt drop-out can prevent failure of the whole project.

Please Email the author if you are interested in the Interference Simulator programme or Typecurves, available for free.

A APPENDIX-A

Conversion from practical into SI units

Practical	into	SI	multiply by
m3/hr	into	m^3/sec	0.0002778
mD	into	m^2	0.9869 E-09
Bar	into	Pa	1. E-05
Psi^{-1}	into	Pa^{-1}	1.4504 E-04
cP	into	Pa.sec	0.001

B APPENDIX-B

Interference Programme "Channel"

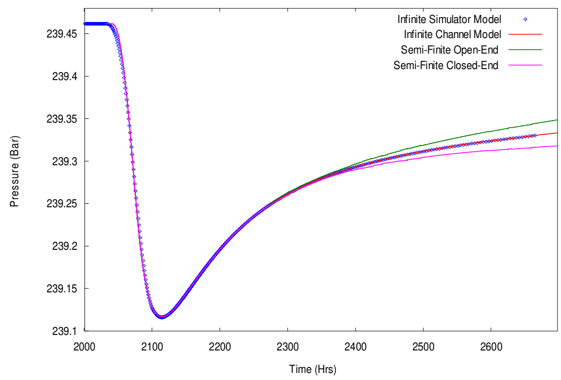

Figure-14 Interference in flow channel

Figure 14 compares the output of a small computer programme "Channel" with that of a complex well-test analysis program for an interference test in a semi-finite channel (between two parallel sealing faults) with one channel end open to radial inflow, the green curve. This open end is normally simulated by specifying this end as a so-called "constant-pressure" boundary, applying a minus sign before the image wells that are used to construct such a flow-boundary. The red curve is for an infinite and the purple curve for a semi-finite channel (closed-end with a + before the image wells). This program was written for this paper in order to help engineers with a low budged to interpret the results of an interference test. If interested, please contact me by Email and I will mail the executable to you.

C APPENDIX-C

Gnuplot Command File

```
reset
set title "Figure-1  Correction of gauge movements in build-up""
set xlabel "Time (Days since 1 July)"
set ylabel "Pressure Difference (Bar)"
set xrange  [ 4.3:5.25]
set yrange  [ -0.55:0]
set xtics
set ytics
set mxtics
set mytics
set key 5.15, -0.3  ;set pointsize 0.7
set nologscale xy
f(x) = a + b*(x-c)**e + d*log(x-c)
a = 244.3 ; b=0.0346; c=4.35; d=0.103; e=0.0005
fit [4.4:5.2] f(x) "BU_DATA.out" using 2:4 via a, b, c, e, d
plot "BU_ DATA.out " using 2:($4-f(2)) axes x1y1 title "Pobs-fit" with points,\
    "BUcor_ DATA.out"  using  2:($4-f(2))  axes  x1y1  title "Corrected Pobs-fit" with lines
```

BU_DATA.out:

Nr	Time (Days)	Flow	Gauge Pressure	Gauge Temp (C)
912	*4.2168403E+00*	*0.0*	*2.3406049E+02*	*8.9895798E+01*
913	*4.2168980E+00*	*0.0*	*2.3408789E+02*	*8.9899696E+01*
etc				

D APPENDIX-D

Water Density Curves

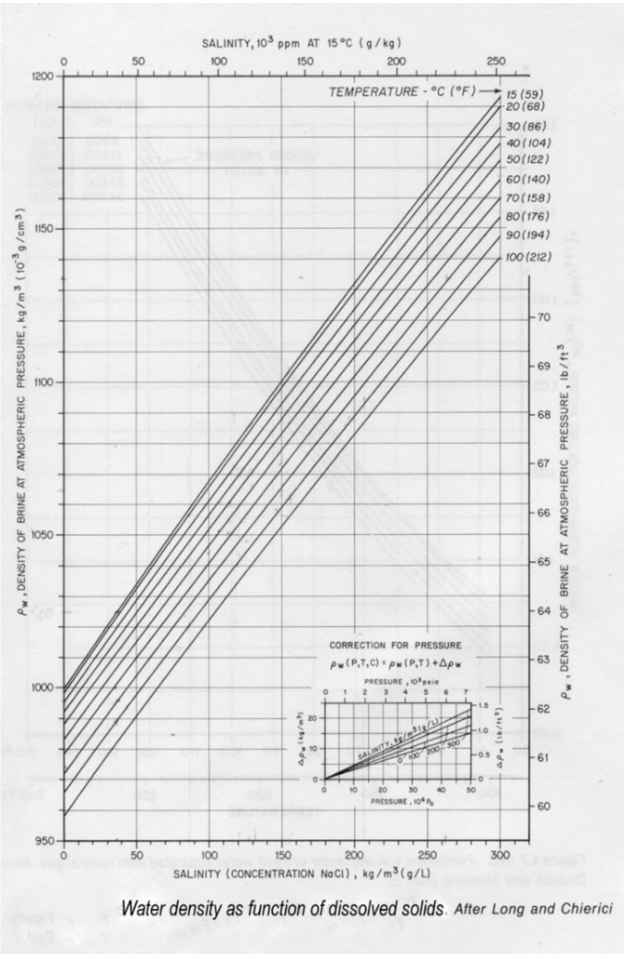

Figure 15: Brine density as function of dissolved solids concentration.

E APPENDIX-E

Horner Analysis Method

Instead of using an analytical model in a computer program, the pressure data can also be analyzed with the old method of the so-called Horner-line: K.H/mu = 515.8 * Q / slope, if pressure is in Bar, Q in m3/hr, H in m and mu in cP.
This is demonstrated in the example of a recent test with an analyzed (with a sophisticated welltesting program) K.H of 155 mD.m (1.324 D * 117 m).
Figure-15 was created by plotting the bottom gauge data of the final build-up versus LOG {(tp + dt)/dt} and fitting a straight line through the plotted points.
The tp has been calculated as Np/Qf, with Np the total cumulative production and Qf the final flow rate of 452 m3/hr. The unit of time is irrelevant, as long as it is the same for tp as for dt.
The intersection with the Y-axis of this line is the static reservoir pressure at gauge depth. From the slope the K.H/mu is obtained: with a mu of 0.46, the k.h = 515.8 * 452 * 0.46 / 0.577 = 186 D.m, an error of 20%. But most of this error is caused by the cooling of the water column below the gauge, which was taken into account in the model match.
The second data set in Figure-16 are therefore the build-up pressures extrapolated to datum depth correcting for the cooling of the water column of 221 m between gauge and datum depth. This line is indeed steeper, slope of 0.644 bar/cycle, because the colder, later, pressure data are increased more than the earlier pressures.
The k.h is now 166 D.m., only 7% wrong, caused only by the approximation of the complex rate history into one single flowrate.
The skin follows from the last flowing pressure Pwf, the pressure (P1hr) <u>on the straight line</u> at LOG(tp+1) the slope of the fitted line, ms, and the reservoir/well data like, k (md), mu (cP), Ct (psi-1), phi and Rw (ft):
S = 1.151 * [(P1hr – Pwf)/ms – LOG {k / (phi * mu * Ct * rw**2)} + 3.23]
Application of this equation on the corrected pressure slope of Figure-16 (plotted with 23 bar subtracted!), results in Pwf = 227.06, P1hr = 234.35, k = 1.419 D, phi = 0.2, Ct = 8.35E-6 psi-1, mu = 0.46 cP and rw = 0.41 ft. With ms = 0.577, S = +5.8. Both this skin and the k are a little too high due to the simplified analysis. This can be improved by changing the well test program, using only 4 flow periods without any intermediate shut-in: clean-up of 3 hrs, 40% of Qmax for 2 hours, 2 hrs at 70% with sampling at end and 4 hrs at Qmax, followed by a final build-up of about 14 hrs.

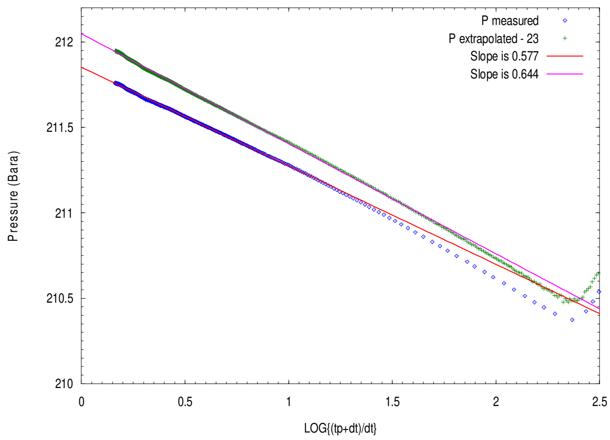

Figure 16: Horner plot of raw and corrected BU data

The GNUPLOT command file is printed below. GNUPLOT can easily be found on and downloaded from the Internet.

Flow Barrier at 350 m, Figure 17

The advised test sequence with 4 flow periods of total 11 hrs and one final build-up of 14 hrs has been used in a model with one flow barrier at 350 m distance. The h is 100 m and K 1.0 Darcy. The porosity 20%, Ct is 9 E-6 psi-1, rw 0.4 ft and mu 0.46 cP. The static reservoir pressure Pi is 210 bar. The maximum flowrate is 350 m3/hr.

The simulated pressure response has been analyzed with the Horner method, with tp 7.8964 hr.

The fitted slope of 0.787 bar/cycle results in a k*h of 105.5 D.m instead of 100 D.m. The error made by using the single rate tp is thus only 5.5%.

The green line has a fixed slope of 2 * 0.787 = 1.574 and has been drawn through the final point of the build-up.

The two straight lines intersect at x = 0.32. From the definition of x = LOG {(tp + dt)/dt} follows:

dt = tp / $\{10^{0.32} - 1\}$ = 7.25 hr. The distance to the flow barrier is then d = √ {1.38E-5 * k * dt / (phi * mu * Ct)} in meters if dt in hours, k in mD, mu in cP and Ct in psi-1.

D is thus 348 m! Not bad for such a basic approach.

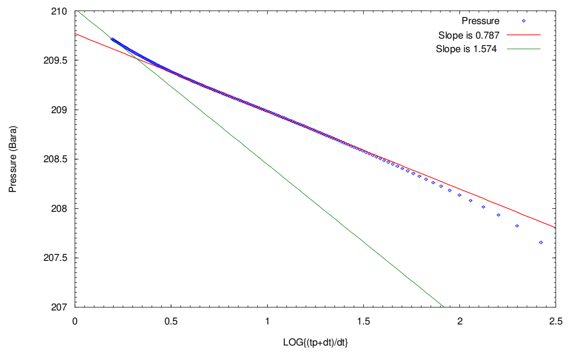

Figure 17: Effect of flow-barrier on Horner plot

Command file: "FIGbu.plt". Just open this .plt file in GNUPLOT and the plot appears. Copy and save as text file but with extension .plt. The measured BU data are in file "bpbu.dat", the corrected pressures in "bhpcbu.dat". Start GNUPLOT and open this "FIGbu.plt" file.

```
reset
set xlabel "LOG{(tp+dt)/dt}"
set ylabel "Pressure (Bara)"
set xrange  [ 0.0:2.5]
set yrange  [ 2.10E+02: 2.122E+02]
set xtics
set ytics mirror
set mxtics;set mytics
set key    ;set pointsize 0.5
set nologscale y ; set nologscale x
f(x)=a+b*x
fc(x)=c+d*x
a = 211.853; b=-0.577; c=211.853; d=-0.693
fit [0.15:1.1] f(x) "bpbu.dat" using (log10((0.46117+$2-3.9167)/($2-
3.9167))):4 via a, b
fit [0.15:1.3] fc(x) "bhpcbu.dat" using (log10((0.46117+$2-
3.9167)/($2-3.9167))):($4-23.0) via c, d
plot "bpbu.dat " using (log10((0.46117+$2-3.9167)/($2-3.9167))):4
title "P measured" with points,\
  "bhpcbu.dat" using (log10((0.46117+$2-3.9167)/($2-3.9167))):($4-
23.0) title "P extrapolated - 23" with points,\
    f(x) title "Slope is 0.577" with lines,\
    fc(x) title "Slope is 0.644" with lines
```

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