Analysis of Welltest LIR-GT-01

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Summary

Well LIR-GT-01 was production tested by a 3 rate test with each flow period followed by a short build-up for a total period of some 11 hours, followed by a shut-in period of 1day. The ESP generated production rates varied between 190 and 340 m3/hr. Cumulative water produced was about 3350 m^3. The production test was followed by an injectivity test of about half a day.

Following are the main conclusions:

- The average reservoir permeability is 1000 mD assuming all seven sand layers to contribute to flow.
- The skin is low at S=2.2 and rate-dependent, possibly the flow resistance of the screens. The fixed (reservoir) skin is negative at -1.3.
- Two parallel flow barriers are evaluated at distances of 750m and 1250 m from the wellbore.
- The static reservoir pressure at 2400 m tvBRT is 245 bara.
- The reservoir temperature is 90.1 ºC.
- The correction for the changing temperature of the water column between the ESP and top reservoir appears to be working reasonably well
- The transient flow capacity (PI) after 41 hours flow is 23 m^3/hr/bar at ESP depth, 28 m^3/hr/bar at the inside of the screens and 40 m3/hr/bar at the outside of the screens, if the rate dependent skin is completely caused by the screens.
- The (still increasing) transient injectivity (II) at the end of the injection test is only 5 m3/hr/bar, caused by an effective skin of 58.
- The injectivity test shows continuous decline in skin during the entire injection period. Given that a low skin of 2.2 was observed during the production test, it is believed that surface lines etc. were not fully cleaned–out (grease, etc) before the injection test took place.
- Allowing for regular filter clean-outs, it is expected that the injectivity index of the well will increase further.

Resultaten van de puttest

Gegevens voor test interpretatie	Waarde	Dimensie
Naam van de put	LIR-GT-01	
Coördinaten van de put (X, Y)	51°58'39.975"N	4°16'57.311"E
Top aquifer	2651	m (langs boorgat)
	2387	en m (TVD)
Basis aquifer	2830	m (langs boorgat)
	2528	en m (TVD)
Dikte Aquifer	70	m (TVD)
Netto/bruto aquifer	50	%
Gemiddelde porositeit aquifer	16.4	%
Zoutgehalte formatiewater (TDS = total dissolved solids)	140,000.	ppm
Maximum temperatuur geproduceerde water[1]	90	ºC
Diameter boorgat bij aquifer	8.5	Inch
Top productie-interval/filter	2602	m (langs boorgat)
	2353	en m (TVD)
Basis productie-interval/filter	2868	m (langs boorgat)
	2553	en m (TVD)
Filter weerstand	3.5	bar @ 332 m3/hr
Filter weerstand	2.7	bar @ 254 m3/hr
Filter weerstand	2	bar @ 194 m3/hr
Locatie pomp	711.3	m (langs boorgat)
	710.43	en m (TVD)
Locatie meetsonde voor druk	2398	m (langs boorgat)
	2196.22	en m (TVD)
Clean up gegevens		
Ponpdruk	55	bar
Debiet vs. tijd	330	m3/uur
Duur	4	uur
Meetreeksen Puttest[4]	Eind pompdruk, bar	Eind Debiet, m3/uur
Flow 0	66.2	0
Flow 1	61.9	194
Flow 2	59.1	254
Flow 3	54.8	332

[1] Deze temperatuur wordt als gemiddelde aquifer temperatuur beschouwd

Uitkomsten test interpretatie en analyse		
Permeability thickness kH	70	Dm (Darcy-meter)
Aangenomen H	70	m
Permeability k	1000	mD
Reservoir Skin S	-1.3	
Totale effectieve Skin	2.2	@ 332 m3/hr
Productivity Index (P.I.) (ESP level)	23	m^3/uur/bar
Productivity Index (P.I.) (at wellbore)	40	m^3/uur/bar

Zie hoofdstuk 9 voor de put completie.

Contents

1 Introduction

Well LIR-GT-01 was production tested from 3-7-2014 13:14 to 4-7-14 5:12, followed by a shut-in period of 1day. ESP generated production rates varied between 190 and 340 m3/hr. Cumulative water produced was about 3350 m^3 when all zero rate entries during the flow periods were corrected.
The pressure and temperature data were recorded both by the ESP gauge and a deep gauge on wireline.

The ESP pressure sensor is at 710.4 m tvBRT; the deep gauge at 2196.2 m tvBRT. The well was produced mostly from the Delft sandstone, covered by screens, from a depth of 2353 to 2553 m tvBRT (2606 – 2868 m ahBRT).

The pressure difference during the build-up between the deep gauge and the ESP was used to correlate the correction formula as used in the MDM area on the ESP temperatures. The resulting function was then used to correct mainly the ESP pressures, but also the deep gauge pressures, down to a datum depth of 2400 m tvBRT.

After the production test on 6/7/2014, 1040 m3 water was injected back into the well, using the mud pump of the drilling rig. The 10 hours of injection rates and surface pressures have been matched with the same model as matched on the production test.

2 Reservoir data

The porosity of the Delft sandstone has been estimated with the (exponential) GR-PHI method of TNO because no direct porosity measurements are performed for this well. The porosity is estimated at 16.3%. But also 20% has been used in the analysis in order to test the sensitivity of the analysis results on the porosity value. Net reservoir thickness of the separate sand layers behind the screens is estimated from the gamma ray log as a total of 70 m (230 ft). [1]

The wellbore radius Rw has been set to the bit size of 8.5”, or 0. 354 ft.
In view of the deviation of the well with an average angle of 40.2 degrees through the Delft Sandstone, the wellbore radius was adjusted to $Rw*\sqrt{\{(1+1/\cos\alpha^2)/2\}} = 0.412$ ft, for analysis with a vertical well model.
The reservoir temperature is estimated at 91 ºC. The salinity is obtained from the matched formula as a water density of 1.0403 * 10197.16, or 1061.9 kg/m3 at 91 ºC This is consistent with a water salinity of 155 gr/ltr NaCl (140000 ppm) and a water density at 15 ºC of 1102 kg/m3.

Standard tables show for this salinity a water compressibility of 2.37E-6 psi^{-1}, and a water viscosity of 0.46 Cp. The pore compressibility had been originally assumed to be 3E-6 psi^{-1}. As this low compressibility resulted in too large distances to flow barriers, it was increased to 9.E-6 psi^{-1}, more likely for this high permeability sandstone. This appears to be confirmed by the match of the atmospheric pressure in Fig-2C below.

[1] *The geothermal wells of Honselersdijk and De Lier have high permeability Delft Sandstones, while its porosity is modest. In other words there seems to be a discrepancy between the high permeability calculated from the well tests and the available porosity information. At PanTerra there is doubt about the porosity value of about 17%, this may be too low. Considering the high permeability, porosity values in the twenties seem more likely. Unfortunately geothermal operators do not run wireline logs from which reliable porosity values can be calculated, because such wireline logs are deemed too expensive, the result is that important information on the reservoir is lacking.*

3 Correction for water column cooling on gauge data

The pressures of the downhole gauge were correlated with the ESP pressures as function of the ESP temperature in Fig-A. The resulting correction formula, after removing the first 26 build-up points, is:

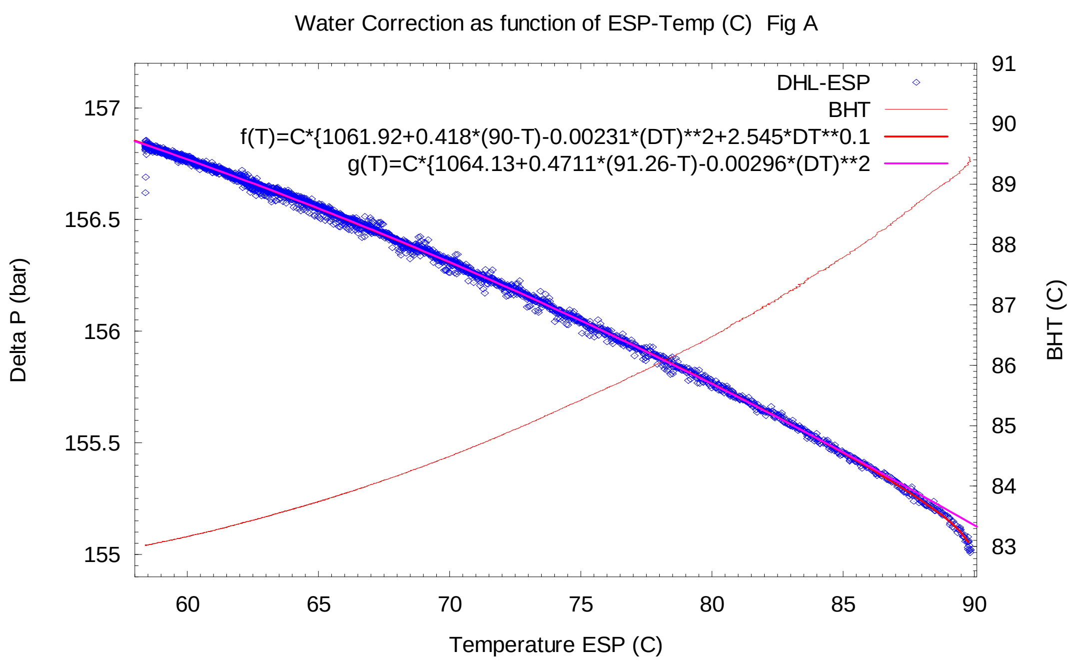
$\Delta P = CDC * L * [1061.92 + 0.418 * \Delta T - 0.00231 * \Delta T^2 + 2.545 * \Delta T^{0.1}]$,

With ΔP the pressure correction, CDC a constant [CDC= 9.8063E-5 if pressure in bar and L in meters], L the vertical depth difference between datum and ESP depth, and ΔT the difference between the maximum and current ESP temperature in ºC.

As maximum temperature 90.0 ºC was used, giving the best curve fit at the high temperatures.

This formula corrects thus from ESP to BHP depth. As the last term to the power 0.1 had to be added to correct for the early ESP temperatures after shut-in, which are above the water temperature due to the motor heat, this extra term should not be used for the extrapolation from BHP to datum depth. The second function, g(T), was therefore only matched on the temperatures up to 86 ºC. This function has been used to correct the BHP to datum depth; Tmax is now 91.26 ºC.

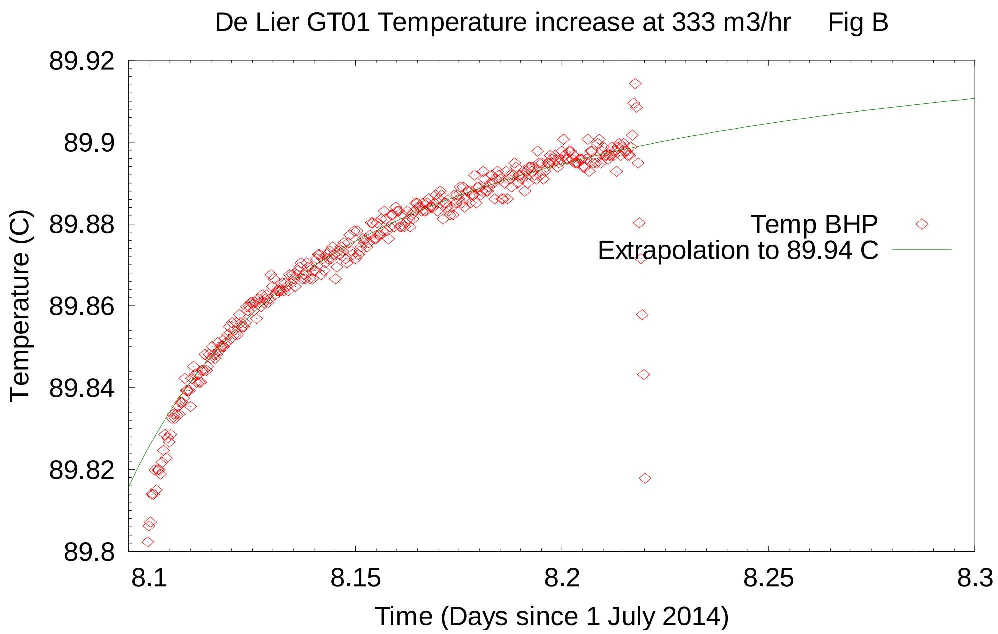
The blue points are the pressure differences between BHP and ESP, with the two fitted curves through those points. The first red line is the BHT (right-hand axis) versus the ESP temperature.

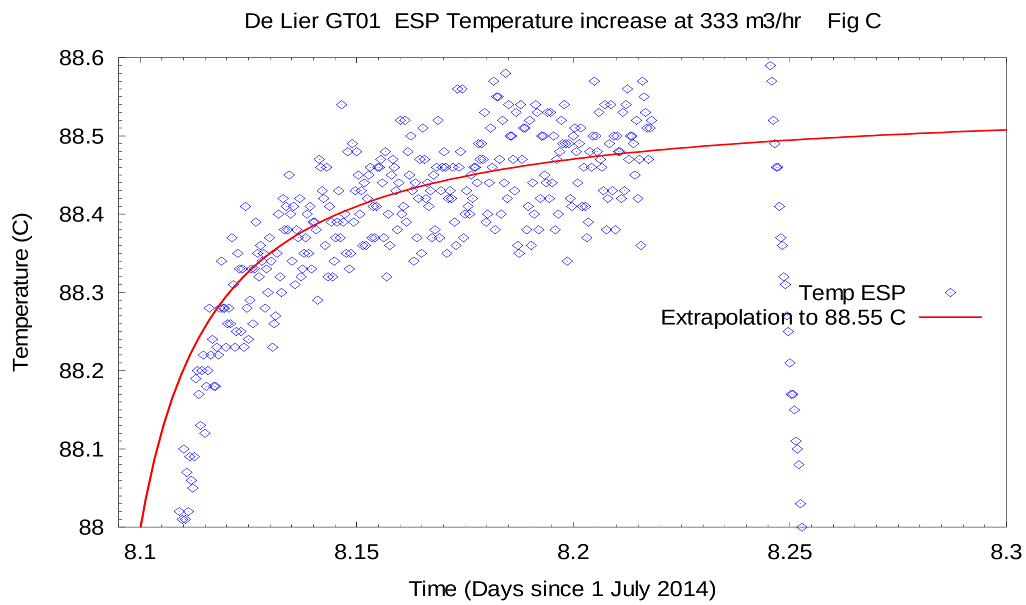


The maximum expected future water temperatures at the downhole gauge depth is obtained by extrapolation of the recorded temperature during the 2.9 hours long flow period at the highest rate of 330 m3/hr in Fig B, resulting in 89.94 ºC.

Fig C presents the same extrapolation for the ESP temperatures, resulting in 88.55 ºC.

This is a difference of 1.39 ºC over a vertical distance of 1485.8 m. Extrapolation to 2400 m tvBRT, 203.8 m deeper than the BHP gauge results in an expected reservoir temperature at datum of 90.13 ºC.





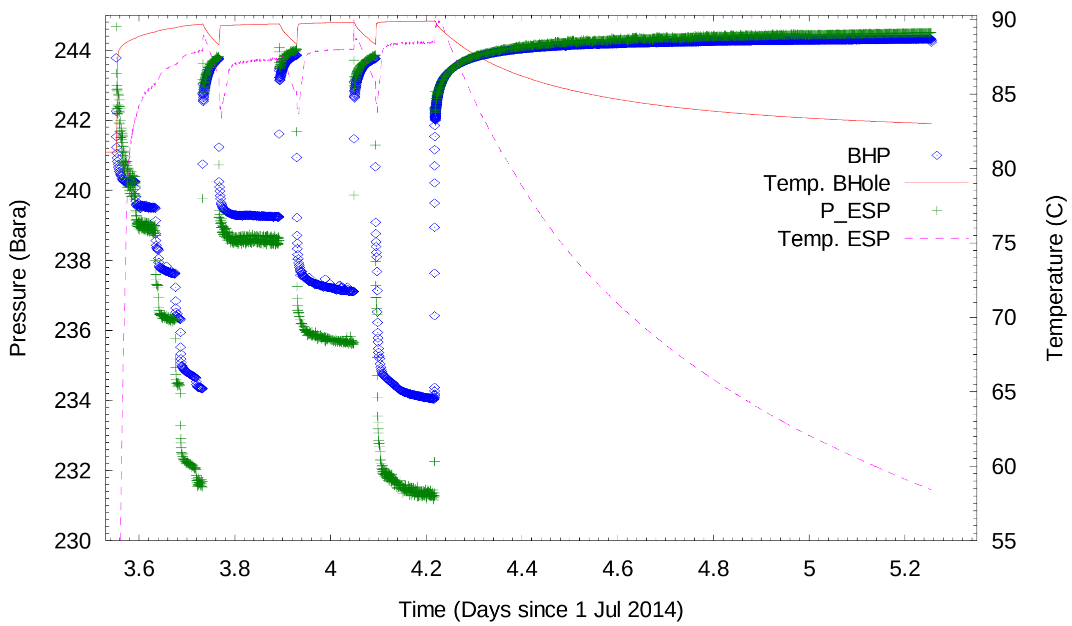
4 Pressure recordings

Fig-1 shows the uncorrected downhole (BHP) and the ESP data (with 155 bar added for plotting in same figure), plus the rates. During the final three test flow periods there seem to be errors in the rate measurement, as there are short periods with zero rate without any sign of build-up. These rate errors have been corrected.

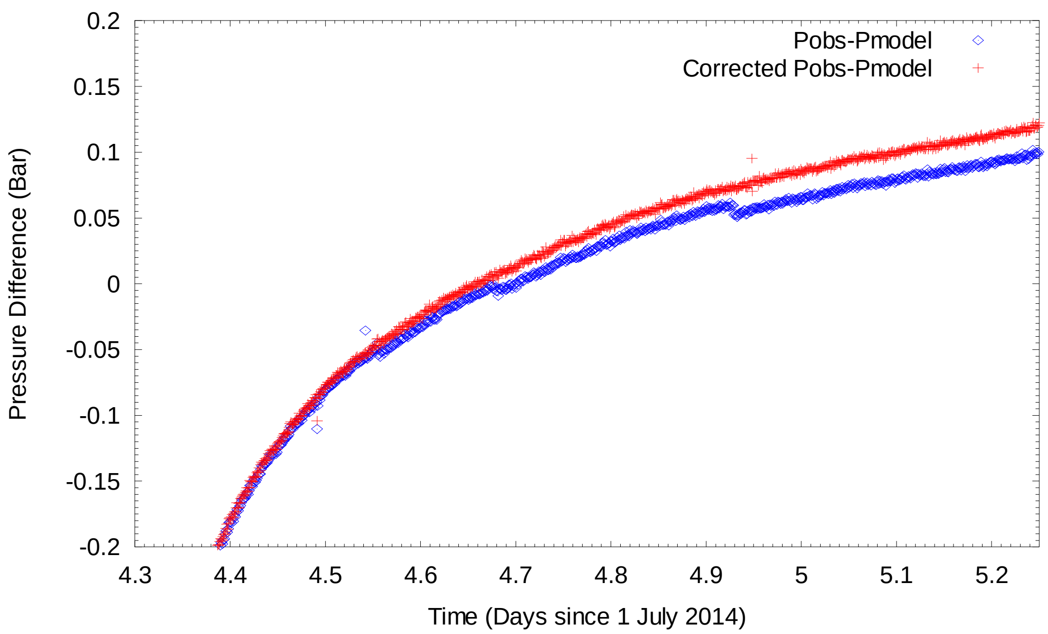
In Fig-2 both gauge data are corrected for the water column weight to a depth of 2400 m tvBRT, and are nearly the same. The extra drawdown on the ESP pressures is the vertical flow resistance of the casing.

In Fig-2B, the build-up data are plotted on a larger vertical scale by first matching a curve through the data and next plotting the difference. This large scale shows three downward jumps in the pressure, caused by the sudden upwards movement of the downhole gauge as the wireline shrinks with declining temperature. This movement is always in sudden jerks caused by the difference between static and dynamic friction. The red points are the BHP's with these jumps corrected.

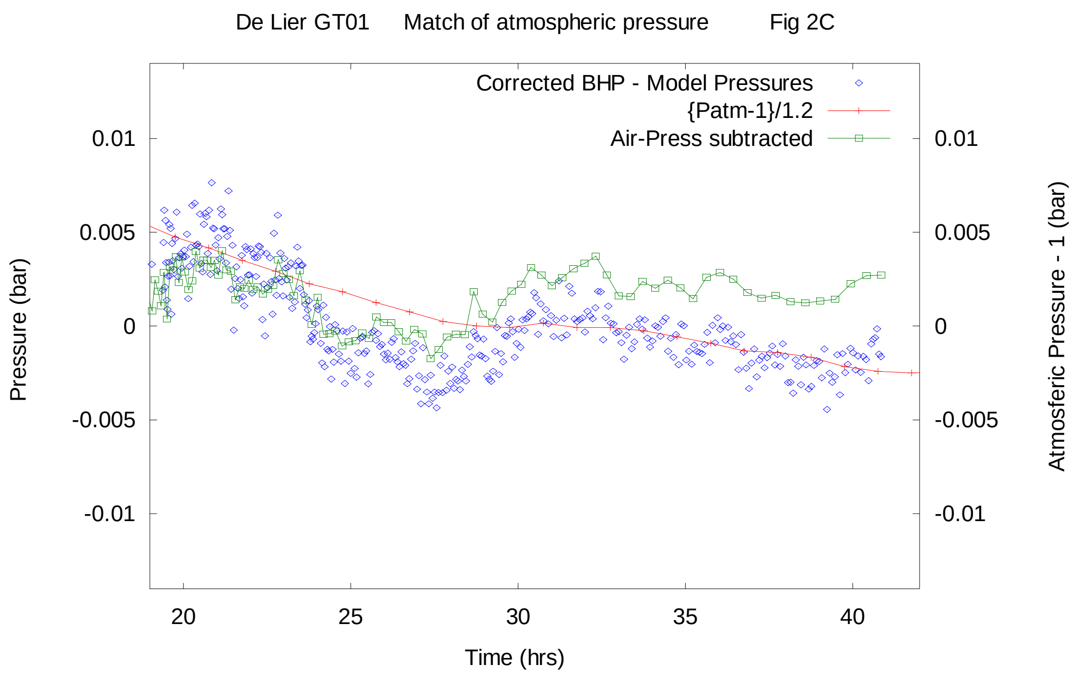
De Lier GT01 Corrected BHP and ESP Gauge Data Fig 2



De Lier GT01 Wireline movement Fig 2B



Subtraction of the air pressure did change the build-up slightly, see Fig 2C, but did not change the analysis results. The dip in pressure between times 25 and 30 is apparently something else.



5 Analysis method

The analysis is carried out by the match of the most appropriate analytical well/reservoir model with the total test history. In this way, no approximations have to be used, as for the model response the flow equations are solved with great precision for the reported flow rates. It should be noted that each pressure point measured in a well depends on the total previous rate history of that well, both in the real reservoir as in the analytical model. Analysis of only one rate period can thus give only an approximation of the real reservoir/well parameters.

As no model for a deviated well is available, a vertical well model has been used, based on the assumption that the flow in the reservoir at some distance from the well will be horizontal, as the vertical permeability is normally lower than the horizontal one in sandstone. The matched-model response for short times can be expected to deviate somewhat from the observed pressures. But these early build-up pressures are also expected to be influenced by cold water, falling down from the annulus above the pump, by water hammer and by the latent motor heat.

6 Analysis of corrected pressure data

The pressures of the BHP gauge, corrected for the water column temperature and the wireline shrinkage, have been analysed as presented in figures 3 and 4.

The build-up pressures show radial flow with some other influence at the end. This deviation from radial flow could be matched by two relevant models:

Two parallel flow barriers forming a flow channel of 2000 m width with the nearest fault at 750 m in a 1000 mD reservoir with a skin of 2.2.
Increasing the porosity to 20% resulted in nearly the same results with a channel width of 1900 m, nearest side at 770 m and S of 2.3.

The other model simulates a reservoir of two layers, with 40% of the net sand producing with a low skin of 0.3 and a permeability of 1.5 Darcy and the rest with a skin of 11 and a permeability of 840 mD (the average permeability is 1100 mD). The vertical permeability between the layers is 3 mD.
Variations on the thickness ratio are possible, as is the option of a combination of both models: two layers plus a boundary, but a single layer with channel seems more likely in view of the seismic map, presented at the end of this report.

Fig 3 presents the Horner plot plus derivative of the main build-up. The channel model matches all build-ups very well, as is shown in the linear-time plot of the whole test match, Fig 4. The mismatch of the low-rate flow periods indicates the presence of a rate-dependent skin. Matching the final point of the lowest, first, test period results indeed in a reduction of the skin from 2.22 to 0.77. As a choke will result in a rate-dependent skin, the matched model skin is probably caused by the screens.
The purple derivative is the BHP gauge corrected to 2400 m with a fixed delta-P value, indicating that the temperature correction of 204 m down to the datum depth of 2400 m tvBRT does not make much difference.

From Fig 3 it may be concluded that the channel model is more likely, as it matches the derivative better. The early pressure hump during the first 2 minutes after shut-in is probably caused by the kinetic energy of the water, compressing the gascap in the annulus, as it appears also on the ESP pressures. Such a “water-hammer” hump is normally very short and high, but is increased in time and reduced in peak pressure by the gas (nitrogen and methane) in the top of the annulus.

Figures 5 and 6 present the analysis of the corrected ESP pressures. Only one model with a single flow barrier at 700 m has been matched: permeability 875 mD with a skin of 3.5. Matching on the lowest test rate, the skin reduces to 1.0, similar as with the BHP pressures. The difference with the skin of the BHP pressures is the friction of the vertical flow conduit between BHP and ESP. Also with these ESP pressure, the first 4 build-up pressures show a water-hammer hump and can thus not be matched.

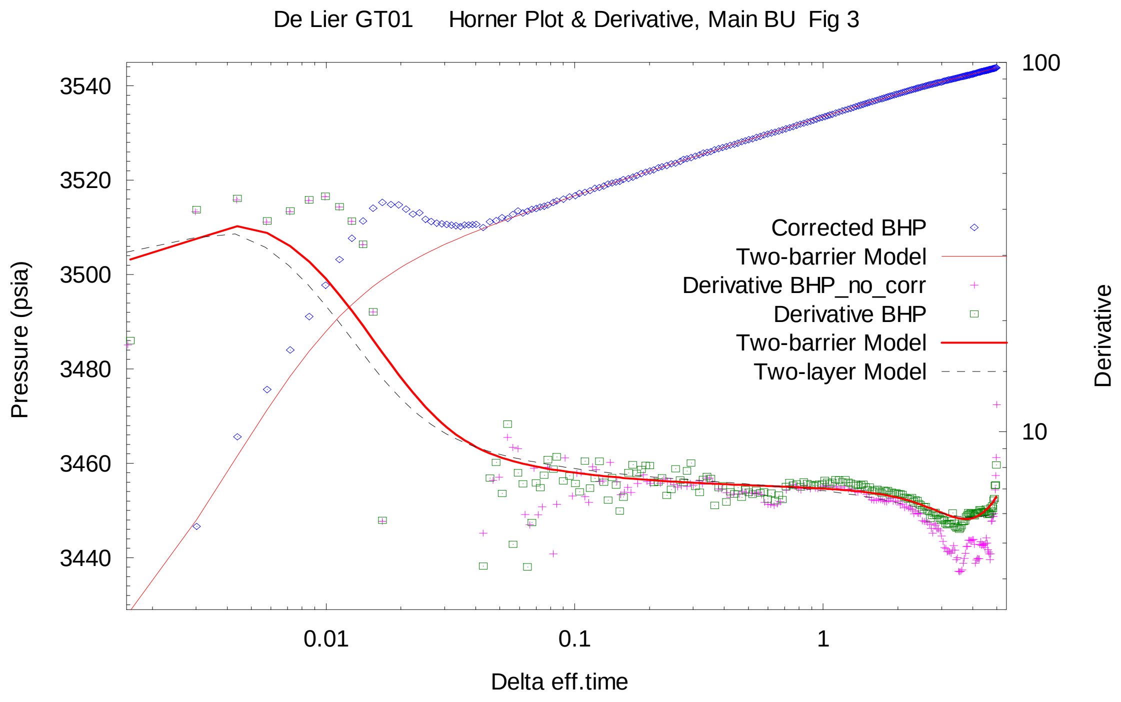
The build-up pressures up to 1 hour after shut-in deviate markedly from the downhole pressures. This has to be caused by the increase in ESP temperature during the first 40 minutes of the build-up of about 1.5 degree above the final flowing temperature. This is caused by the extra heat generated by the pump motor. During flow this heat is removed by the water. This cooling stops as soon as the well is shut-in, resulting in a temperature increase of the direct environment of the motor.
Indeed, at the shut-in after the lowest rate period, the temperature increase was only 0.3 degree, as the motor used much less electrical power.
Due to this too high temperature, the correction formula does not work properly.

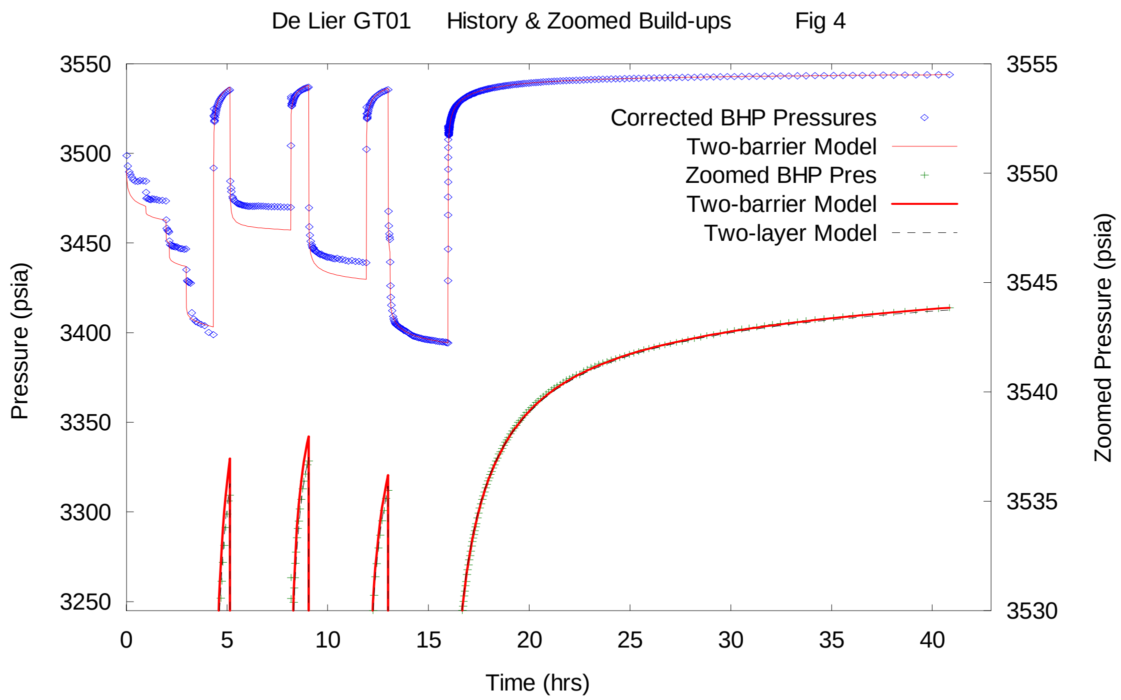
The static reservoir pressure at 2400 mtv is 3550 psia (245 bara).
The transient productivity index (PI) after 41 hours is 295 b/d/psi (28 m3/hr/bar) if based on the downhole gauge.
The rate dependent skin is equivalent with a pressure drop of 0.4 bar at 194 m3/hr, 1 bar at 254 m3/hr and 2.1 bar at 332 m3/hr. These values correspond with a fixed (mechanical) skin of -1.3 and a rate dependent skin of 0.0105 hr/m3.
With only the (negative) mechanical skin, the PI is 40 m3/hr/bar.

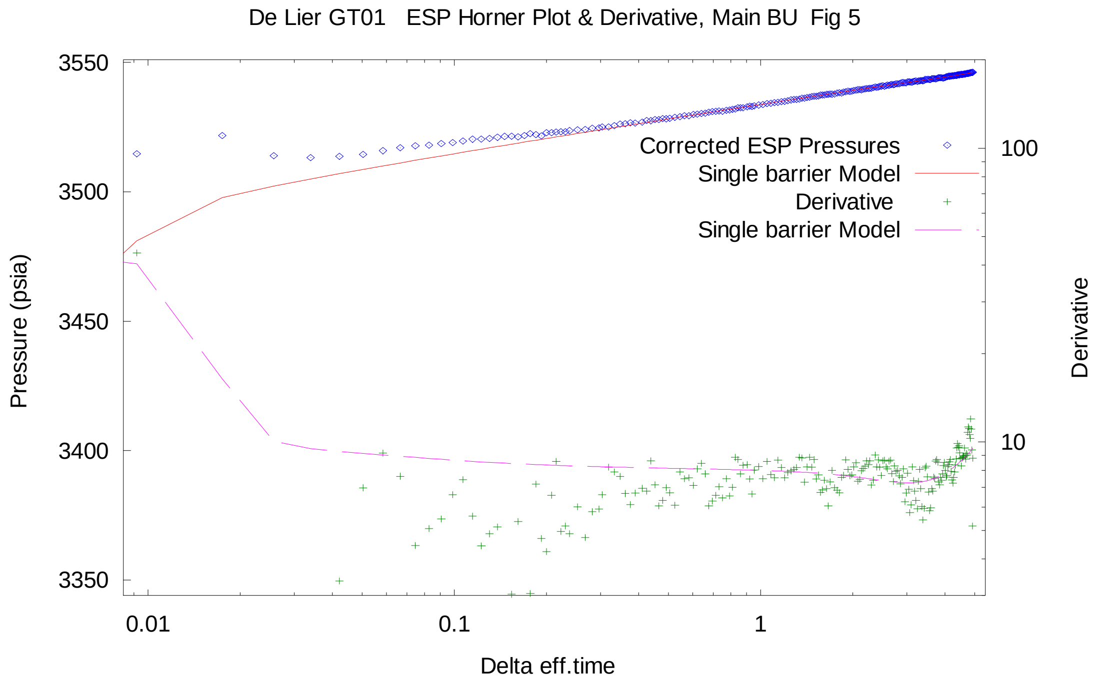
Due to the friction in the casing, the ESP pressures result in a PI (after 41 hours) of only 235 b/d/psi, or 22.6 m3/hr/bar. At ESP depth the pressure drop over the screens plus the vertical flow conduit is 0.6 bar at 194 m3/hr, 1.9 bar at 254 m3/hr and 4.0 bar at 332 m3/hr.

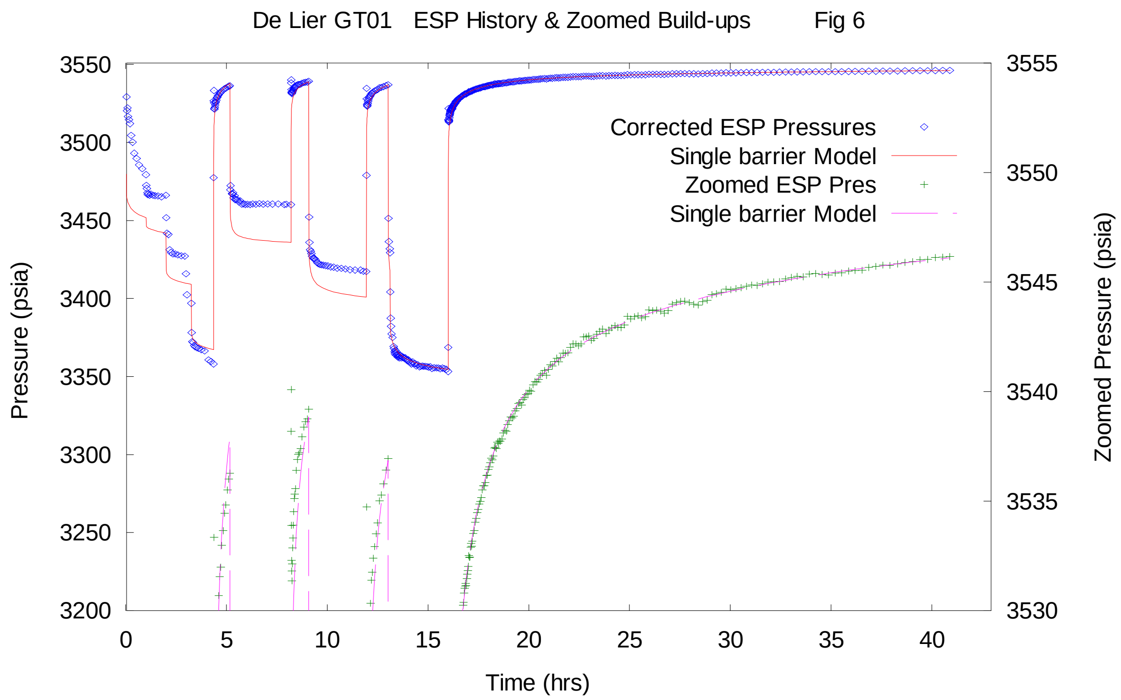
It should be noted that all above PI values are transient, and thus still declining.

The free water level at the end of the build-up period is calculated at 93 m tvBRT, based on the static ESP pressure of about 66.2 bar, the ESP depth of 710 mtvBRT, an assumed average temperature of 30 ºC of the water column above the ESP and a water density of 1094 [93 = 710 – 66.2/(1.094*0.098067)].









7 Conclusions and Recommendations

The derivation of an equation to correct ESP pressures for the changing weight of the water column down to the reservoir seems to work reasonably well (12% lower permeability), although the bottomhole pressures still give better results. This is not only caused by the water column weight correction but also by the lower gauge resolution.

The distances to both flow barriers are somewhat larger than the distances to two faults on the map, see figure 10 below. This may indicate that the used pore compressibility is still too low.

The match of all flow periods in Fig 4 shows that there is no clean-up during the production test, as then the first flow periods would have shown pressures below the matched model response. As they are above the model response there seems to be a rate dependent skin, probably caused by the screens in this high-permeability reservoir.

During the test flow periods there were zero rate entries in the data sheet, without any sign of a build-up in the pressures. These false zeros were given the average rate of that flow period.

The extra temperature correction formula for the BHP down do datum did hardly change the analysis of the downhole data. Also, the 26 early ESP pressures after shut-in for the main build-up are indeed poorly matched. It would be better if the temperature sensor could be about 20 meters below the pump.

The match of the final flow period is very good, both for the downhole as the ESP pressures. The short build-ups in between the flow rates are also well matched but do not contribute much to the test analysis. In fact, this time could have better been used for a longer maximum rate period, which has been rather short at 2.86 hour. The short build-up after the clean-up however, can provide useful information about boundaries. The presence of at least one extra short flow period at a lower rate (e.g. 40% of the maximum) is useful to determine the presence of a rate dependent skin.

For the next test a test scheme is proposed of 3 hours clean-up (2 hours of increasing motor power ending with 1 hour at maximum rate), 2 hour2 initial build-up, 2 hours at 40%, 2 hours at 70% and 6 hours at highest rate, followed by 12 hours build-up (if only the ESP pressures are taken; with a downhole gauge the build-up should be 24 hours). The highest test rate should be selected on the basis of the total storage capacity for the produced water. The maximum clean-up rate should be the real maximum.
The final test rate should be as long as possible and at a constant rate, as it may be the best period for analysis if only the ESP pressures/temperatures are available due to the nearly constant temperature and the high reservoir transmissibility (hardly any decline in flow rate during a fixed pump frequency period).

During the test of LIR-GT-02, it is advised to place two pressure sensors some 10 – 20 m below the free water level in the annulus in order to register the interference between both wells. From this interference signal, the geometrics of the flow area around both wells can be deduced, required for a good long-term hot water cycling forecast. These pressure sensors can be removed for analysis only three weeks after the production test in GT02. GT01 must stay completely shut-in all this time.

8 Injection Test

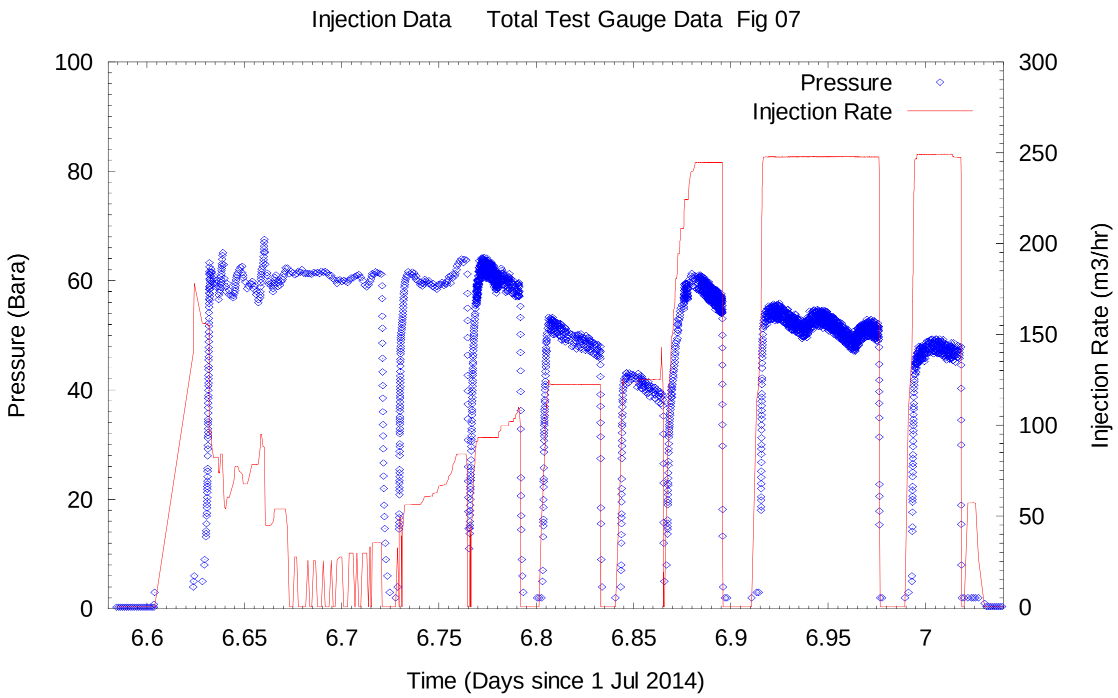
After the production test, water was injected back into the reservoir with the mud pump, measuring the injection rate and pressure, see Fig 7.
Surprisingly, the injection pressure was directly at maximum (~ 60 bar) at low rate. But during further injection the injectivity improved continuously.

For water with a salinity of 155 gr/ltr, the density at 30 ºC is 1094 kg/m3. With a cold water column of 2400 m, a constant Δp of 1.094 * 2350 * 0.098067 = 257 bar had to be added to the surface pressures.
At the start of the injection, the temperature in the well is on average some 60 ºC, with an average water density of 1080, resulting in a Δp of 254 bar. The extra 3 bar can thus not explain the increasing injectivity, see figures 8 and 9.

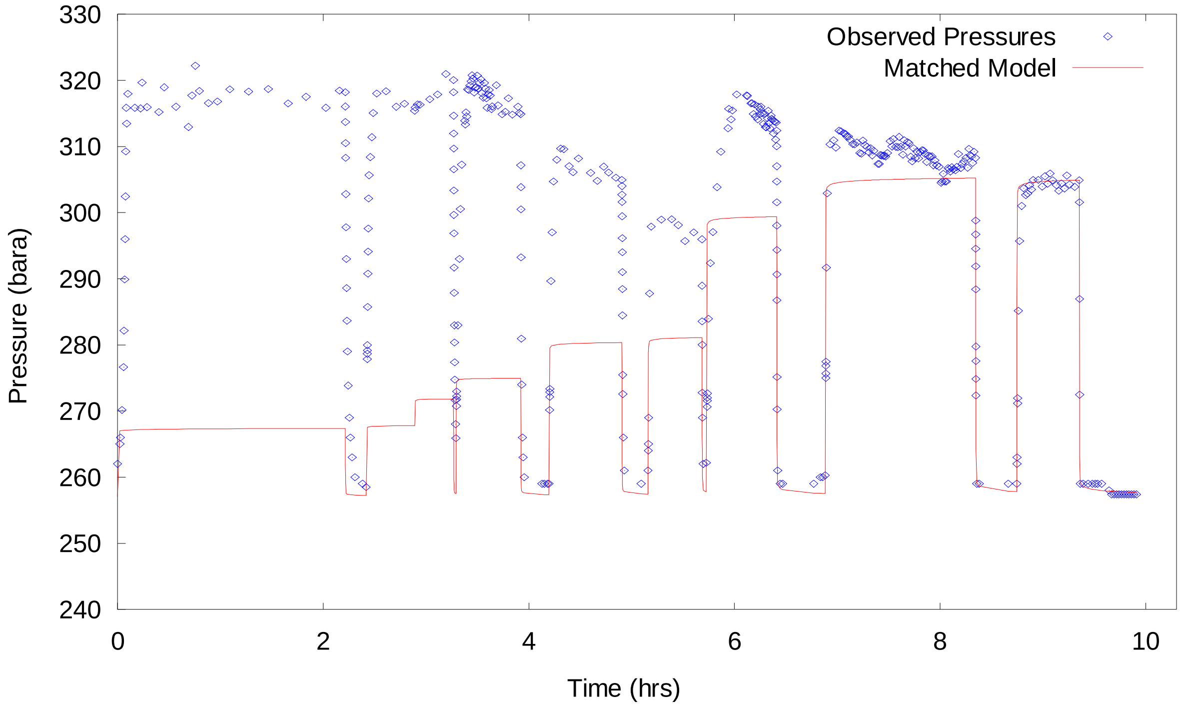
Fig 8 presents the match of the same model as matched on the production test, only matching on skin, wellbore storage and static reservoir pressure (Pi). With the Pi of 245 from the production test the matching was not possible.
The final skin was 58, indicating that most of the screens are still plugged, resulting in an injectivity index (II) of only 5 bar/hr/bar. The matched Pi is 257 bara, 12 bar too high.

Matching the model on the very first injection period, Fig 9, resulted in a skin of 380, an II of only 0.9 m3/hr/bar and again a Pi of 257 bara. With this skin, the model requires of course an incredibly high injection pressure (540 bar) to inject 250 m3/hr.

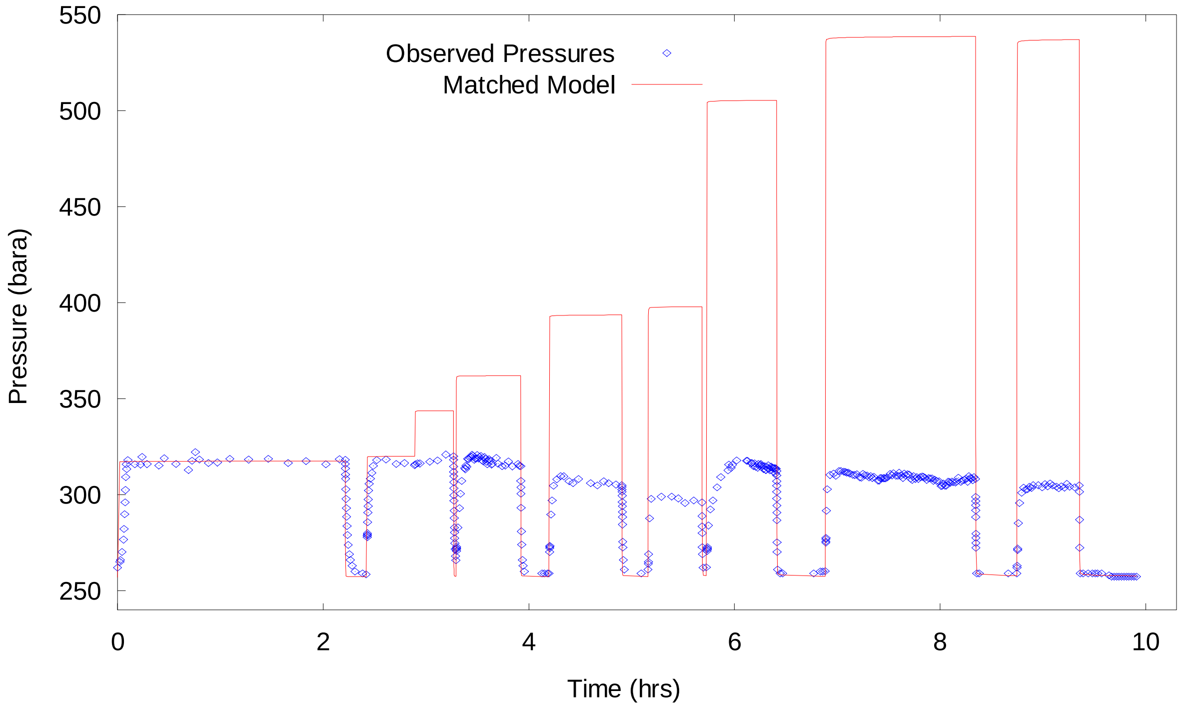
The static reservoir pressure, Pi, should in fact be the same 245 bar as in the production test, but the fall-off pressures were reported positive, while they should have been negative. The Pi of 257 bara is thus 12 bar too high, indicating a free cold water level of some 120 m below surface (93 m calculated for equilibrium water in Chapter 6) while the fall-off pressures were still reported positive. For a better analysis the pressures at >120 m below surface should be measured during an injection test, with also more emphasis on the shut-in (fall-off) periods from which the injected k*h may be derived if not in all layers is being injected.



De Lier GT01 Injection Test Match of last flow-period Fig 8



De Lier GT01 Injection Test Match of first-period Fig 9



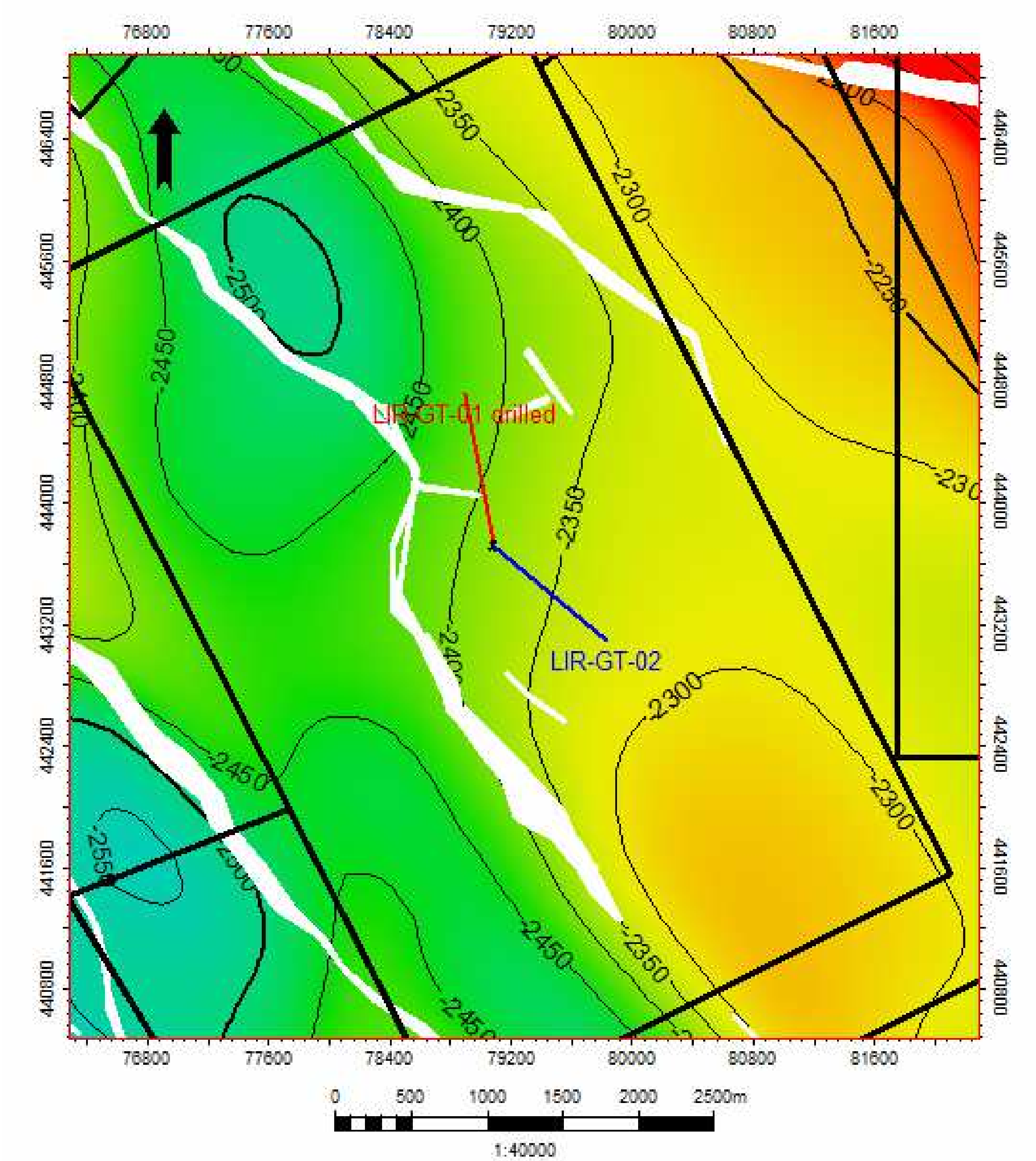


Fig. 10 – Top Structure map with well trajectories of LIR-GT-01 (drilled) and LIR-GT-02 (planned)

9 Well completion scheme

Wellschematic LIR-GT-01 - Final.pdf