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On behalf of

Green Well Westland BV
Van Ockenburghlaan
2675SB Honselersdijk; The Netherlands

PROJECT:

Welltest Honselersdijk GT1

Documentation of well test analysis

Technical report

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1. Summary

The Civilingenieur bureau Dr. Ch. Schmid has adopted from DI K. Gollob on 9th of March, 2012 the data base of the short pumping test (06.03. – 08.03.2012) in the geothermal well Honselersdijk HON GT1 (NL) with the demand to analyse this data.

Based on the detailed requirements and the discussion about our offer for this job, the work was achieved under the designation a second opinion! Therefore, Brunnenservice GmbH with the consultant was also involved in this job.

The hydraulic analyse of this three short well tests give as result a range of transmissibility between 1.25 to $1.47.10^{-3}$ m^2/s. In the time of this first short well test on the submersible pump a maximum temperature from 87.8°C was registered, on the well head 86.1°C.

Due to the different pump rates in all three tests an additional calculated simulation has been made. **This calculation can demonstrate the current productivity would allow a maximum pumping rate from about 60 l/sec.**

2. Input material

The data base for the following hydraulic analyse of this well test was:

- Schlumberger: Testing Services Report, Field: Honselersdijk, Well: GT 01 ST 01, Report Number: 080312, Test Date: März 2012.
- Baker Hughes Centrilift: Completion drawing Greenwell Westland Rev.2, Well: HON GT2, Job Ref.: 43534952 Rev.2, Inst. Date: 05/02/2012.
- Baker Hughes Centrilift: Digitale Daten: *Data 0803 2045.cli*, *events 0803 2042.cli*, *87654321.asc*, *Trending_welltest Greenwell 8 March 2012 18.15 hrs.xls*.
- DrillTec recording files of annular pressure; injection pressure and pump rate for 3 injection periods; First from 9.03.2012 22:00 to 4:00; second 10.03.2012 6:00 -11.30; third 10.03.2012 15:45 -21:15;

According the information from DI K. Gollob and our own short log analyses, the reservoir consists mainly of unconsolidated sandstone section in the depth from 2.360 till 2.900 m TVD. The main sections have been named Delft sandstone section from 2550 m 2720 m MD; an Ablasserdam sandstone section from 2880 m – 3000 m MD and a Pijnacker sandstone section from 3035m – 3155m MD.

3. Data acquisition

3.1 Pressure and temperature on the submersible pump

Pressure (Druck p_{TKP}) and temperature (T_{TKP}) on the submersible pump (Tauchkreiselpumpe TKP resp. ESP) are registered with a down hole sensor provided by Centrilift with a surface read out feature and as a backup a memory gauge has been installed below the motor section of the pump.

Following DI K. Gollob the intake of the ESP was situated in the depth of 775 m and not in the depth from 800 m, corresponding the completion drawing from Centrilift. From this follows that the installation depth of the sensor, positioned under the ESP was from about 789.6 m below surface. The maximum temperature on the ESP from 87.8°C was measured between the third "pumping steps". From the registered pressure on the ESP the water level was calculated in due consideration from the density of the production fluid.

3.2. *Production temperature and well head pressure*

The production temperature (Fördertemperatur $T_{FÖR}$) and the well head pressure (Sonden-Kopfdruck p_{Kopf}) were measured on the well head to be in accordance with the registered parameters TL and PIN as in the testing service report from Schlumberger.

The maximum temperature on the wellhead from 86.1°C was measured between the third pumping steps.

3.3. *Flow rate*

The flow rate Q is equal with the parameter qw_sc in the testing service report from Schlumberger. A reliable conversion from the flow rate to reservoir conditions could not done in this job according the data acquisition situation.

3.4. *Formation pressure (initial)*

The pressure (Druck p_{TKP}) registered on the submersible pump (Tauchkreiselpumpe TKP resp. ESP) can be used in a simplified approach to calculated the reservoir pressure. Unfortunately at the depth of the reservoir a pressure sensor has not installed as this device has failed before being installed (Info K. Gollob).

Therefore the formation pressure must be interpolated from the registered pressure on the ESP. The pressure of the production fluid between the ESP sensor and the depth of the reservoir was calculated in consideration of an equal fluid density distribution in the well. This value was added with the existing (registered) pressure data. Between the ESP sensor and the reservoir a linear temperature – and pressure distribution has been assumed for the current interpretation.

Any variation of the fluid density respectively the variations of the compressibility from the production fluid excite by solved gas was not considered in the following analyses.

The information about the percentage of gas in the production fluid was only available under surface conditions. The ratio was calculated by SLB to be 1,23 m^3 gas/m^3 of fluid.

A detail consideration of the friction losses due to the well bore geometric effects has been neglected at this stage of interpretation. All prediction would have demanded a down hole pressure recording and a pressure recording on top of the production zone during the well test.

The current assumption of a reservoir pressure of 255 bar at top reservoir depth of 2.500 m MD correlates with known gradients in the area (Info K. Gollob).

3.5. Reservoir temperature

For this analysis of this pumping test the maximum temperature registered on the TKP (87.8°C) was defined as the reservoir temperature T_{RES} and is the base of calculation resp. interpolation from the reservoir pressure.

Corresponding logs after the drilling phase have illustrated a temperature maximum of at base Pijnacker of 96°C at 2.900m MD. This would be a temperature gradient of 3.3 °C/ 100 m. Assuming the reservoir has been cooled down during a drilling phase a higher gradient could be justified.

3.6. Water (production fluid) density

The registered densities values and adapt theoretical distribution from the density (by Kestin, Khelifa & Correia, 1981) according the temperature by 1 bar and 84.848 ppm NaCl are plotted in fig.1. This distribution of the density for all further calculations as the reservoir pressure and the water level are taken as the bases.

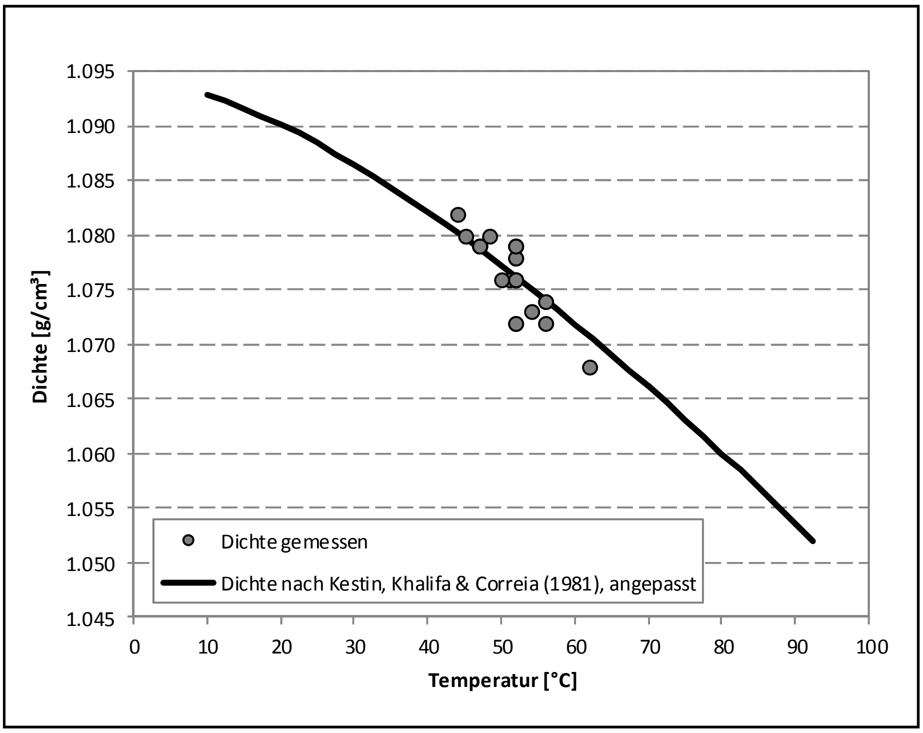


Fig. 1: Measured and adapted density values according Kestin, Khelifa & Correia (1981) with pressure 1 bar and NaCl content of 84.848 ppm.

3.7. Summary of the registered parameters

A choice of the most important parameters is listed in tab. 1. The characteristic of the pumping test executed on the well Honselersdijk GT1 is demonstrated on the graphs 1 – 3 in the attachment.

Table 1: Synoptically table of the well test 1 to 3 on the well Honselersdijk GT1 between 06.03.2012 to 08.03.2012.

Honselersdijk GT1	from	to	Database	
1. well test	06.03.2012 13:41	07.03.2012 07:32	Length of time for the test ($t_{ges)}$:	17,8 h
			Production volume ($V_{Ges)}$:	1.515,3 m^3
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Max. Temperature on the ESP (T_{TKP})	85,4 °C
			Max. fluid Temperature ($T_{För}$):	80,5 °C
			Static water table (p_{TKP}):	81,36 bara at 41,4 °C
			Drawdown in reservoir (dp_{Res}):	4,73 bar at 22,8 l/s
1. built up (recovery)	07.03.2012 07:32	07.03.2012 09:36	Length of time t_{ges}:	2,1 h
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Pressure on the ESP after built up p_{TKP}:	76,14 bara at 76,3 °C
2. well test	07.03.2012 09:36	07.03.2012 22:02	Length of time for the test ($t_{ges)}$:	12,4 h
			Production volume ($V_{Ges)}$:	1.448,3 m^3
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Max. temperature on the ESP (T_{TKP})	87,5 °C
			Max. fluid temperature ($T_{För}$):	84,6 °C
			Static water table (p_{TKP}):	76,14 bara at 76,3 °C
			Drawdown in reservoir (dp_{Res}):	6,91 bar at 29,8 l/s 8,98 bar bat 35,3 l/s
2. built up (recovery)	07.03.2012 22:02	08.03.2012 07:42	Length of time t_{ges}:	9,7 h
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Pressure on the ESP after built up p_{TKP}:	75,89 bara at 63,8 °C
3. well test	08.03.2012 07:42	08.03.2012 17:06	Length of time for the test ($t_{ges)}$:	17,8 h
			Production volume ($V_{Ges)}$:	1.446,8 m^3
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Max. temperature on the ESP (T_{TKP})	87,8 °C
			Max. fluid temperature ($T_{För}$):	86,1 °C
			Static water table (p_{TKP}):	75,89 bara at 63,8 °C
			Drawdown in reservoir (dp_{Res}):	12,26 bar at 43,1 l/s
3. built up (recovery)	08.03.2012 17:06	08.03.2012 20:48	Length of time t_{ges}:	3,7 h
			Depths of the pressure sensor (ESP h_{TKP}):	789,6 m u. GOK
			Pressure on the ESP after built up p_{TKP}:	75,93 bara at 75,2 °C

4. Hydraulic interpretation

4.1. Static water level resp. initial pressure

On the beginning from this well test a static pressure on the ESP from 81,36 bara was registered. This correlate with the interpolated reservoir pressure from 257,35 bara (2.500 m depth). At the well test start up situation a brine with a density of 1.05 has been used to displace the drilling mud (SG 1.25) and to allow the mud breaker to react without future mud invasion.

A cross checks with grow up curve shows that this calculated value is slightly too high and may not reflect the static level of the reservoir. Therefore for all following hydraulic analysis of the well test, a static reservoir pressure from 255,0 bara was assumed for a depth of 2.500 m MD.

It is possible that the observed deviation of the static pressure by the beginning and after the beginning of this well tests might be attribute to an existing contamination of the bore hole wall (filter section) with rest of drilling mud not full broken down by the breaker fluid, or a possible skin effect cause during the first production in this well.

It can be not absolutely be eliminated that this monitored deviation originated from a technical reason, which is currently unknown.

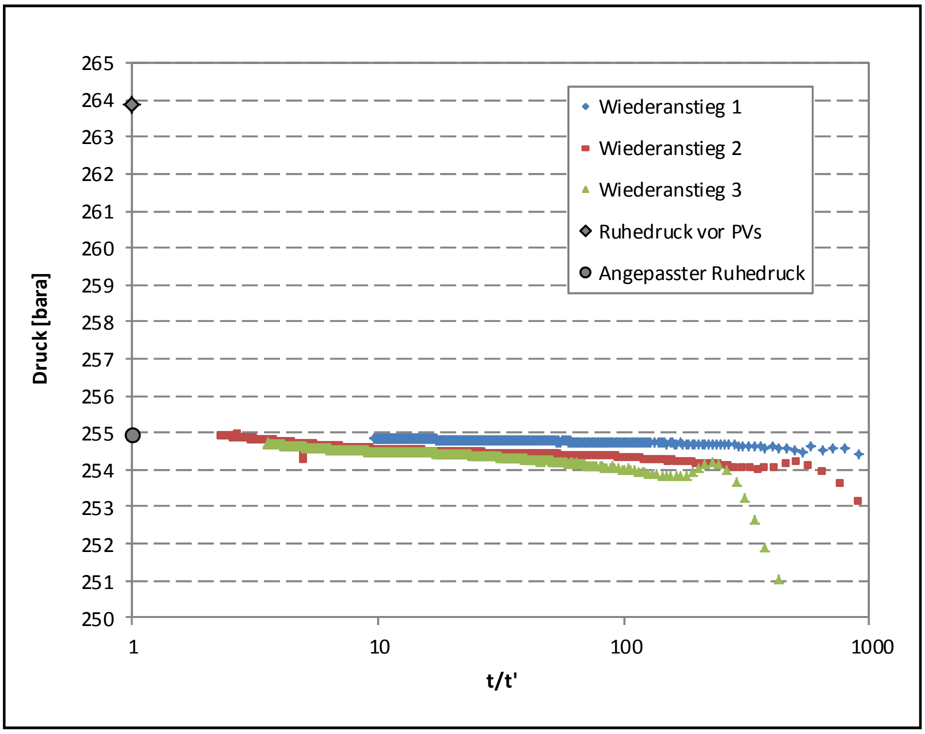


Fig. 2: Semi logarithmic illustration of the built up curve (Horner-Plot) with plotted static level for the beginning of the well test and with the adapted static level

4.2. Stationary interpretation

The Interpretation following Thiem (1906) from selected stationary pumping steps (well test 1 – 3) shows transmissibility between 4.31 to 7.64.10^{-5} m^2/s.

Tab. 2: Results of the stationary calculation (Thiem, 1906) for the well test 1 to 3

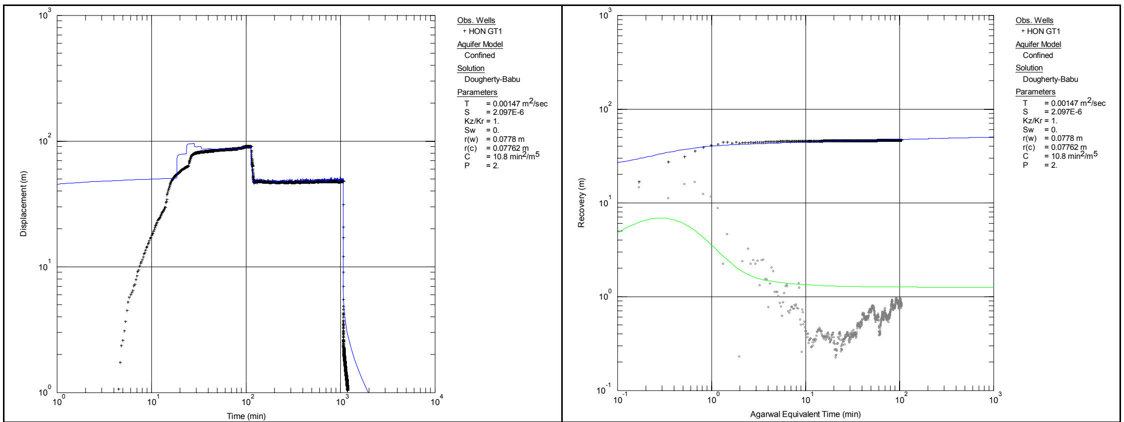
from	to	p_{TKP} [bara]	dp_{Res}* [bar]	Q [l/s]	Kh [m^2/s]	PI [l/s·bar]	comment
07.03.2012 07:02	07.03.2012 07:32	72,02	4,73	22,8	5,91 to 7,64·10^{-4}	4,8	1. Test
07.03.2012 15:20	07.03.2012 16:00	69,90	6,91	29,8	5,29 to 6,84·10^{-4}	4,3	2. Test
07.03.2012 21:32	07.03.2012 22:02	67,89	8,98	35,3	4,82 to 6,23·10^{-4}	3,9	2. Test
08.03.2012 16:37	08.03.2012 17:05	64,67	12,26	43,1	4,31 to 5,57·10^{-4}	3,5	3. Test

*) interpolated results; presumed range of influence for the drawdown cone: 200-2000 m, well diameter : 7,78 cm

4.3. In stationary interpretation

The in stationary interpretation of the well test 1 – 3 Honselersdijk GT1 gives for the reservoir transmissibility Kh from1.25 to 1.47.10^{-3} m^2/s (fig.3, fig.4 and fig.5). The flow resistance in the well resp. the nonlinear loss from the well resistance are calculated resp. interpolated for the in stationary calculation of the well test according a C-Coefficient of 0.0038 bar.s^2/l^2 (=10.8 min^2/m^5)

Well test 1



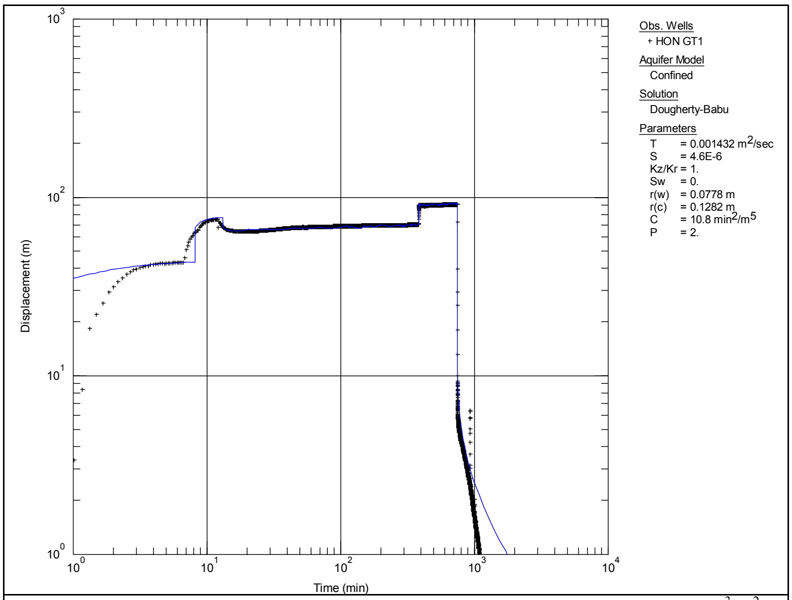
a. Förderphase

b. Wiederanstiegsphase mit Ableitung nach Bourdet et al. (1983)

Kh=1,47·10^{-3} m^2/s

Fig. 3: Diagram to the in stationary calculation (Dougherty-Babu, 1984)

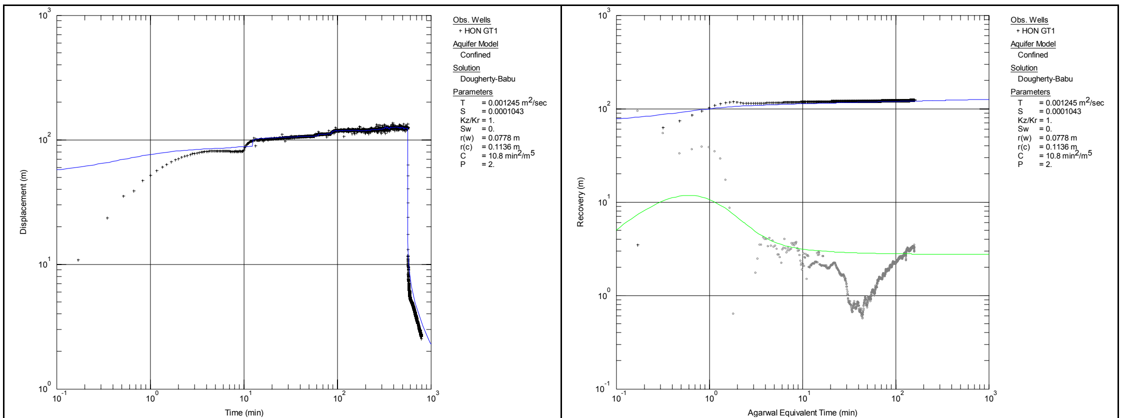
Well test 2



$Kh=1{,}43 \cdot 10^{-3}\ m^2/s$

Fig. 4: Diagram to the in stationary calculation (Dougherty-Babu, 1984)

Well test 3



a. Förderphase

b. Wiederanstiegsphase mit Ableitung nach Bourdet et al. (1983)

$Kh=1{,}25 \cdot 10^{-3}\ m^2/s$

Fig. 5: Diagram to the in stationary calculation (Dougherty-Babu, 1984.

4.4. Interpretation of the productivity

The data acquisition from this well test illustrates that each draw down step after each production rate increase was interrupted with a build-up (recovery) phase.

Therefore for the calculation of the productivity from this well the static draw down pressure values from the test 1 – 3 with production rates between ca. 23 l/s to ca. 43 l/s were used. Following the graphic interpretation in the diagram (fig. 6) the coefficient B (linear well resistance and tube resistance) by Hantush-Bierschenk (1964) was estimated. From this comes the equation:

$$dp_{Res} = 0{,}0038 \cdot Q^2 + 0{,}1196 \cdot Q \text{ [bar·s/l]}$$

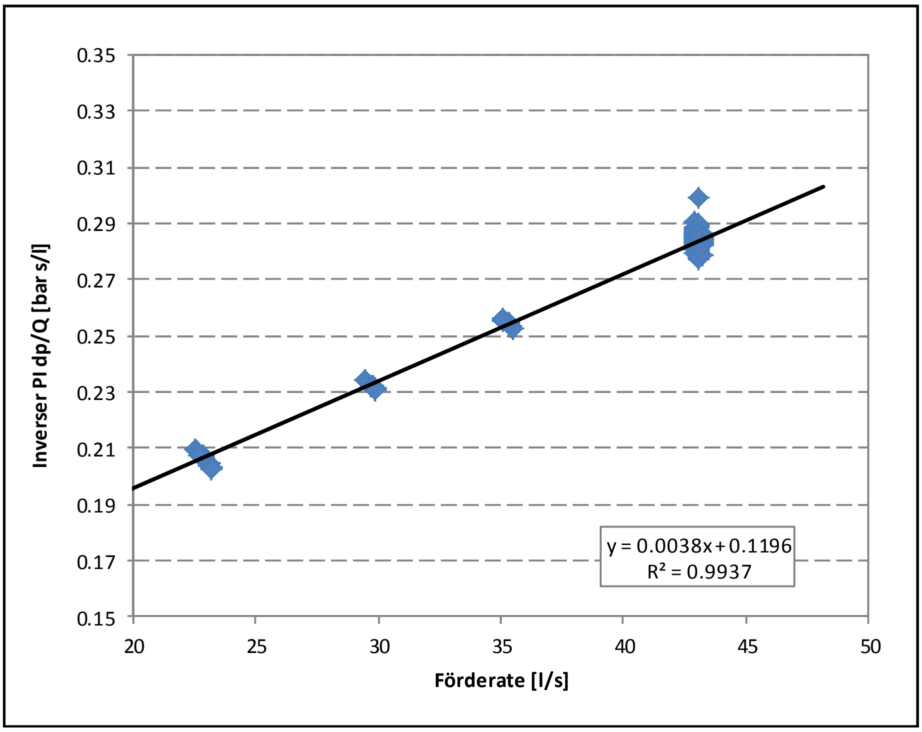


Fig. 6: Diagram of the calculation from the productivity (Hantush-Bierschenk, 1964), Honselersdijk GT1.

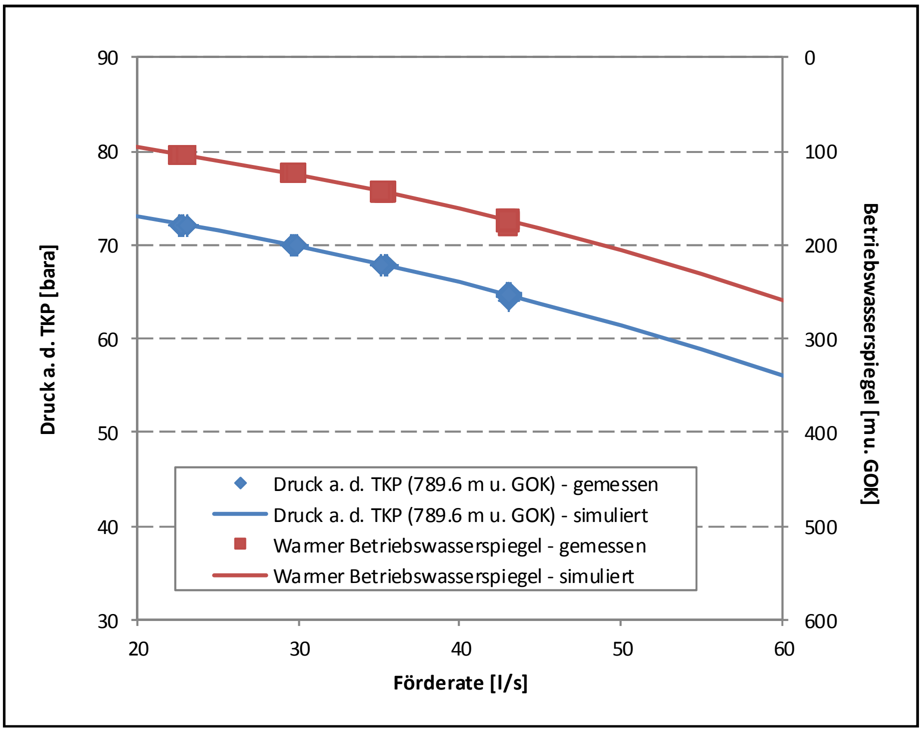


Fig. 7: Simulation of the pressure variation on the ESP (789,6 m) resp. a warm water table under production with the accepted temperature on the ESP from 87,8°C.

For the simulation of the pressure on the ESP for the depth 789.6 m the water pressure in the well between ESP and reservoir as a function of temperature and pressure variation were estimated and from the prognosticated pressure on the top of the reservoir minimized (fig.7). This simulation was done with an isotherm water column between the ESP and the reservoir with the temperature from 87.8°C.

The diagram in fig. 7 shows the water table under production additional. This water table was calculated from the measured resp. simulated pressure on the ESP with the measured and accepted temperature on the ESP.

4.5. Hydraulic characteristic

By the data acquisition by the well test on the well Honselerdijk GT1 the basic pressure (initial reservoir pressure) was not registered. This essential pressure value was registered on the ESP and was interpolated for the further calculation (Chapter 3.4.).

Therefore an interpretation resp. prediction about the hydraulic character of the reservoir in detail (skin effect, connection to the aquifer system, distance to sealing fractures or pinch outs) is currently not possible due to missing data sets.

For any future long term well test the acquisition conditions must be adapted to the expected results!

5. Compilation of these well test results

The following table and figures shows a summary from all until now calculated and interpreted hydraulic thermal parameters.

Tab- 3: Compilation of the hydraulic parameters in the well Honselersdijk GT1.

Well test	Transmissibility Kh $[m^2/s]$		PI [l/s·bar]	Production temperature [°C]
1. Test (ESP)	Stationary:	$5{,}91$ to $7{,}64 \cdot 10^{-4}$	4,8	85,4 (ESP) 80,5 (Well head)
	In stationary:	$1{,}47 \cdot 10^{-3}$		
2. Test (ESP)	Stationary:	$4{,}82$ to $6{,}84 \cdot 10^{-4}$	3,9 bis 4,3	87,5 (ESP) 84,6 (Well head)
	In stationary:	$1{,}43 \cdot 10^{-3}$		
3. Test (ESP)	Stationary:	$4{,}31$ to $5{,}57 \cdot 10^{-4}$	3,5	87,8 (ESP) 86,1 (Well head)
	In stationary:	$1{,}25 \cdot 10^{-3}$		
- Calculated with interpolated data.				

Transmissibility

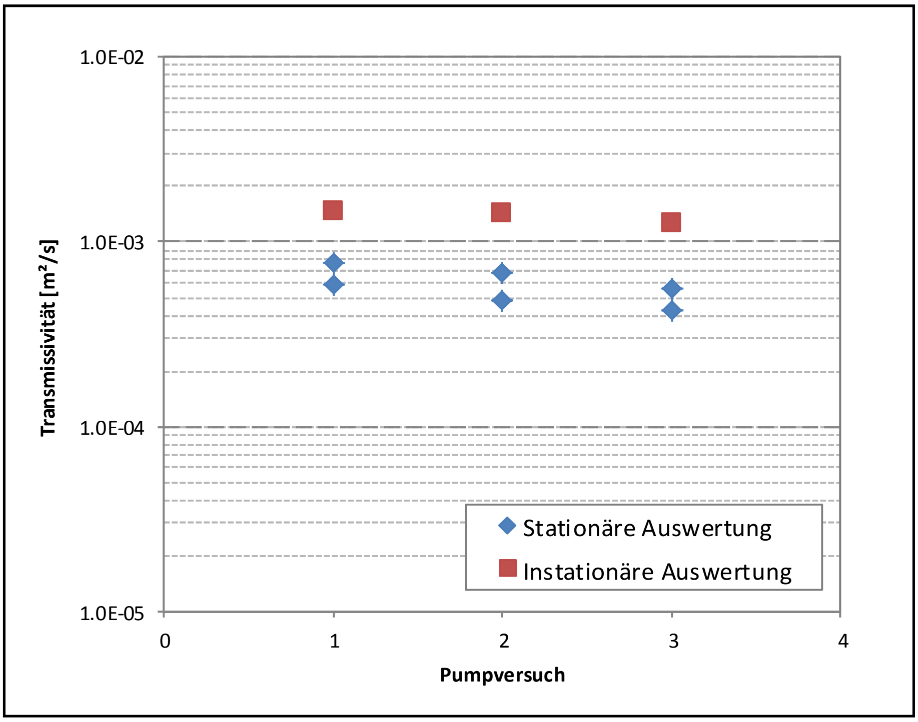


Fig. 8: Graphic of the transmissibility from the well Honselersdijk GT1.

Max. Temperature

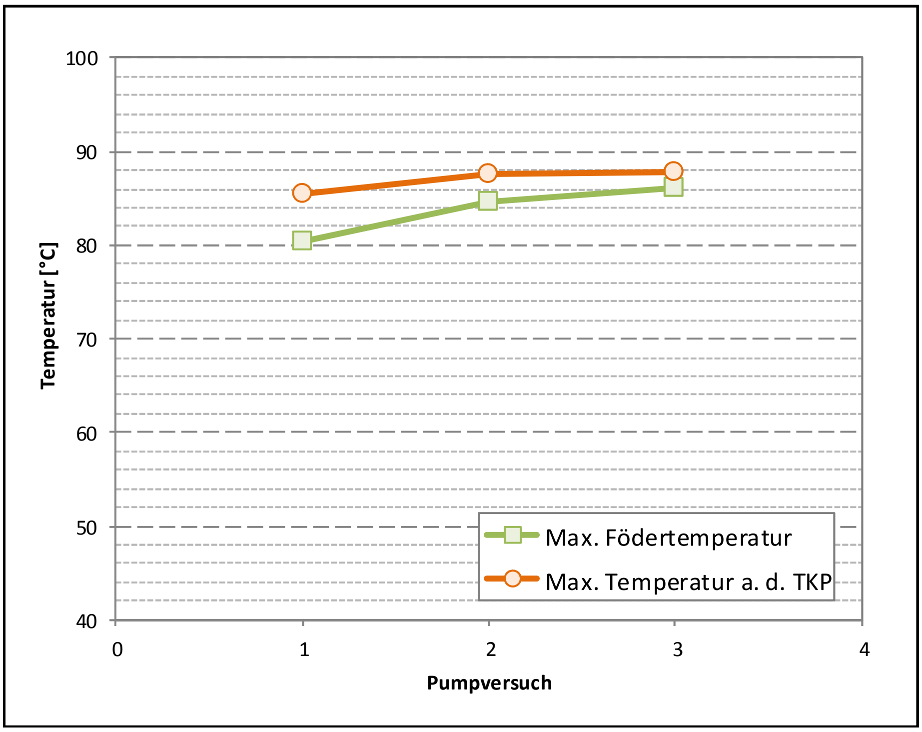
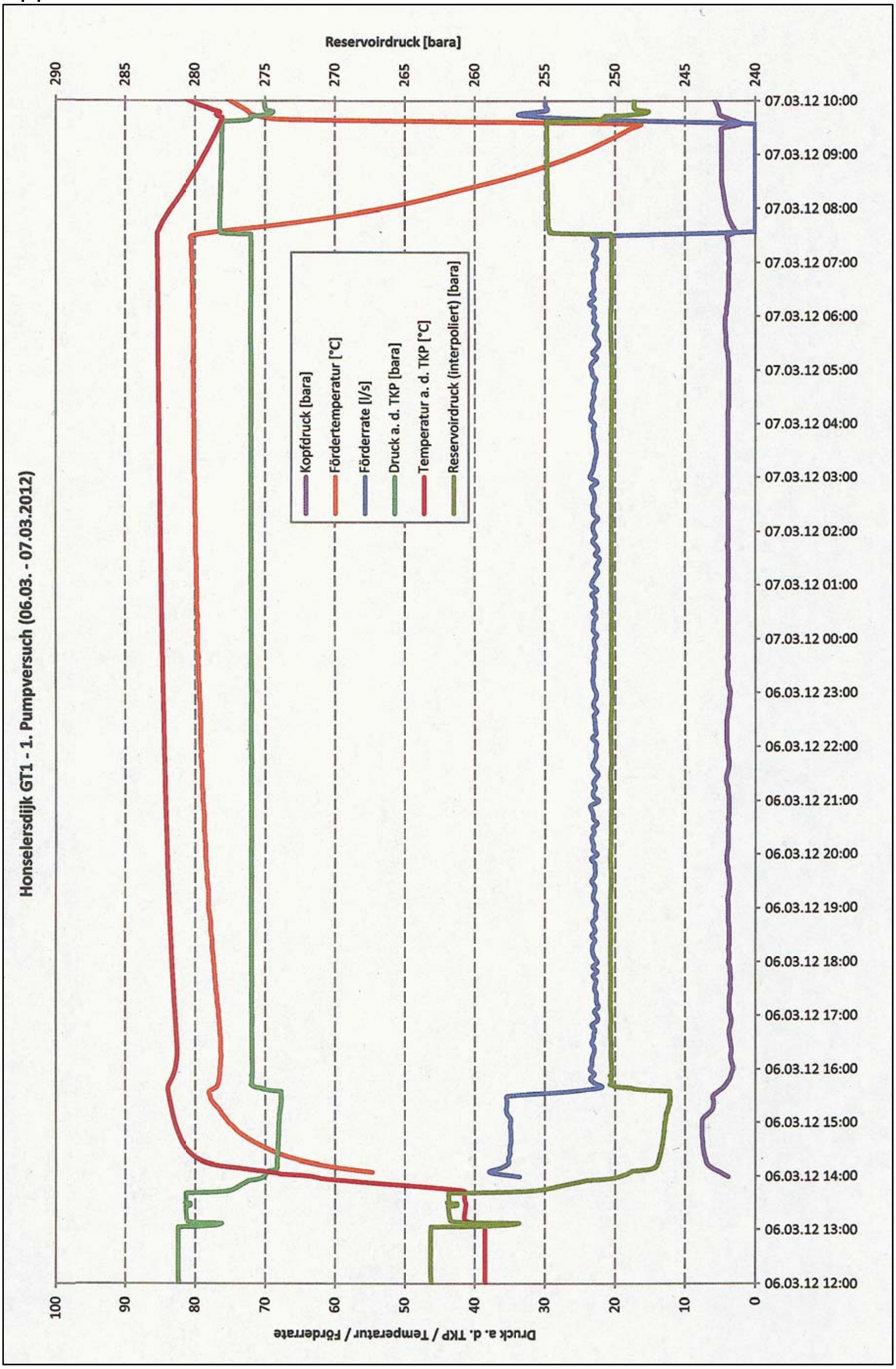


Fig. 9: Graphic of the max. Temperature under production on the well Honselersdijk GT1

Appendix 1:


Honselersdijk GT1 - 1. Pumpversuch (06.03. - 07.03.2012)
Reservoirdruck [bara]
290
285
280
275
270
265
260
255
250
245
240
Druck a. d. TKP / Temperatur / Förderrate
100
90
80
70
60
50
40
30
20
10
0
Kopfdruck [bara]
Fördertemperatur [°C]
Förderrate [l/s]
Druck a. d. TKP [bara]
Temperatur a. d. TKP [°C]
Reservoirdruck (interpoliert) [bara]
07.03.12 10:00
07.03.12 09:00
07.03.12 08:00
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07.03.12 06:00
07.03.12 05:00
07.03.12 04:00
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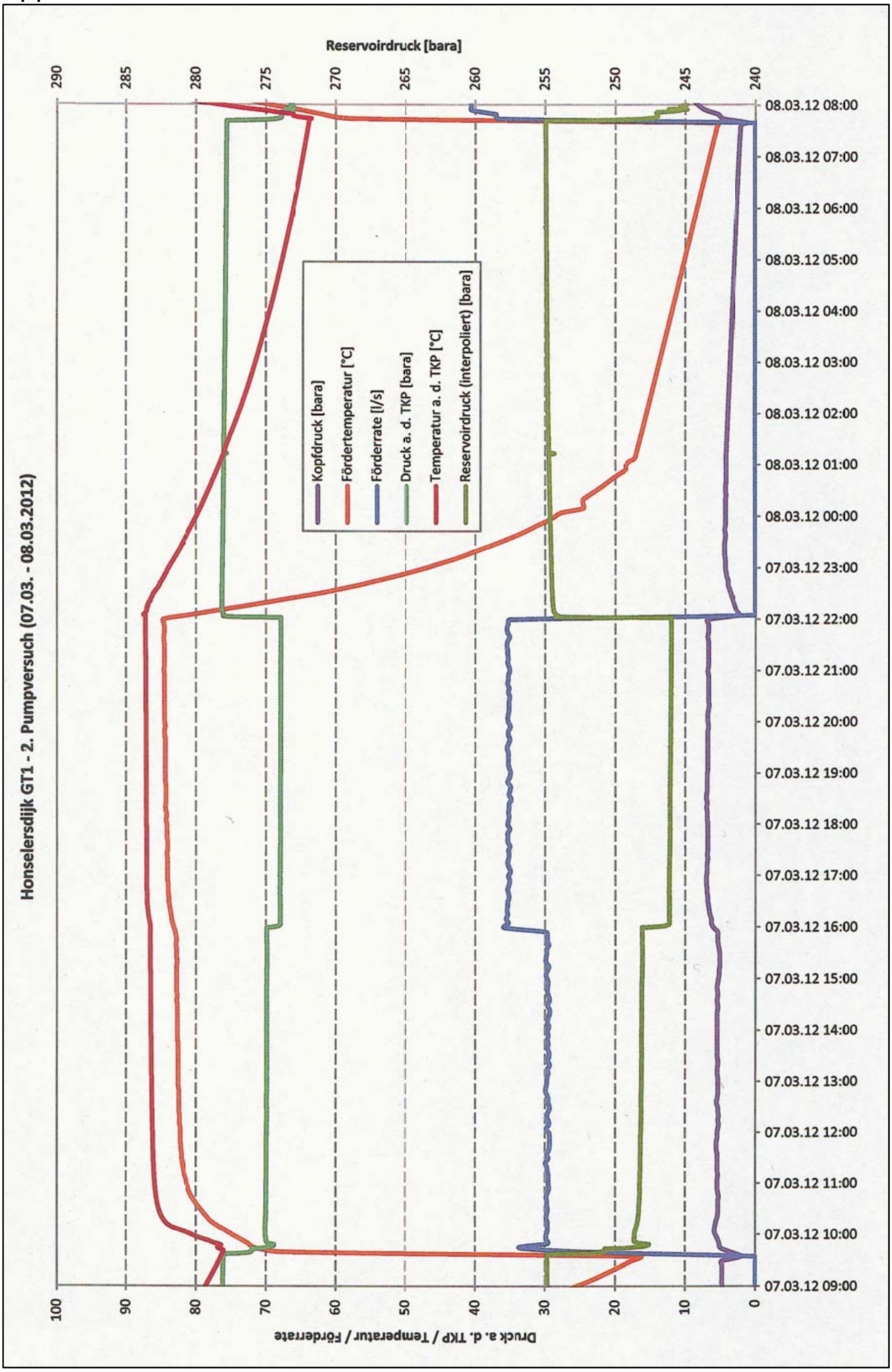
Appendix 2:


Honselersdijk GT1 - 2. Pumpversuch (07.03. - 08.03.2012)
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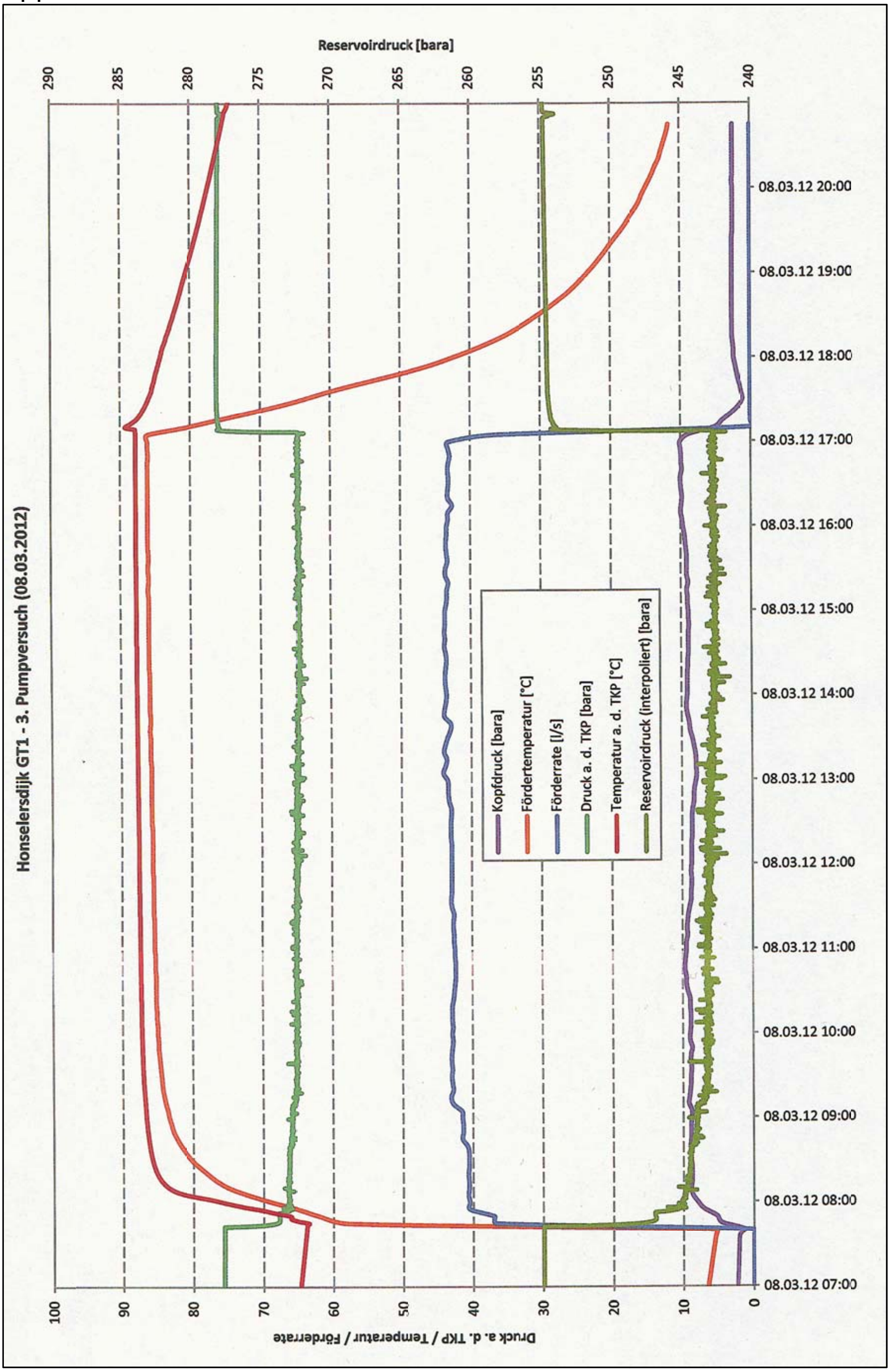
Druck a. d. TKP / Temperatur / Förderrate
Kopfdruck [bara]
Fördertemperatur [°C]
Förderrate [l/s]
Druck a. d. TKP [bara]
Temperatur a. d. TKP [°C]
Reservoirdruck (interpoliert) [bara]

Appendix 3:


Honselersdijk GT1 - 3. Pumpversuch (08.03.2012)
Reservoirdruck [bara]
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260
255
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240
Druck a. d. TKP / Temperatur / Förderrate
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Kopfdruck [bara]
Fördertemperatur [°C]
Förderrate [l/s]
Druck a. d. TKP [bara]
Temperatur a. d. TKP [°C]
Reservoirdruck (interpoliert) [bara]

Appendix 4: Notes to the assigned Log Interpretation HON_GT-01

Used documents:

- Plot HON_GT-01
- Plot Masterlog_HON_GT1_115_3240mTD
- Remarks considering QL log interpretation Honselersdijk. January 27 th 2012 (Berend Vrouwe , Robbert Rutten)

In general we fully agree with the presented log interpretation, based on standard interpretation techniques and rules!

a) Plotted Logs are of good quality.

b) GR was used for sand - shale separation; additionally SP is used. The upper part (Delft formation) represents a sandy formation relatively homogeneous; the lower Part (Pijnacker Formation) represents alternating shale – sand sequence. A detailed description is given as follows: "In contrast with the Delft sandstone (interval 2562 – 2620 m) that appears as a rather massive package of 58 m thickness, the Pijnacker sand strata mostly appear as individual 3- 10 m thick sand beds enclosed in shale. Most sand beds show a marked upwards fining on GR and have an abrupt base, indicating their depositional origin as multiple channel events."

c) The SP shows some specific deflection: Sand goes to positive, shale goes to negative. This is typical for Rmf< Rw. The log header shows a very low Rmf = 0.02 Ohmm at BHT 96°C and confirms this situation.

d) Resistivity separation clearly indicate permeable zones at sand indications from GR. Originated by the fluid resistivity's Rmf< Rw the measured resistivity's show Rxo < Rt (or Ro). There are no Resistivity indications for significant hydrocarbon.

e) With respect to porosity is reported: "Delft reservoir is confirmed by … sonic derived total porosity PHIT =17 %) … for the Upper Pijnacker (interval 2633 to 2736) this value is 17 %. Lower Pijnacker interval 3070 to 3170 m PHIT is 12 %." - Density derived porosities confirm this range.

f) Additionally about permeability an estimate could be derived from the plot Masterlog_HON_GT1_115_3240mTD. It shows for some depth points with chemical analysis also permeability.

   - For the section 2570 … 2612 m (measured depth) four permeability's are reported: 2570 md, 2586.5 md, 2590 md, and 2612 md. The low variation again confirms the homogeneity of Delft sand formation and gives an average of 2590 md. The sand represents about 80 % of this section of screen 4 – therefore an averaged permeability of about 2000 … 2100 md results.

- If the grain size distribution of the Lower Pijnacke Formation is comparable to Delft Formation the lower porosity would result in permeability for the sand layers in the order of 1000 md and is still high. In the report QL log interpretation Honselersdijk. January 27 th 2012 (Berend Vrouwe , Robbert Rutten) is noted " The Pijnacker sandstone Member, dominated by individual beds with porosities ranging from 14 – 19% has a two-fold division. There is an upper more sandy part just below the Delft sandstone, interval 2633 to 2737 m, and a lower interval 2890 -3210m separated by a shale dominated zone 2737 - 2890." Assuming for the interval 2633 to 2737 m (screen 3) an averaged sand content of 30% for this part of the formation permeability of about 300 md would result. Because the sand content of the zones of screens 1 and 2 is less (about 15 … 20 %) here the averaged formation permeability is in the order of 150 … 200 md.

From log results the Delft Formation clearly has the better reservoir properties mainly based on homogeneity. The Pijnacke Formation is an alternating sand-shale formation. Sand layers are cumulative also of reasonable reservoir quality.

Appendix 5: Injection test

After the well test three short injection tests was done on the well Honselersdijk GT1. Data sets from the "mud pressure" (pump pressure), "pressure on the choke manifold" (annulus pressure) and the "injection rate" was produced over the testing time. Furthermore screen shots from these three test intervals were also available (Fig. 1-3). The data sets are represented as Excel files how only test one and two could be handed by the Excel software. For as detailed processing of these data sets background information's like the well situation and fluid parameters will be necessary. In general the tests have been done only for a short period therefore no comprehensible stable flow conditions have been reached.

Injection test 1 (Fig. 1) was done from 09.03.2012 at 22:10 to 10.03.2012 at 04:05. The injection rate was approximately 20 l/sec (1.200 l/min).

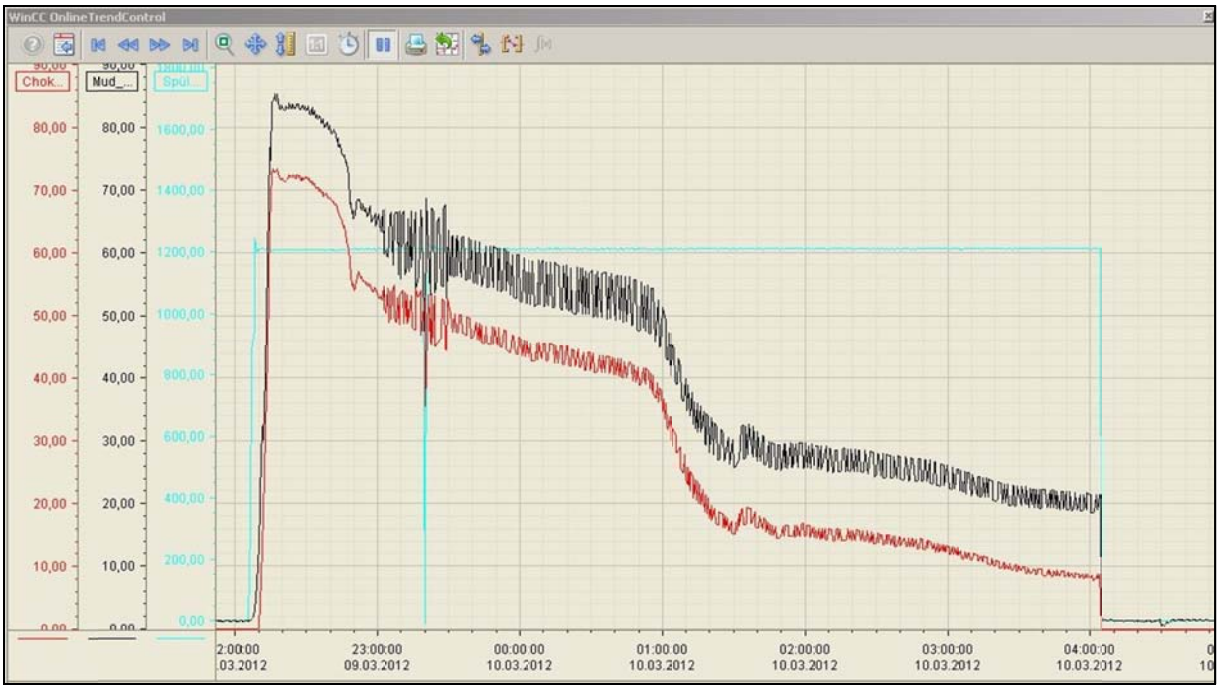

Fig. 1: Injection test 1 Honselersdijk GT1

The screen shot shows a typical curve progression at the beginning of a fluid injection in a reservoir with an extremely abrupt increase of the initiation pressure until to the breakdown pressure (wellbore pressure) of approx. 73 bar (85 bar mud pressure). A significant decrease at 40 bar (52 bar mud pressure) could be the beginning of the frictional pressure drop. According to this the following flat part of the curve could represent the "pore pressure" at 16 to 8 bar (28 to 20 bar mud pressure).

Injection test 2 (Fig. 2) was done from 10.03.2012 at 05:30 to 10.03.2012 at 11:30. The injection rate was approximately 30 l/sec (1.800 l/min). This data set gives in spite of a higher injection rate a complete different picture compared to figure 1. One reason therefore could be the opening of the reservoir by the first test step with much higher pressure.

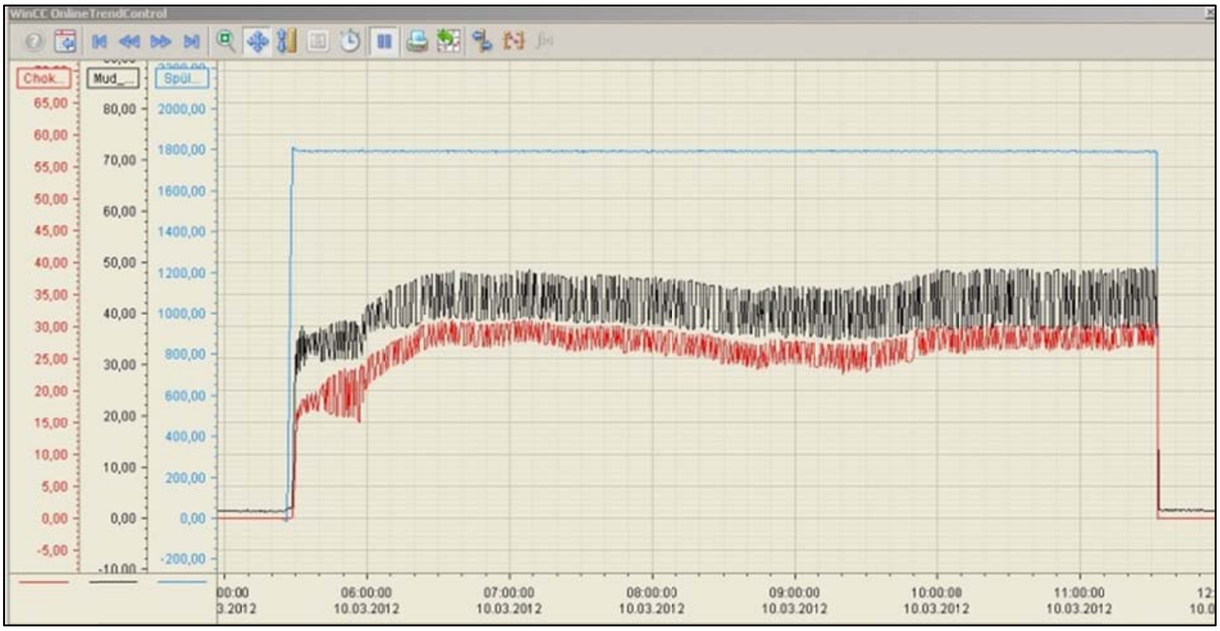

Fig. 2: Injection test 2 Honselersdijk GT1

The screen shot shows a flat curve progression at the beginning. The typical breakdown pressure (wellbore pressure) could not be noticed. The maximum wellbore pressure reaches a maximum value of approx. 28 bar (44 bar mud pressure). After this point the pressure drops marginal to a minimum value of approx. 25 bar (40 bar mud pressure). After this pressure minimum a slight increase up to the end of the test is detectable. For a detailed analysis of this curve a long term injection test will be necessary when the second well is available for these tests. For a comprehensive analysis more injection steps (Guidelines for produced water injection) must be done. In this case a monitoring of the test will be possible.

It should be noted that the registered data shows a fluctuation from about 4 bar for the wellbore pressure and quite 10 bar for the mud pressure!

Injection test 3 (Fig. 3) was done from 10.03.2012 at 15:20 to 10.03.2012 at 18:20 and after a short break from 10.03.2012 at 20:25 to 21:20. The injection rate was planned and started at approximately 45 l/sec (2.700 l/min), but has to be reduced later on to a level of approximately 28 l/sec (1.650 l/min).

This test is not readable in the transmitted Excel format and also the existing screen shot can´t be seriously interpreted.

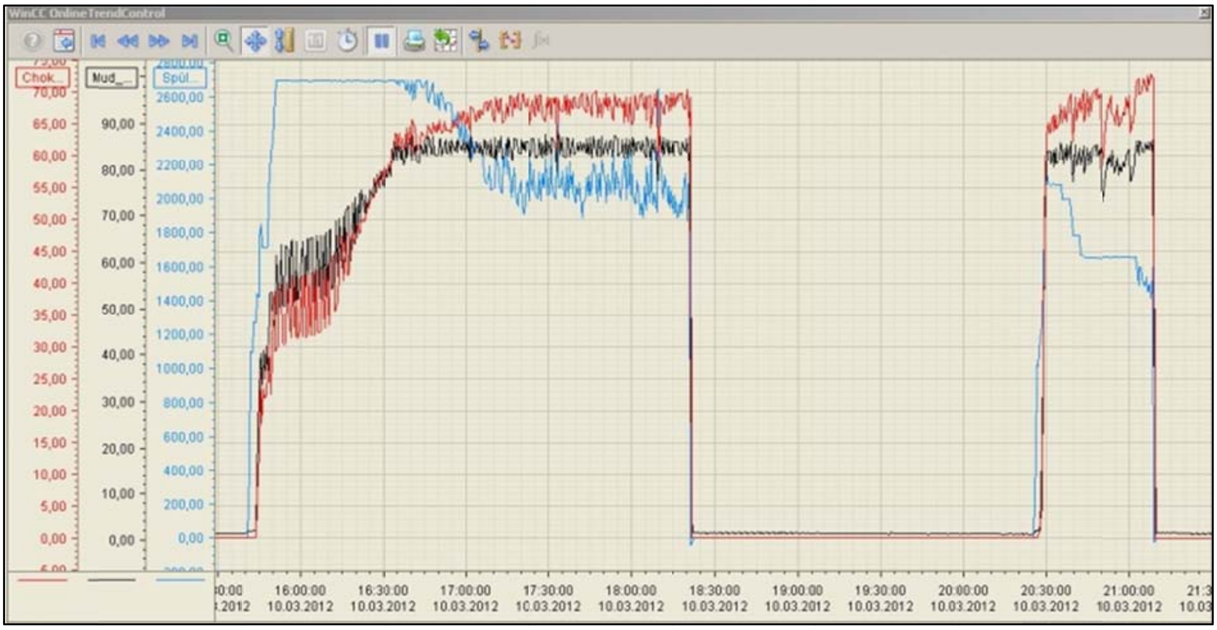

Fig. 3: Injection test 3 Honselersdijk GT1

Including the first remarks from K. Gollob to the test results it looks like that an economic based injection with a flow rate in minimum 30 l/sec is realistic. However an economical long term injection will be influenced by multiple facts like water quality, rock water interaction, pore geometry etc. We agree with the given remarks by K. Gollob “What we have seen so fare on both tests (production & injection) the well bore geometric creates quite a significante power demand to overcome the friction pressures. The short screen section dominates this factor.”