Analysis of Welltest HAG-GT-02

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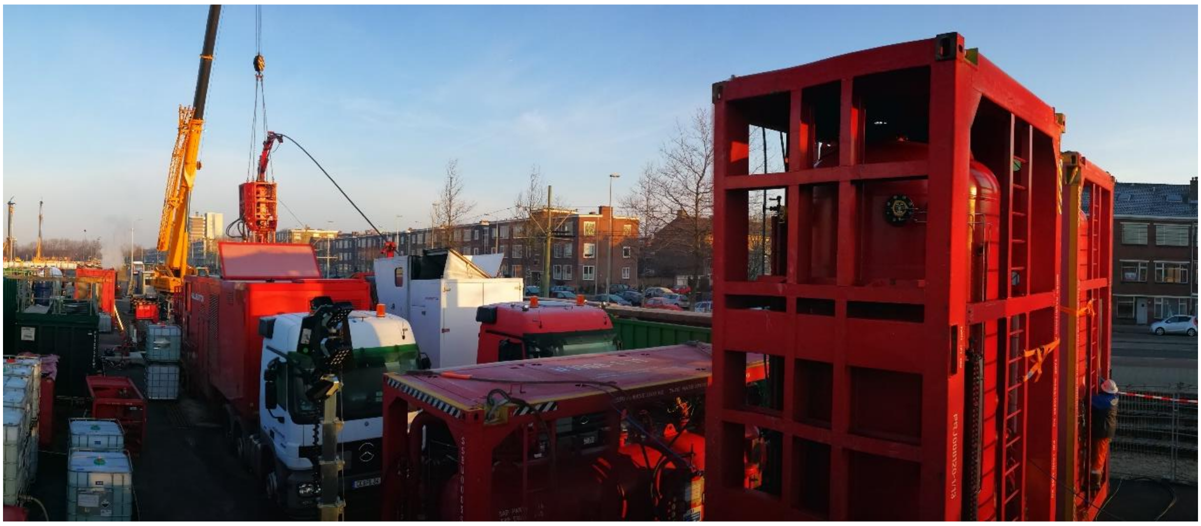

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1 Summary

Well HAG-GT-01 was production tested from 22 to 24/02/2018 by a multi-rate test, followed by a shut-in period of 12 hours. The production rates, generated by Nitrogen injection in a coiled tubing, varied between 19 and 106 m3/hr. Cumulative water produced was about 1680 m^3.

Following are the main conclusions:

- The data quality of the test was high and made it possible to derive clear conclusions.
- Average reservoir permeability is about 1400 mD assuming that the whole net sand of 96 m contributes to flow.
- A flow barrier at 770 m was required for an optimum model match.
- Static reservoir pressure at 1782m tvdTDB is 180.5 bara
- Reservoir temperature is about 73 ºC.
- Transient flow capacity (PI) after 54 hours flow is 34.4 m3/hr/bar.
- Skin varies from 7.15 at 105.9 m3/hr to 1.62 at 19.8 m3/hr. This indicates a damage skin of only 0.6, with most flow resistance caused by friction in the liner and screens.

2 Well test results

Parameters test interpretation	Value	Dimension
Name of well	HAG-GT-02	n.a.
Coordinates of well (X, Y)	E (m) = 78215.39 m	N (m)= 452494.28 m
Top aquifer	2138	m (AHTDB[1])
	1761	m (TVDTDB)
Nett thickness Aquifer	96	m (TV)
N/G aquifer	86	%
Average Porosity Aquifer	20	%
Salinity formation water	120	g/l NaCl
Expected max temperature formation[2]	73	^{0}C
Diameter wellbore	6.0	Inch
Depth coil nozzle	2100	m (AHTDB)
	1732	m (TVDTDB)
Location gauge	2100	m (AHTDB)
	1732	m (TVDTDB)

Table 1 Parameters for well interpretation

Flow sequences well test	Skin @ gauge	Final flow-rate, m3/hr
Flow 1	1.62	19
Flow 2	5.59	83
Flow 3	4.76	59.5
Flow 4	5.78	89.5
Flow 5	7.15	105.9

Table 2 Flow sequences for well interpretation

Parameter	Value	Dimension
Permeability thickness ($k \cdot h$)	134.4	Dm (Darcy-meter)
Assumed net thickness (h)	96	m
Permeability (k_h)	1400	mD
Reservoir damage skin (S)	0.6[3]	dimensionless
Skin at 105.9 m3/hr	7.15	dimensionless
Skin at 19 m3/hr	1.62	dimensionless
Flow barrier at	770	m
Productivity Index (P.I.) (48hrs)	34.4[4]	m^3/hr/bar

Table 3 Results test interpretation and analysis

[1] TDB = Tie-down bolts
[2] This temperature is seen as average formation temperature
[3] Extrapolated to zero rate in order to remove friction effects.
[4] PI @ gauge level (@top liner hanger). True reservoir PI will be higher.

3 Introduction

Well HAG-GT-02 was stimulated by means of a two stage 5% HCl clean-out. After the acid was produced out, the well was production tested from 22 to 24/02/2018 by a multi-rate test, followed by a shut-in period of 12 hours. The liquid production rates, generated by N2 injection through a coiled tubing, varied between 19 and 106 m3/hr. Cumulative water produced was about 1680 m^3.

The pressure and temperature data were recorded by two high-accuracy gauges just 2 m below the gas exit of the coiled tubing, at 1732 m TVDTDB
The well was produced from the Delft sandstone (SLDND) reservoir. This is covered by screens from a depth of 1773 to 1870 TVDTDB.

In spite of the short distance between the deep gauge at 1732 m TVDTDB and top reservoir at 1761 m TVDTDB, the bottom gauge has been corrected for the cooling of a 50 m water column, using the formula established in an offset geothermal-well project, which has nearly the same salinity and temperature.

4 Reservoir and Rate data

The water salinity of 120 g/l at 73 °C corresponds with a water viscosity of 0.492 mPa·s and C_w of 4.9 x10^{-10} Pa^{-1} (3.4x10^{-6} psi^{-1}). The total C_t has been set to 8.7 x10^{-10} Pa^{-1} (6 x10^{-6} psi^{-1}).
The reservoir porosity was set to 20% in view of the good permeability.
The wellbore radius R_w has been set to the bit size of 6", or 7.5cm.
In view of the deviation of the well with an average angle of about 49 degrees through the reservoir, the wellbore radius was adjusted to $R_w \cdot \sqrt{\frac{1}{2} \cdot (1 + (\cos\alpha)^{-2})}$ = 10cm (0.32 ft), for the analysis with a vertical well model.

The porosity and total compressibility (C_w + C_f) may have to be changed after the interference test with the next well.

The next table lists the used rate sequence during the production test.

Delta time, hours	Flow Rate, m3/hr
25.2	19
3.9	57.6
3.1	82.8
0.4	6.5
3.4	59.9
1.8	87.8
1.2	77.0
1.3	89.5
1.4	104.7
12	0

5 Correction for water column cooling

The pressures of the downhole gauge were extrapolated 50m to top reservoir using the offset project correction formula:

$\Delta P = CDC*L*[1063 + 0.45*\Delta T - 0.005*\Delta T^2]$, With ΔP the pressure correction, CDC a constant [CDC= 9.8063×10^5 if pressure in bar and L in meters], L the vertical depth difference between deep gauge and top reservoir and ΔT the difference between the maximum (73 °C) and current gauge temperature in ºC.

This correction was not really necessary, as the top gauge was not so corrected but gave practically the same analysis results.

6 Pressure recordings

Figure 1 shows the original downhole gauge data. The rates have been divided by 6000 and 68.1 was added in order to plot them on the right-hand temperature axis.

This figure shows the main problem with the analysis as the rates, after the initial low flow, vary continuously. For the permeability this does not matter much, but the skin values are less accurate then preferable.

The large pressure increase at the start of the test is caused by the early start of the gas-lift while running the coiled tubing deeper. The production during this running-in has been taken into account, the pressures obviously not.

The effect of the gas lift on the early build-up can be seen on the gauge temperature (and of course on the analysis plots): the T drops the first 2.6 hrs, slightly increase then, followed by a more gentle decline about 5 hours after CI. The gas bubbles upwards after CI, expanding and pushing colder water downwards, also increasing the gauge pressure above the current reservoir pressure at the wellbore. The model matching should thus be carried out only on the build-up pressures after this 5 hours.

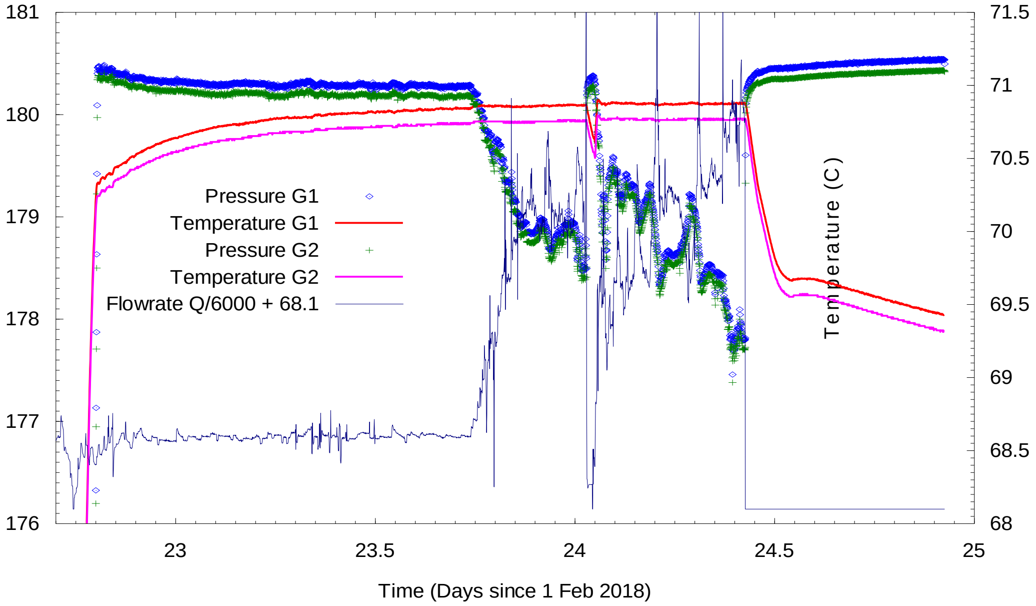

Figure 1 Downhole Pressure/Temperature & Flowrate well test HAG-GT-0

7 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 wellbore effects, caused by the rising gas bubbles after close-inn.

8 Analysis of pressure data

The downhole gauge pressures have been matched with a finite homogeneous model.
The average reservoir permeability is 1400 mD, and the skin at the final, maximum, rate is 7.2 (matching on the final flowing point before the build-up). The wellbore storage coefficient is 178 $m^3 \cdot Pa^{-1}$ (0.163 bbl/psi). The static reservoir pressure at the top reservoir of 1782m TVDTDB is 180.5 bara. The transient productivity (at 53 hrs) is 34.4 m3/hr/bar.

A single flow barrier at 770 m had to be used for a good model match. This distance assumes that the whole sand thickness contributes to flow and is in vertical communication. For a lower thickness, the permeability is higher and the distance larger. Also, such an observed flow barrier does not have to be fully sealing.

The radius of investigation was determined by placing a second flow barrier at an increasing distance: This second barrier had to be more than 2100 m away in order not to affect the model match.

Figure 2 presents the match of the main build-up, both the Horner "straight" line (dark blue) as its derivative (green). Note that the first 4-5 hours are above the model line, caused by the rising gas bubbles. The late build-up can be matched very well, both in the Horner plot as in its derivative.
Note that this derivative had to be smoothed. This reduces the cloud of derivative points to a line, but the large noise on the data causes some oscillations. But note that after the wellbore storage effect, the derivative is much better, showing clearly the effect of the flow barrier (otherwise it should have been horizontal).
NB: The (Agarwal) effective time is used in order to obtain a straight-line Horner plot for this test with a short and varying rate history and a relatively long build-up. The total build-up time in this figure is 12 hrs, with a final effective time of only 4.65.

Figure 3 presents the analysis plot of the top gauge at gauge depth. The results are practically identical to those of the corrected deeper gauge.

The match of all pressure data is presented in Figure 4 for the model matched on the final flowing pressure, and for the match on the last pressure of the long initial rate of 19 m3/hr. It is clear that the first model matches only the high rate periods, as its skin is 7.15, while the skin of the second model is a low 1.62, matching indeed only the very first flowrate.

Note the clear effect of the gas-lift bubbles during the early build-up on the right-hand zoomed-in scale (purple points).

This increase in skin with increasing flow rate is caused by friction in the vertical flow conduit between reservoir and gauge. The real, rate independent, damage skin has been obtained by plotting the skin values at the various rates in Figure 5, which shows this damage skin to be less than 1.

NB: If the wellbore radius is assumed to be the outer radius of the screens, the effective R_w is only 8.14cm (0.267 ft). Applying this R_w, the skin factor at the highest rate reduces to 6.725, and at the lowest rate to 1.096. This results in a damage skin at zero rate of -0.13.

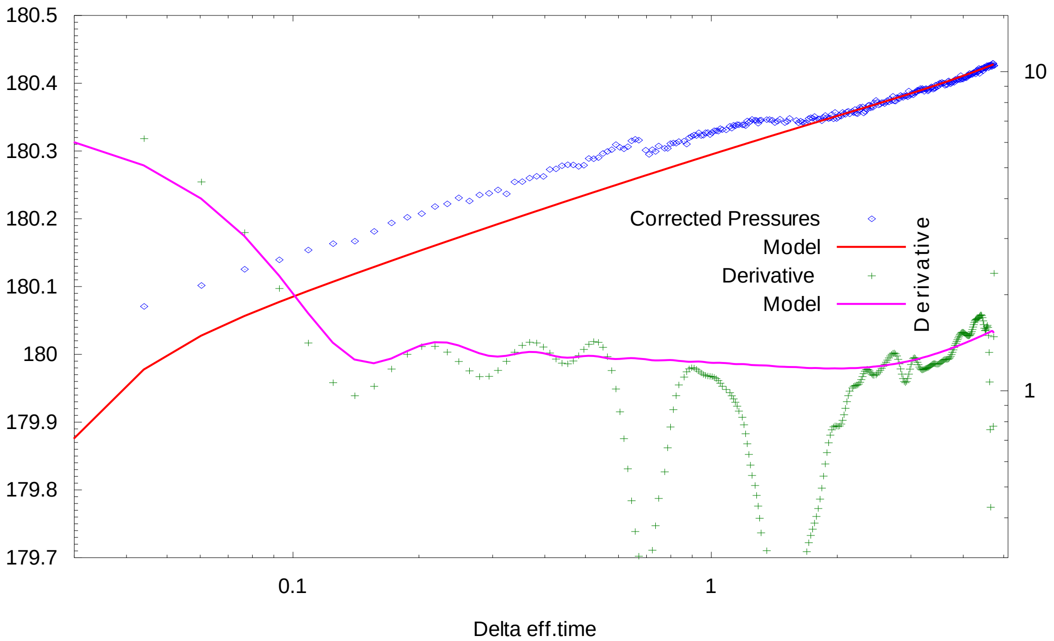

Figure 2 HAG-GT-02, Horner Plot & Derivative, Main Build-up, Bottom Gauge

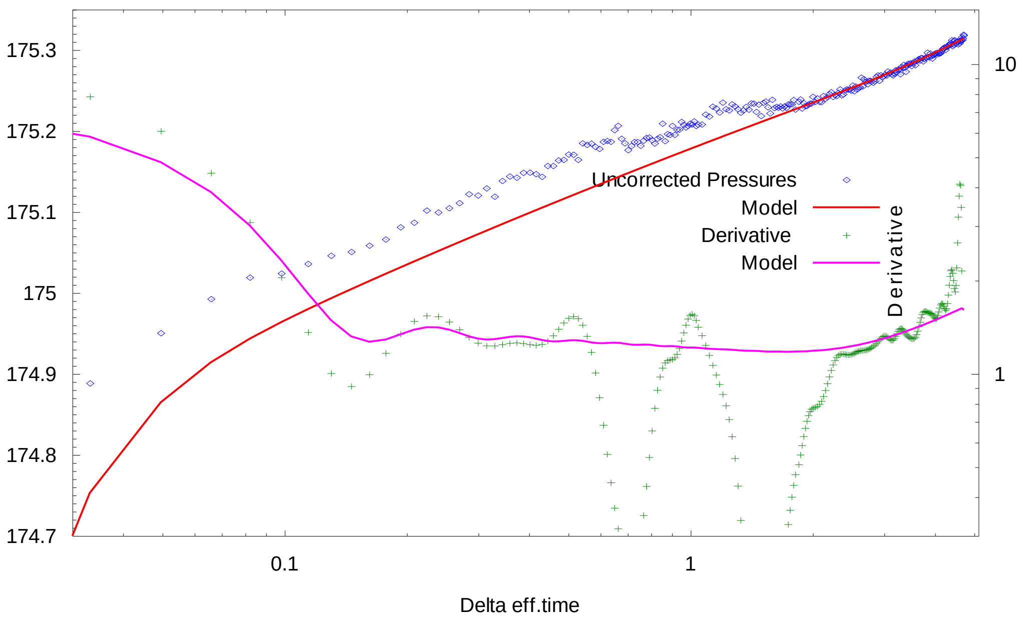

Figure 3 HAG-GT-02, Horner Plot & Derivative, Main Build-up, Top Gauge

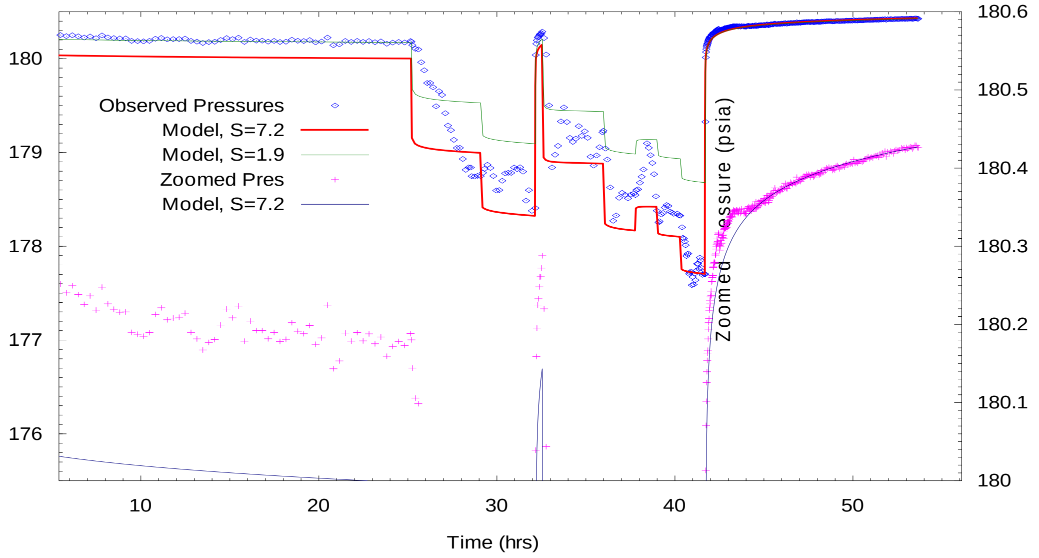

Figure 4 HAG-GT-02, History & Zoomed Build-ups

Rate dependency of skin factor is probably due to friction in the 4.5" section. The rate-skin Figure 5 has been matched with a Darcy-Weisenbach based friction model in Figure 6, using an absolute pipe roughness of 0.3 mm and a total conduit length of 49 m blind pipe plus 148 m of screens. In order to obtain the shown match of the observed skin values, the complex (vertical flow plus inflow) resistance over the screens required an effective screen length of 4x148 m (K-factor of 4). As can be seen a good correlation is reached with this type of model. This friction model with roughness and K-factor can act as base for further production modelling.

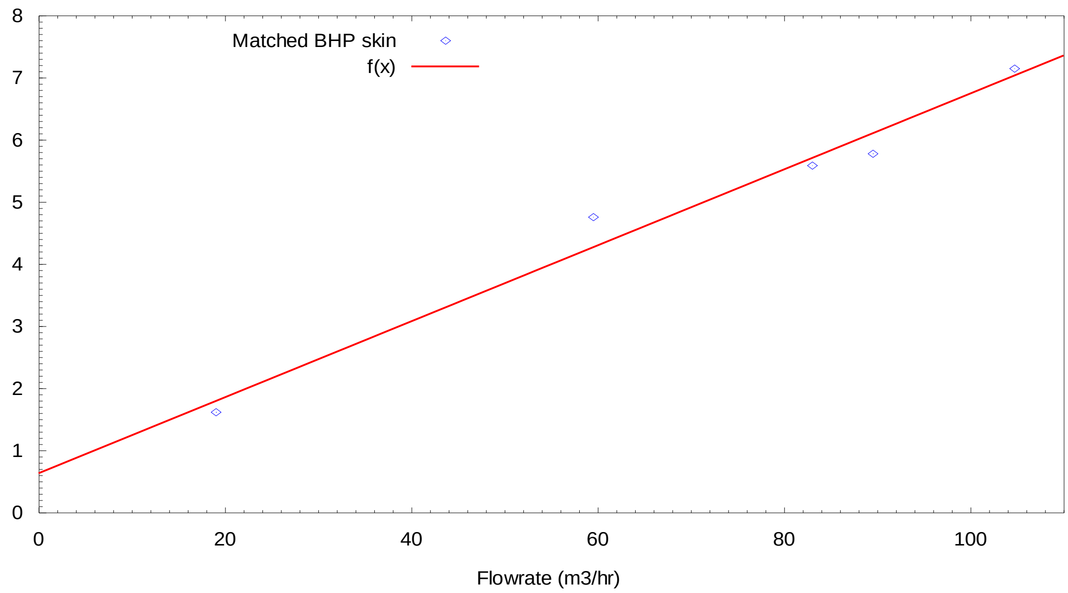

Figure 5 HAG-GT-02, Skin Factor versus Flowrate. Derived from Pressure Transient Analysis

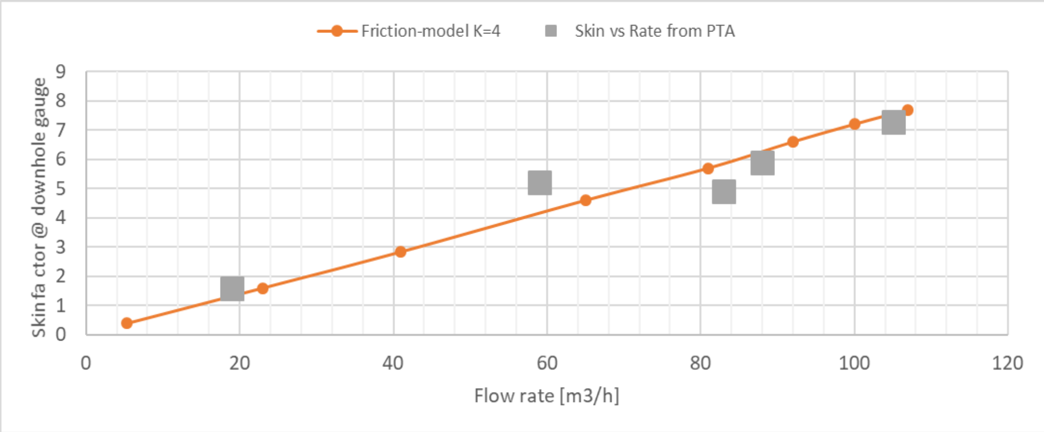

Figure 6 Flow rate vs skin – Pressure transient model matched with friction model.

9 Recommendations & Lessons Learned

In order to improve on the analysis of the second well, it is advised to increase the number of data points of the gauges to 4/minute. This should result in a better averaging of the data points.

The build-up is on the short side due to the long wellbore storage effects, although that has not hindred this analysis. If a better information about nearby flow barriers is required, it is recommended to extend the BU to 24 hours.
Try also to maintain at least 4 different flowrates for longer times at a constant N2 injection rate and choke size.