# Analysis of Welltest HAG-GT-01

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## Contents

# 1 Summary

Well HAG-GT-01 was production tested from 18 to 20/03/2018 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 15 and 130 m3/hr. Cumulative water produced was about 1870 $m^3$. During the production of the spent acid of run 1 on 15 and 16 march, a total of 206 m3 was produced.

Following are the main conclusions:

- The data quality of the build-up was good and made it possible to derive clear conclusions.
- Average reservoir permeability is about 2300 mD assuming that the whole net sand of 62.5 m contributes to flow.
- Static reservoir pressure at 2150 m tvdTDB is 218.5 bara.
- Reservoir temperature is about 80 ºC.
- Transient flow capacity (PI) after 113 hours flow is 21 m3/hr/bar.
- A flow barrier at about 1400 m is possible.
- Skin is high at 20, caused by the limited open interval of only 36 % of the total k*h.
- It is likely that the lower part of the well is blocked. A rough inflow model shows a match when the part below 2244mTVDBRT does not contribute to flow.
- The shut-off layers are still in vertical communication (Spherical flow) at a vertical permeability of 12 mD.
- Wellbore storage coefficient is low at 0.16 b/psi, reducing a further factor 2.5 due to the compression of the nitrogen in the top of the well.
- Wellbore effects disturb part of the build-up but do not hinder the detailed analysis.

# 2 Test results

| Parameters test interpretation | Value | Dimension |
|---|---|---|
| Name of well | HAG-GT-01 | n.a. |
| Coordinates of well (X, Y) | E (m) = 78210.96 m | N (m)= 452500.55 m |
| Top aquifer | 2545 | m (AHTDB[1]) |
| | 2195 | m (TVDTDB) |
| Nett thickness Aquifer | 62.5 | m (TV) |
| N/G aquifer | 73 | % |
| Average Porosity Aquifer | 20 | % |
| Salinity formation water | 120 | g/l NaCl |
| Expected max temperature formation[2] | 80 | ºC |
| **Diameter wellbore** | 8.0 | Inch |
| | | |
| **Depth coil nozzle** | 2490 | m (AHTDB) |
| | 2150 | m (TVDTDB) |
| **Location gauge** | 2490 | m (AHTDB) |
| | 2150 | m (TVDTDB) |

*Table 1 Parameters for well interpretation*

| **Parameter** | **Value** | **Dimension** |
|---|---|---|
| Permeability thickness ($k{\cdot}h$) | 145 | Dm (Darcy-meter) |
| Assumed net thickness ($h$) | 62.5 | m |
| Permeability ($k_h$) | 2300 | mD |
| Reservoir damage skin factor ($S$)[3] | 20 | dimensionless |
| Open interval | 36 | % of total kh |
| Skin factor at 91 m3/hr[4] | 2.5 | dimensionless |
| Possible Flow barrier at | *1400* | m |
| Productivity Index (P.I.) (113 hrs) | 21 | $m^3$/hr/bar |

*Table 2 Results test interpretation and analysis*

[1] TDB = Tie-down bolts
[2] This temperature is seen as average formation temperature
[3] For 91m3/h and for the full interval (62.5m)
[4] Skin factor of open interval (~36% of kh)

# 3 Introduction

In February and March 2018 the wells HAG-GT-01 and 02 have been stimulated to remove the formation damage. After stimulation both wells have been tested. This document describes the analysis of the HAG-GT-01 test. The HAG-GT-02 test and corresponding interference test have been described in separate documents.

Well HAG-GT-01 was stimulated by means of a two stage 5% HCl clean-out. After the acid was produced out, the well was production tested from 18 to 20/03/2018 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 15 and 130 m3/hr. Cumulative water produced was about 1870 $m^3$, plus the 206 m3 during clean-up.

The pressure and temperature data were recorded by two high-accuracy gauges just 2 m below the gas exit of the coiled tubing, at 2490 m AHDTDB (2150 m TVDTDB).
The well was produced from the Delft sandstone (SLDND) reservoir. This is covered by screens from a depth of 2183 to 2290 TVDTDB.

# 4 Reservoir and Rate data

The Gamma-ray shows a total of 87 mah net sand of the total 125 m of reservoir. From the deviation ratio of 87/120 follows a net thickness of 62.5 m (205 ft).
The water salinity of 120 g/l at 80 °C corresponds with a water viscosity of 0.482 mPa·s and $C_w$ of 4.9 x$10^{-10}$ $Pa^{-1}$ (3.4x$10^{-6}$ $psi^{-1}$). The total $C_t$ has been set to 8.7 x$10^{-10}$ $Pa^{-1}$ (6 x$10^{-6}$ $psi^{-1}$).
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 5-7/8", or 7.5 cm.
In view of the deviation of the well with an average angle of about 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 next table lists the used rate sequence during the production test.

| Delta time, hours | Flow Rate, m3/hr |
|---|---|
| 34 | 6.06 |
| 55 | 0 |
| 22.45 | 15.45 |
| 5.25 | 27.4 |
| 8.48 | 64.9 |
| 7.81 | 81.3 |
| 2.07 | 91.45 |
| 11.85 | 0 |

*Table 3 **Flow sequences** for well interpretation*

# 5 Pressure recordings

Figure 1 Shows the original downhole data of both gauges.

This figure shows the main problem with the analysis as the rates vary continuously. For the permeability this does not matter much, but the early skin values are not well defined.

The pre-test production during clean-up of about 206 m3 has been included in the analysis, but did not make a difference.

Figure 2 presents the build-up pressures in more detail. About 2.6 hours after close-in (CI), the gauge temperature increases and the pressure decreases about 0.03 bar during 0.6 hour, returning to the normal trend thereafter.
In order to have better insight into this phenomenon, the tubing-head pressure (THP) has been included: The THP starts to decline due to cooling at the same time that the pressure decline reverses. This indicates that the fast increase in THP after CI pushes colder water downwards, increasing the recorded pressure. At time 20.2, the gauges are too cold for the time and depth. As soon as the THP stops increasing and starts to decline, hot water moves up, causing a lower BHP and an increase in Temperature, both following the normal build-up trend thereafter.
This mechanism is also the cause of the rather low wellbore storage.

How this phenomenon could affect the analysis was determined by comparison with the earlier test of HAG-02, in which the same pressure drop during the build-up was observed.
That pressure dip occurred some 3 hours after CI. As the build-up derivative in that well showed the same constant value (after wellbore storage) before and after this dip, in line with the matched low skin, and thus without any spherical flow, the observed spherical flow in this well is no artefact of the physical process causing this dip. It can be concluded that this dip did not influence the analysis results of this test, as long as the model was matched separately on the early and on the late build-up, with the reservoir pressure as only difference.

Note that the small shrinkage of the coiled tubing, 0.01 bar, just before the 0.03 bar drop, has been corrected for the top gauge in Figure-2; as this was done together with filtering, the spread of the data points is reduced, the purple points. Such correction could also have been made for the 0.03 bar pressure drop, but that would have resulted in a gap of the data.

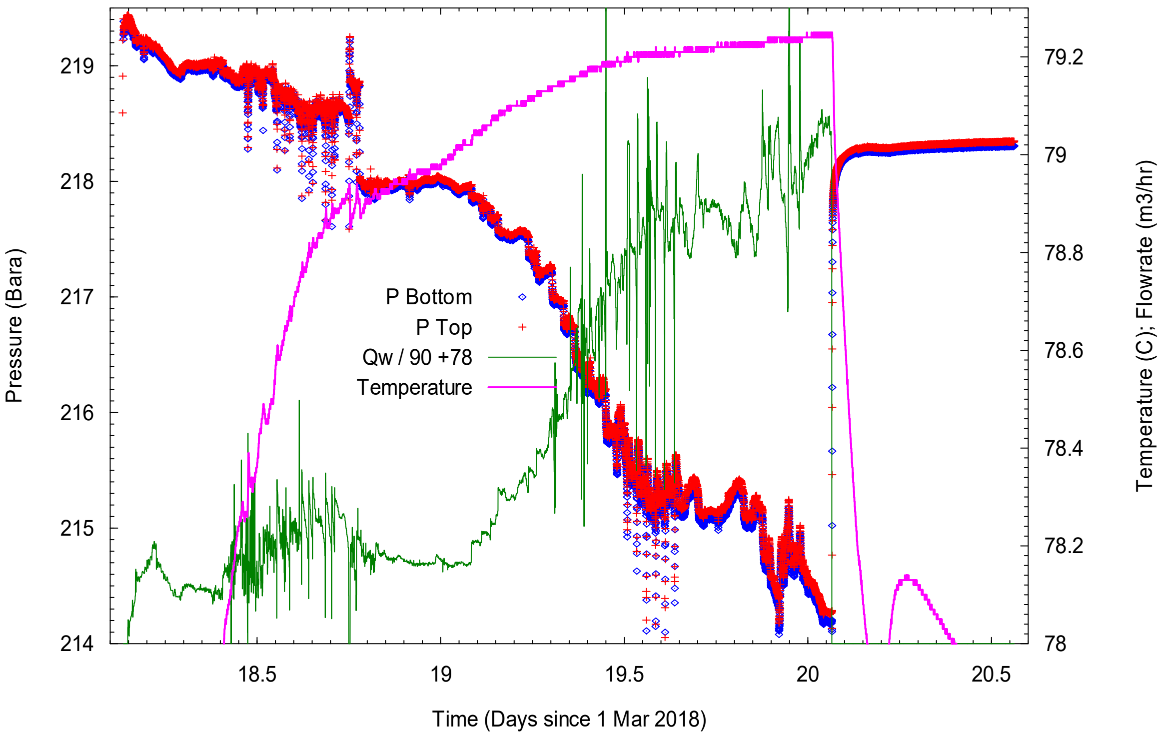


*Figure 1 Pressures, Temperatures & Flowrates of well test HAG-GT-01*

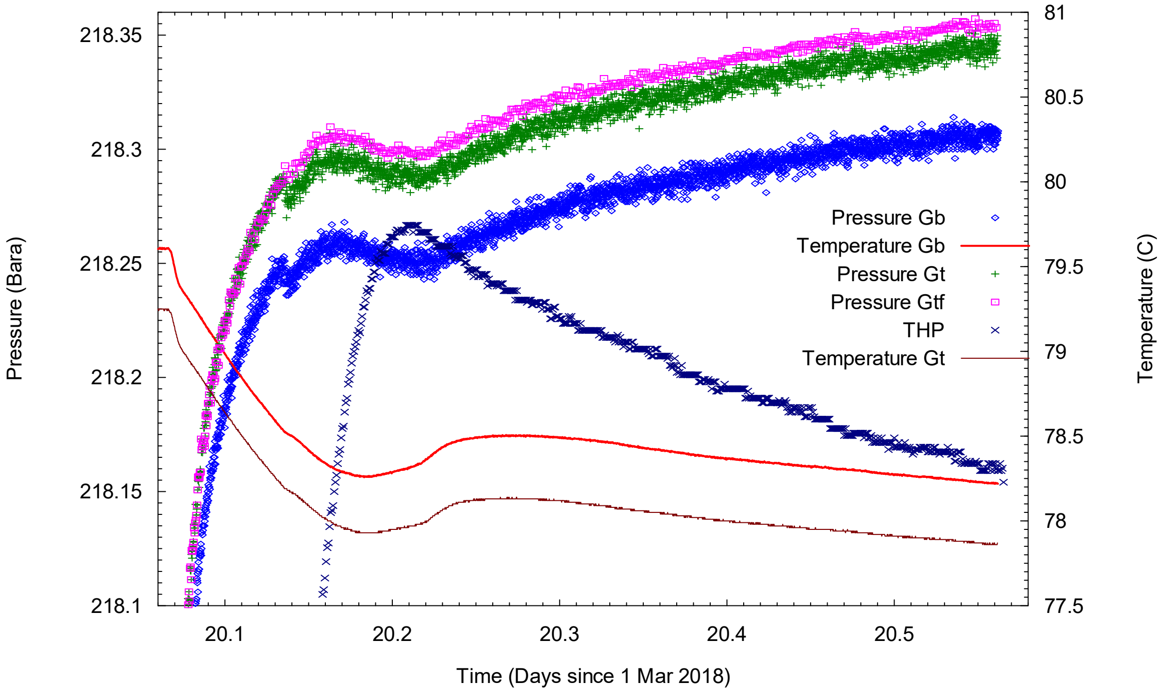


*Figure 2 Build-up Pressures, Temperatures & THP of well test HAG-GT-01*

# 6 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.

# 7 Analysis of pressure data

The downhole gauge pressures have been matched with a finite homogeneous model with a limited entry interval (Partial-Penetration or in short: *PP*, or Spherical-Flow model) and with a fully open model. The latter has been matched mainly on the final 7 hours of the build-up, establishing the radial permeability at 2300 mD (assuming of course that the full 62.5 m net sand contributes).
As the model requires a skin of 20 to match the final flowing pressure, and as the signature of the wellbore storage derivative indicates spherical flow, the PP model has been matched on the early BU data.
This excellent model match did not only result in the open interval of 36 % of the total k*h, or only 22.6 m if the reservoir is homogeneous, but also its skin of 2.5 and its position at the very upper or lower end of the reservoir interval. The plugged 40 m (in fact 64% of k*h) is still contributing to flow via a low vertical permeability of 12 mD.

The skin is low with respect to the rate-dependent skin observed in HAG-02 (~7) at a similar flowrate, suggesting that the flow comes from the top of the reservoir, with the shortest vertical flow section.
NB: the presented model match could only be obtained when it was matched on the skin of the open interval. An earlier try used a fixed skin of 6, thought to be the rate-dependent value at the last flowrate.

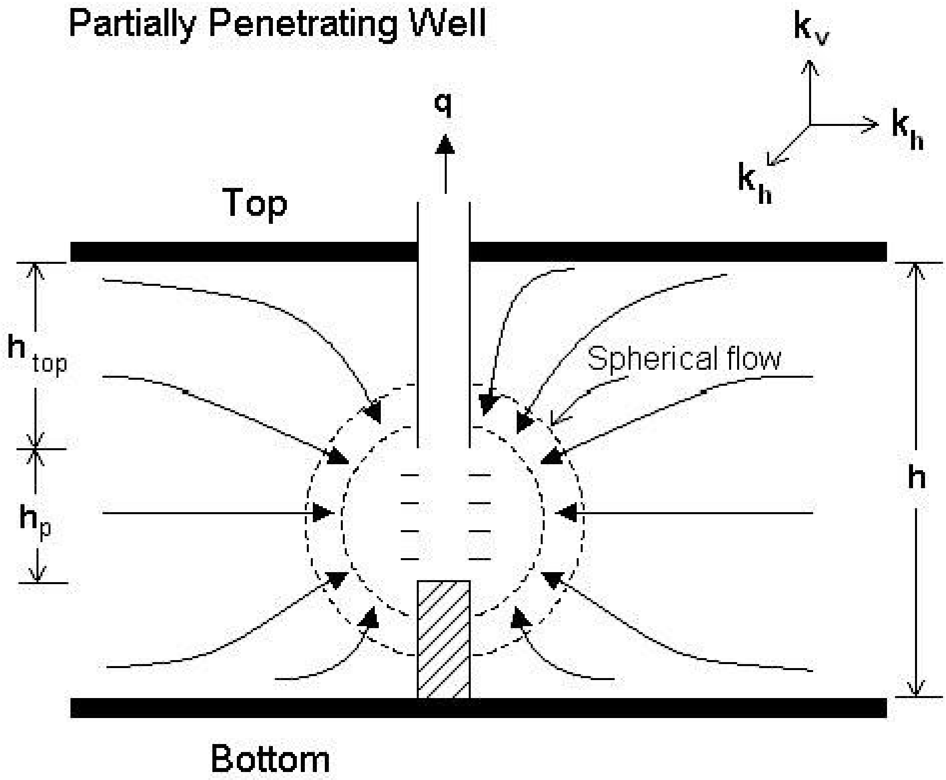


Figure3. Illustration of spherical flow. Note the converging flow lines towards a limited wellbore opening.
From: http://www.fekete.com/SAN/TheoryAndEquations/WellTestTheoryEquations/Spherical_Flow_Analysis.htm

Figure 4 presents the Horner and derivative plot.

Figure 5 shows the whole test data versus linear time plus the zoomed-in build-up. This figure shows that there is no indication of clean-up during the test.
Note the extra model with a flow barrier at 1370 m and a lower permeability of 2200 mD, matching the late derivative also very well. As this model was matched on the early build-up, the pressure difference with the late build-up is the 0.03 bar, discussed above. This model gives also a good match, but not better than the infinite model. The presence of a barrier is thus possible, but not proven.

The wellbore storage coefficient is low at 0.160 bbl/psi (3.69x10$^6$m$^3$/Pa) HAG-02 and reduces during the test with a factor 2.5 due to the compression of the gas in the coiled tubing x casing annulus. This model matches the early build-up perfectly.

The static reservoir pressure at gauge depth, 2150 m tvdTBD, is 218.5 bara.

Figure 4 presents the match of the main build-up, both the Horner “straight” line (dark blue) as its derivative (green). The limited-entry (PP) model matches the wellbore storage and spherical flow very well, plus the derivative of the late pressures. There is thus no doubt about the obtained permeability. Nor about the skin of 20 of the fully open radial model.
And the only explanation for this high skin is indeed the spherical flow.
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.

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 hours, with a final effective time of only 6.2.

As both gauges gave essentially the same response, only those of the top gauge, corrected for the small shrinkage step, have been used.

The match of all pressure data is presented in Figure 5 for both models. The PP model fits the early data, the fully-penetrating model only the final data of the build-up.

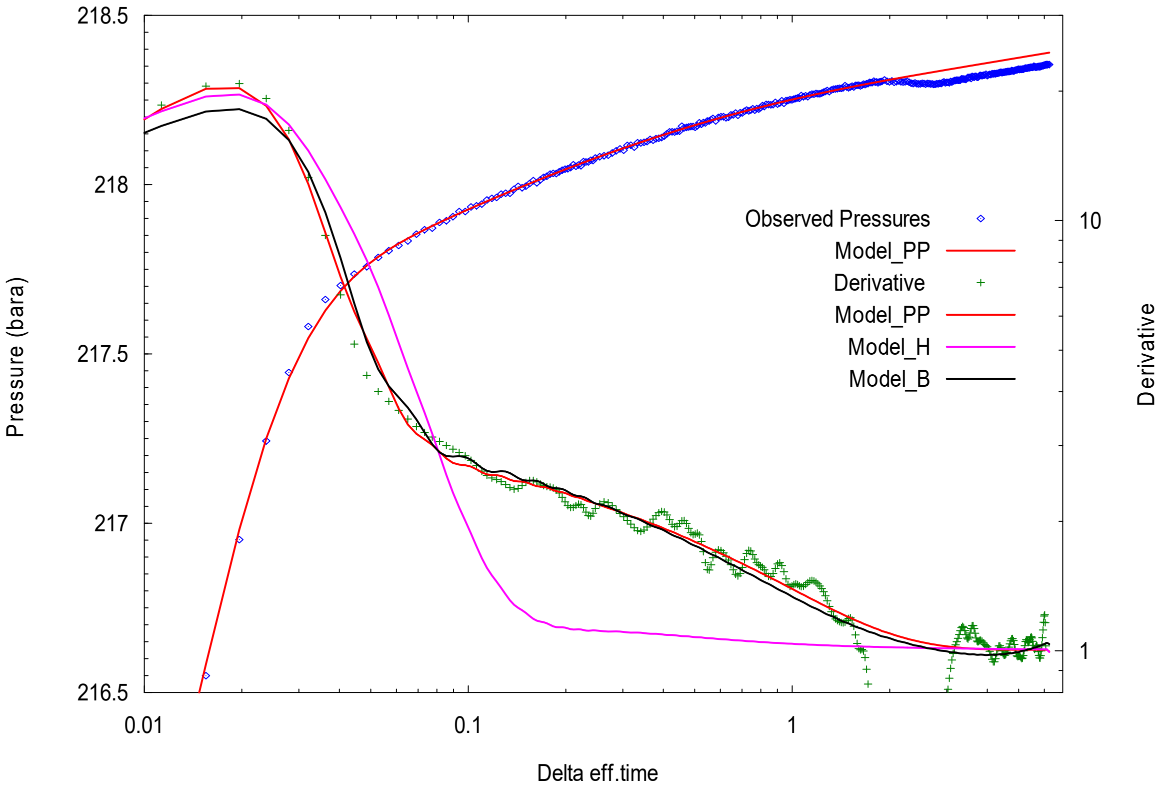


*Figure 4 HAG-GT-01, Horner Plot & Derivative, Main Build-up, Top Gauge*

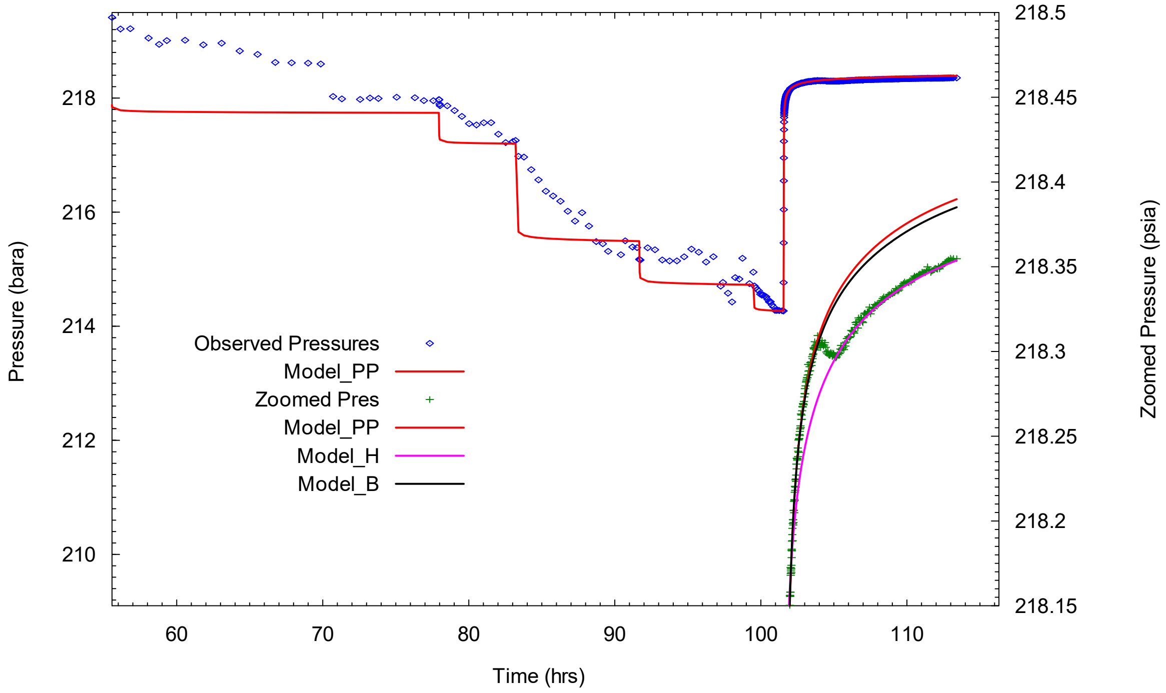


*Figure 5 HAG-GT-01, History & Zoomed Build-ups, Top Gauge*

# 8 Inflow model

A vertical inflow numerical model has been used to determine what part of the wellbore is plugged. The model incorporates the friction in the pipe with the calculated steady-state inflow performance. Any transient behaviour is neglected.

Parameters from HAG-GT-02 have been used for friction calculation across the pipe and screens.

The gamma-ray-permeability relation from TNO report R10260 has been used. The permeability had to be manually increased to match the found KH (=145000mDm). This method is prone to large errors and is not recommended practice. However, it is the best that can be done with the available data.

A model match was found by setting the permeability values for depths < -2244 mTVDBRT (=2610AHBRT) to zero. The resulting cumulative flow- depth plot can be seen in Figure 6.

Resulting friction skin factor @ 94m3/h is on average ~1. This is not a perfect match, but given the precision of the analysis this is within the expected range of uncertainty. The skin-depth plot can be found in Figure 7.

An illustration of potentially plugged screens can be found in Figure 8.

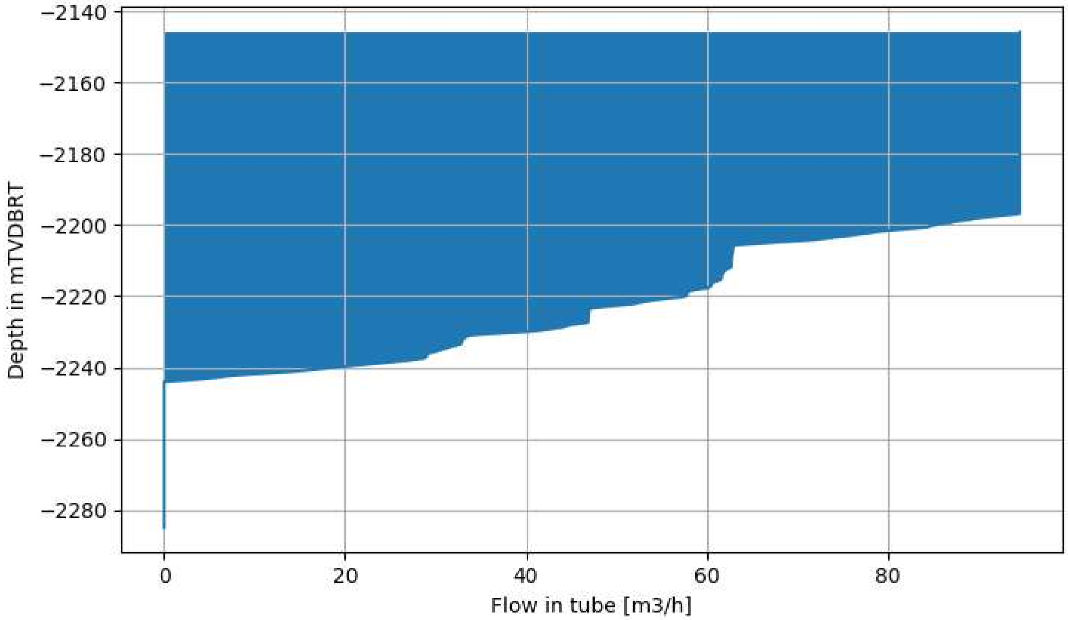


*Figure 6 Model of cumulative flow in pipe*

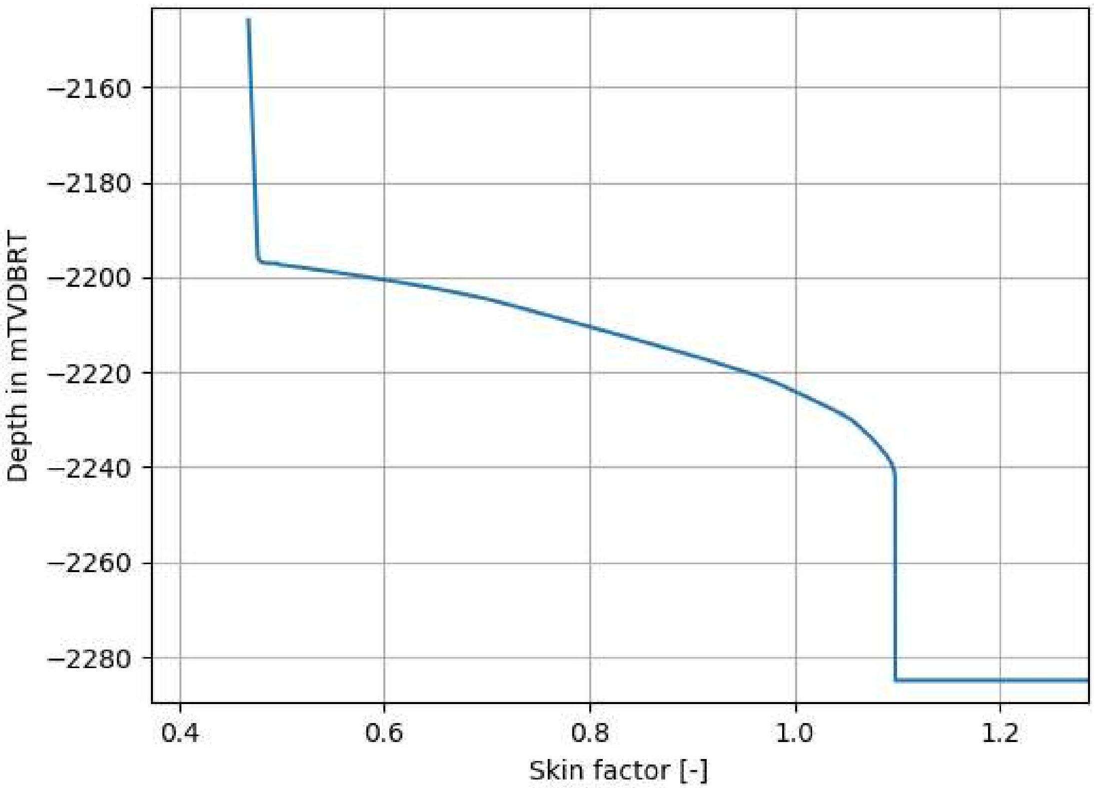


*Figure 7 Friction Skin factor as function of depth at flow-rate = 94m3/h*

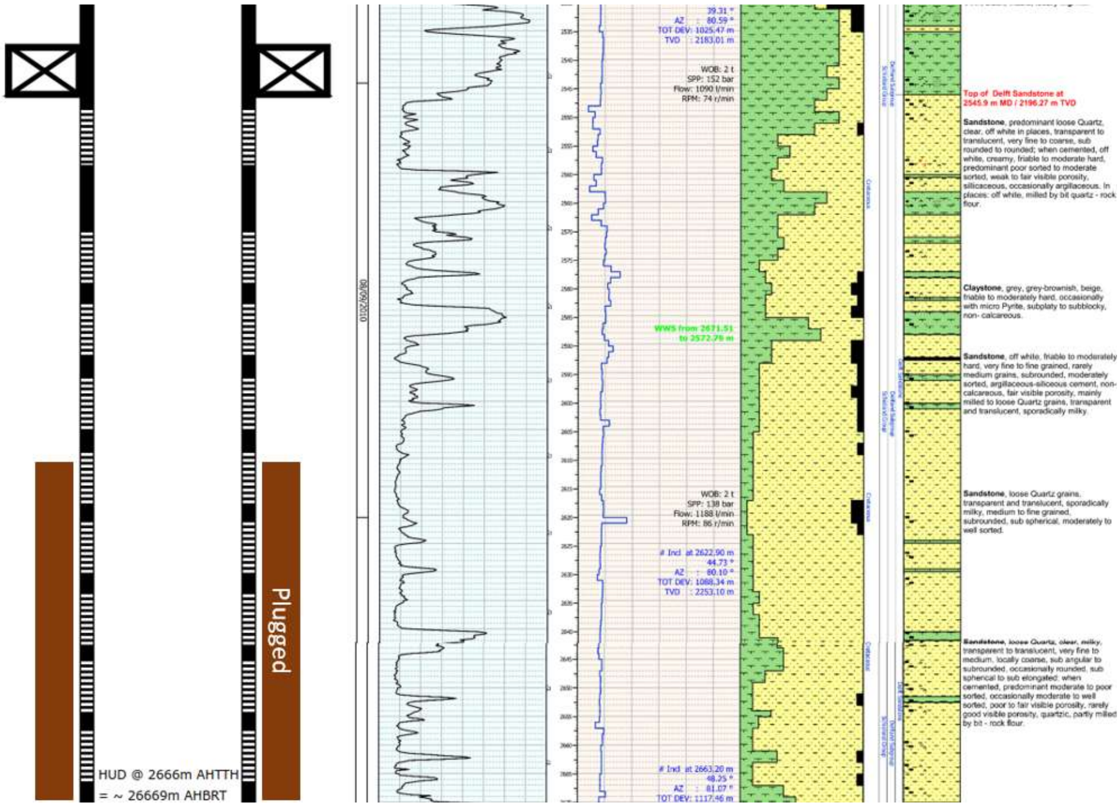


*Figure 8 Illustration of potential plugged lower reservoir section.*

# 9 Recommendations and lessons learned

- The pressure drop 3 hours after CI, caused by the nitrogen lift, does not affect the model match other than a change in reservoir pressure before and after this 0.03 bar drop.

- In order to estimate the radius of investigation at the end of the spherical flow, a barrier was placed at 500 m and was just observed at that time. The vertical flow is thus concentrated in a circle with a radius of 500 m around the well.

- The well did not show signs of a further clean-up during the test. However analysis was hindered by noisy data during the production phases of the test.

- The build-up information is short 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 Build-up to 24 hours.

- in order to make a better flow dependent skin determination: Try to maintain at least 4 different flowrates for longer times at a constant N2 injection rate and choke size

- The hypothesis that the lower part of the well is blocked, is quite uncertain. Prior to any potential mechanical or chemical stimulation, it is advised to test the well and run a PLT (spinner tool) to assess the inflow performance per layer.