Green Well Westland

HON-GT-01-S1

Blockage investigation

Prepared by:	WEP
Author:	Kornelius Boersma
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Agreed:	Maarten Middelburg, Henny Cornelissen, Dick Swart, Alexander Nagelhout

WEP Well Engineering Partners

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Prepared by: Well Engineering Partners
Toldijk 17-19
7900 AP Hoogeveen (NL)
Tel: +31 528227710
http://www.wellengineering.nl/

Executive summary

The Green Well Westland geothermal doublet encountered production issues in the well HON-GT-01-S1 in the 3rd quarter of 2014. Production was required to be ceased in November 2014 due to the persisting issues and an increase in required pump power.
Wireline operations have been performed to identify the source of the problem. A blockage was found in the well at 2422m consisting of Rodenrijs claystone, with pieces of ca. 3cm recovered by bailer. A coiled tubing operation was then performed to attempt to remove the blockage without success.
Primary source of the blockage material is expected to be damage to the 4 ½" liner in the interval from 2470 to 2500m, where a casing connection is likely eroded away due to high local flow velocities in combination with vortices as a result of the irregular internal surface of the BTC couplings.
Solids are likely to have accumulated on top of a liner hanger and slumped down into the well, which was seen in the surface equipment as sudden fill of the filter package.

In order to prevent problems as described above it is recommended to apply the following modifications in the well:

- Maximize ID of tubing to reduce flow velocity
    - Increase OD as well to prevent reduction of wall thickness
- Use internal flush casing connections (premium connections)
    - Remove uneven surfaces at casing collars

Samenvatting

Het Green Well Westland doublet liep in het 3e kwartaal van 2014 aan tegen operationele problemen in de productieput HON-GT-01S1. Productie moest in november 2014 stilgelegd worden vanwege de aanhoudende problemen en de resulterende toename in benodigde pompkracht.
Wireline operaties zijn uitgevoerd om de oorzaak van de problemen vast te stellen. Een blokkade, bestaande uit Rodenrijs kleisteen, werd aangetroffen op 2422m. Stukken klei van ca. 3cm werden naar boven gehaald met een 'bailer'. Een coiled tubing operatie is vervolgens uitgevoerd om de blokkade te trachten te verwijderen. Dit was zonder succes.
Schade aan de 4 ½" liner tussen 2470 en 2500m is waarschijnlijk de primaire bron van de verstopping. Hier is een casing koppeling waarschijnlijk zwaar beschadigd als het gevolg van erosie door hoge lokale stromingssnelheden, in combinatie met vortices veroorzaakt door oneffenheden aan de binnenkant van de gebruikte BTC koppelingen.
De materialen die bij het gat de put zijn binnengetreden zijn waarschijnlijk geaccumuleerd boven een liner hanger. Na verloop van tijd is deze accumulatie teruggevallen in de put, wat in de filters van de bovengrondse installatie is opgemerkt als het plotseling vollopen van de filters met klei.

Om de hierboven beschreven problemen te voorkomen worden de volgende aanpassingen aanbevolen:

- Vergroot de binnendiameter van de liner om stromingssnelheden te beperken
    - Buitendiameter van de liner ook vergroten om voldoende wanddikte te houden
- Gebruik van 'internal flush' (intern gladde) 'premium' casing connecties
    - Verwijderen van riggels en randen aan binnenkant van casing koppelingen.

Contents

1 Introduction

The Green Well Westland geothermal doublet encountered production issues in the well HON-GT-01-S1 in the 3rd quarter of 2014.
Starting September 2014 increasing quantities of clay were found in the surface filters. Up to that date the filters were only occasionally cleaned to remove the hydrocarbon film which aggregated on the filters. In the following months the quantities increased, until production was required to be ceased in November due to the persisting issues and an increase in required pump power.

To investigate the situation the following actions have been undertaken to date:

- 25-07-2014 preventative ESP function analysis by Centrilift – All OK
- 13-10-2014 data analysis Centrilift - no abnormal values found
- 22-10-2014 consult with Baker Hughes Centrilift
    - fluctuations in flowrates
- 29-10-2014 consult with Baker Hughes Centrilift
    - continued fluctuations and reduction of intake pressure
- 05-11-2014 meeting with Baker Hughes Centrilift, Coil services & Staalduinen
    - Discussed suggested coarse ahead with production issues.
- 06-11-2014 Injection test 1, couple m^3 water, free injection
    - After consult with Coil Services, Baker Hughes, AAB & Staalduinen
    - Test source of blockage – internal in well, or external on screen section
    - Increased productivity after restart production
- 08-11-2014 Injection test 2, additional couple m^3 water
    - No further increase in productivity after restart production
- 10-11-2014 Injection test 3, water under pressure
    - Decreased productivity after restart production
    - Production not economically feasible
- 19-11-2014 Retrieve ESP
    - No damage on ESP or tubing noted
- 20-11-2014 Slickline operations
    - Bailer runs (rubber piece) & LIB @ TOL (2397m)
- 21-11-2014 Slickline operations
    - Bailer runs (clay/stone & steel) & LIB (no clear imprint)
        - Clay sample analysed by Panterra Geoconsultants
- 25-11-2014 Slickline operations
    - Camera runs to TOL (2397m) & HUD (2422m) – no clear pictures
- 15-12-2014 Rig up coiled tubing
- 16-12-2014 Coiled tubing operations
    - Attempted injection test with up to 30 bar injection pressure.
        - Well plugged, pressure stable for 30mins
    - Milled to 2427m
- 17-12-2014 Coiled tubing operations & rig down
    - Milled to 2429m

1.1 Reference documents:

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3. **T&A Survey.** *End of Well Report for Geothermal Production well (HON-GT-01/ST01).* 2012.
4. **Hughes, Baker.** *Treatment reports Greenwell.* 17-12-2014.
5. **Weerd, Anne A. van de en Munsterman, Dirk.** *G1156; Notitie onderzoek naar een klei monster in HON-GT-01 ST1.* sl : Panterra Geoconsultants, 04-02-2015.
6. **Geoservices.** *Final well report HON-GT-01 & HON-GT-01-ST1.* 2012.
7. **GreenWell.** PO-GWW-HON-GT-032-TransmarkEDS. 2012.
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9. **Drilltec.** *Data from Compact Rig data recorder (pressure, torque, hookload, recorded depth etc.).* 03-03-2012.
10. **TESCO.** *Torque tables.*
11. **GOT.** GOT-LH-GWW_51048. 2012.
12. **API.** *API-RP-14E Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems.* 1991.
13. **GPC.** *CHIMD GreenWell water analyse.* July 2013.
14. **AAB.** *Verslag wanddikte metingen van de joints bij aardwarmteproject: Green Well Westland.* 16 oktober 2013.
15. **GreenWellWestland.** *Verslag van wanddiktemetingen, project: Green Well Westland.* 23-03-2015.
16. **BWG Geochemische Beratung.** *Geochemical investigations of water and solid samples at Honselersdijk Gt 1 during the hydraulic test on 07. and 08. March 2012.* 2012.
17. **Drilltec.** *DDR 72.*
18. **Vandervalk+Degroot.** *Rapportage: Rijdende camera (34210288).* 7-8-2014.

2 Observations

Below are some notable observations from the performed operations.

2.1 Retrieved Electric submersible pump (ESP)

In 2013 the 6 ⅝" production tubing was replaced after erosion-corrosion effects on the BTC couplings on the old tubing. The couplings showed small holes (see Figure 1). A study to the cause & solutions was performed by Technisches Büro Karl GOLLOB GmbH (1).

Figure 1: Damaged connection on production tubing 2013. Holes marked in yellow circle.

The new tubing had internal flush BTC SC couplings installed. After pulling the ESP no damage on any part of the ESP was reported. No damage was observed on the connections in the string; connections were 'as new'. See also Figure 2.

Figure 2: Inside of coupling on 2013 installed production tubing (picture taken on 19-11-2014)

2.1 Slickline operations (2)

A total of 13 slickline runs have been performed on 20 & 21 November 2014.
Of which:

1x dummy run w/ bullnose
6x bailer run
4x lead imprint block (LIB)
1x spear
1x wiregrab

More details are listed below:

- 3,5” bullnose. Stood up on hold up depth (HUD) @ 2422m
  - This is ca. 50m above the 7” casing shoe @ 2471m (3)
- 2 ½” bailer run to 2422m. (empty)
- 3 ½” bailer. Stood up at 2397m.
- 3,75” LIB to 2397m
  - Imprint of top of liner (TOL) of the 4 ½” liner hanger (Figure 3).
  - This approximately matches the installation depth of 2400m (3).

Figure 3: Impression of TOL @ 2397m on 1st LIB run with 3,75" LIB

- 3,5" bailer to 2397m (empty)
- 3,5" bailer to 2422m
  - Found traces of stone + piece of rubber (Figure 4)
  - The origin of this rubber is not sure
    - Does not originate from the 4 ½" x 7" liner hanger (*verbal by GOT)*

Figure 4: Ca. 4" piece of rubber retrieved from HON-GT-01S1 from 2422m with bailer run

- 2,75” LIB. stood up at 2397m
    - Showed no marks (Figure 5).

Figure 5: Result of second LIB run to 2397m with 2,75” LIB - no marks

- Spear with 2,25” fluted centralizer. Stood up at 2422m.
    - No overpull when POOH
- 2,25” LIB with 3,5” fluted centralizer to 2422m
    - Various small marks on LIB (Figure 6). Source undefined

Figure 6: Result of third LIB run to 2422m with 2,25” LIB – various small marks

- 2 leg wiregrab to 2422m jarred down,
    - No overpull when POOH

- 2,25” LIB with 3,5” fluted centralizer to 2422m
    - No clear marks on bottom LIB
    - Lead on side of LIB stripped upwards by a tube shape – possibly TOL

Figure 7: Result of fourth LIB run to 2422m with 2,25” LIB – lead stripped upwards by tubing or TOL

- 2,5” bailer stood up at 2397m
- 1,75” bailer to 2422m. Jarred down 30 times
    - POOH with 300 lbs overpull
    - Retrieved half a cup stone, clay and iron debris from 2422m
    - The larger pieces were ca. 3cm in size. (see Figure 8).

Figure 8: Ca. 3cm claystone piece from HON-GT-01-S1 retrieved from 2422m with bailer run

2.2 Slickline camera operations (2)

Three camera runs have been performed on the 25th November 2014:

- Memory camera run to HUD, take pictures @ 2422m
    - 1 leg of bow spring centralizer broken off
    - No clear vision
- Memory camera run to TOL, take pictures at @2397m.
    - No clear vision.
- Memory camera run to HUD, take pictures from 2397 to 2422m
    - No clear vision

An example image of the retrieved pictures from the well is shown below (Figure 9).

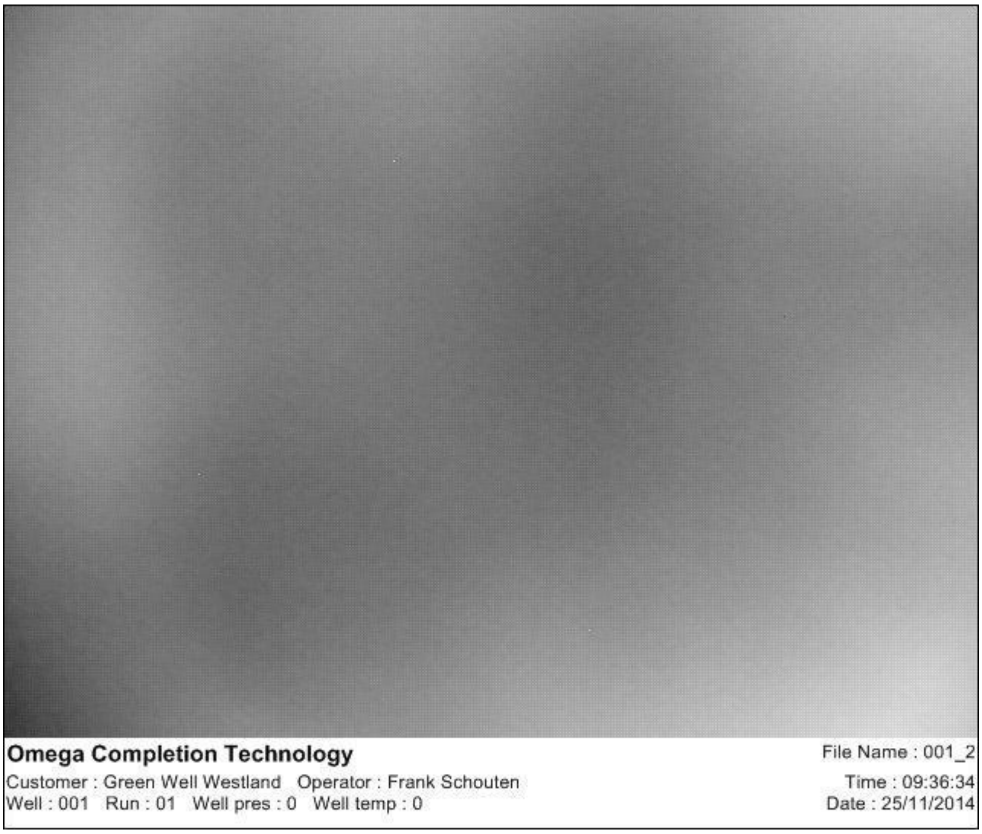


Figure 9: Example image from camera runs on HON-GT-01S1 taken on 25-11-2014

2.3 Coiled tubing operations (4)

An injection test was performed on the well with water. The pressure was building to 30 bar, after which the pump was stopped. Pressure was monitored for 30mins during which it remained stable (Figure 10).

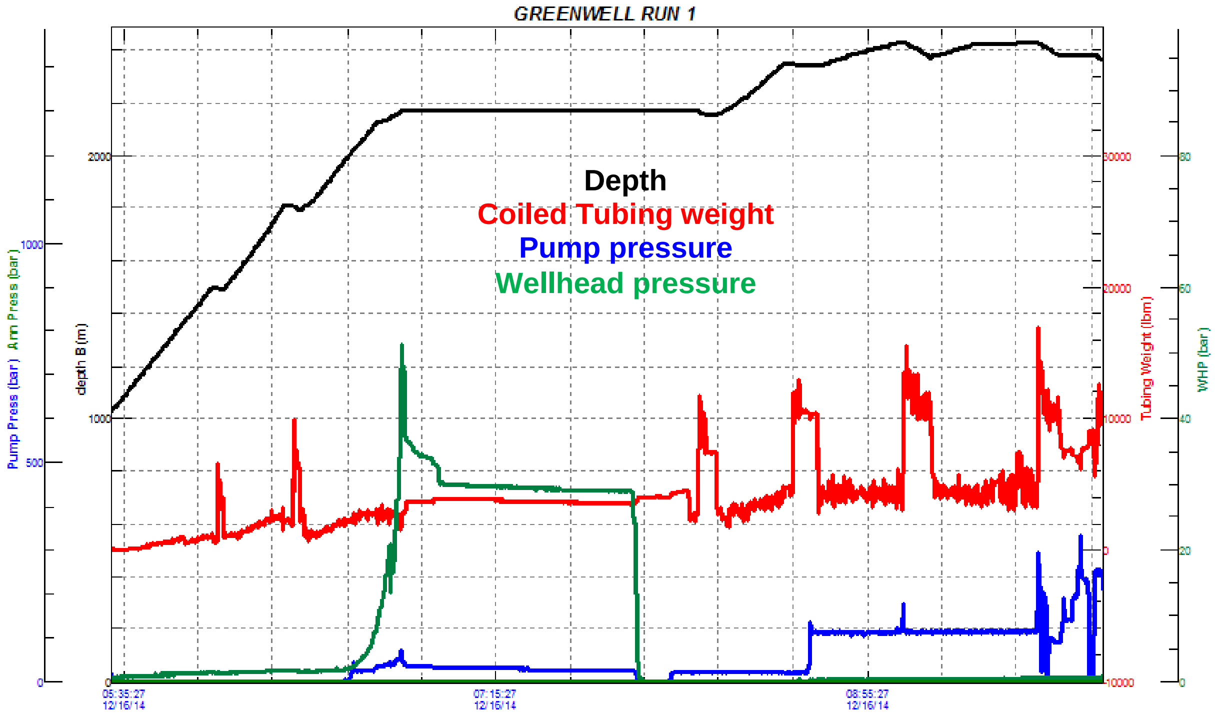


Figure 10: Data plot from injection test on HON-GT-01S1 on 15-12-2014

With coiled tubing it was attempted to mill past the HUD @ 2422m. Difficult progress was made to 2429m in three days with 2 BHA runs.

During the milling operations the fluid returns from the well were monitored and found to be carrying similar solids particles (claystone) as found in the production filters before. Flowrates were however limited to 275 l/min, which would be insufficient to remove larger cuttings from the well. As a result the blockage material has only been temporarily moved upwards, after which it settled back into its original position.

3 Data analysis

A blockage in the well was encountered at 2422m. The location of the blockage is marked below in the well schematic (Figure 11). 7 meters of the blockage were milled out by CT. The remaining thickness of the blockage is unknown, but is expected to extend to at least 3m. After the injection/pressure test to 30bar it was confirmed that a clay plug would need to be several meters, likely >10m in thickness to hold such pressure (*Panterra Geoconsultants, verbal*)

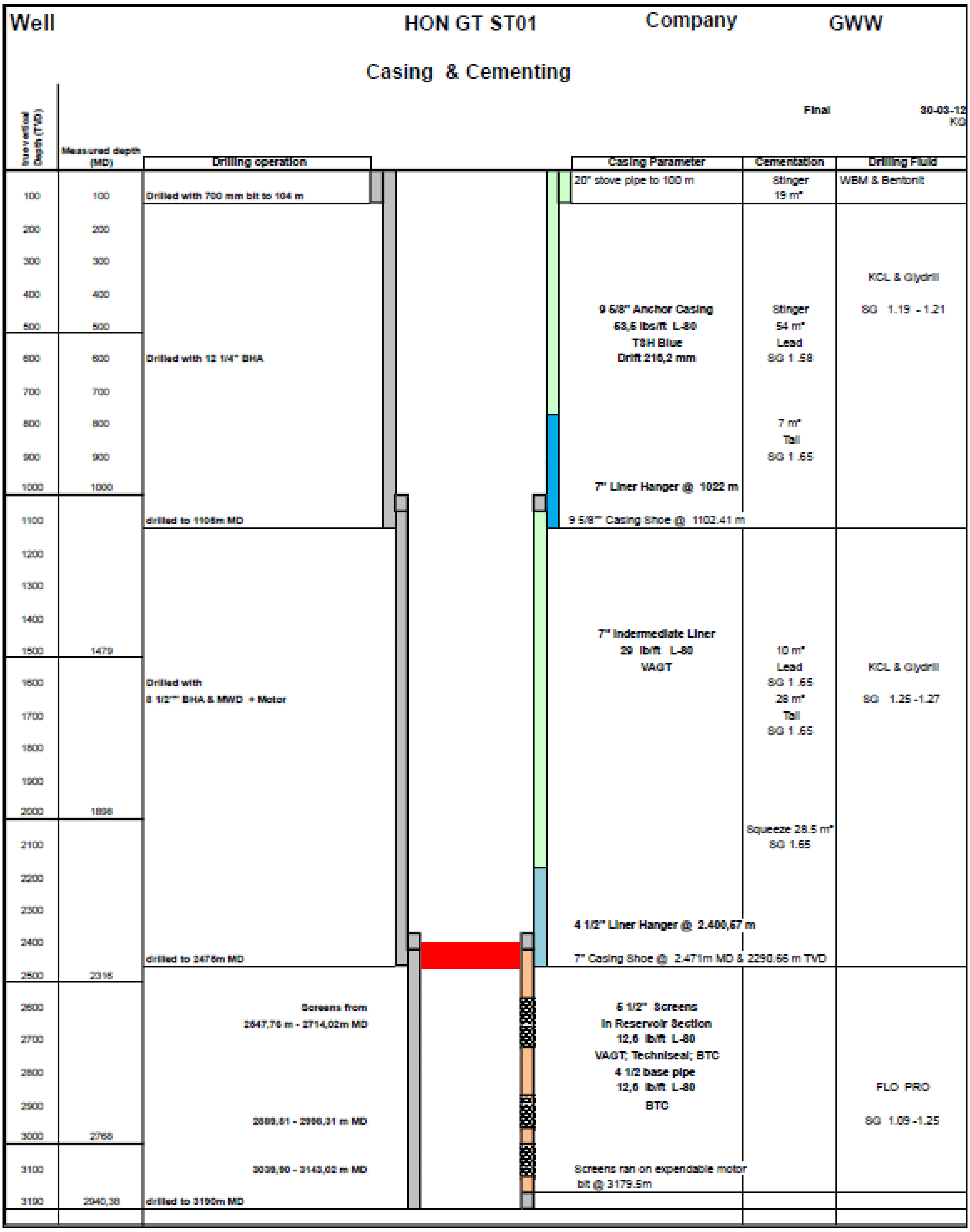


Figure 11: HON-GT-01ST1 well diagram (3). Plug marked in Red (thickness unknown).

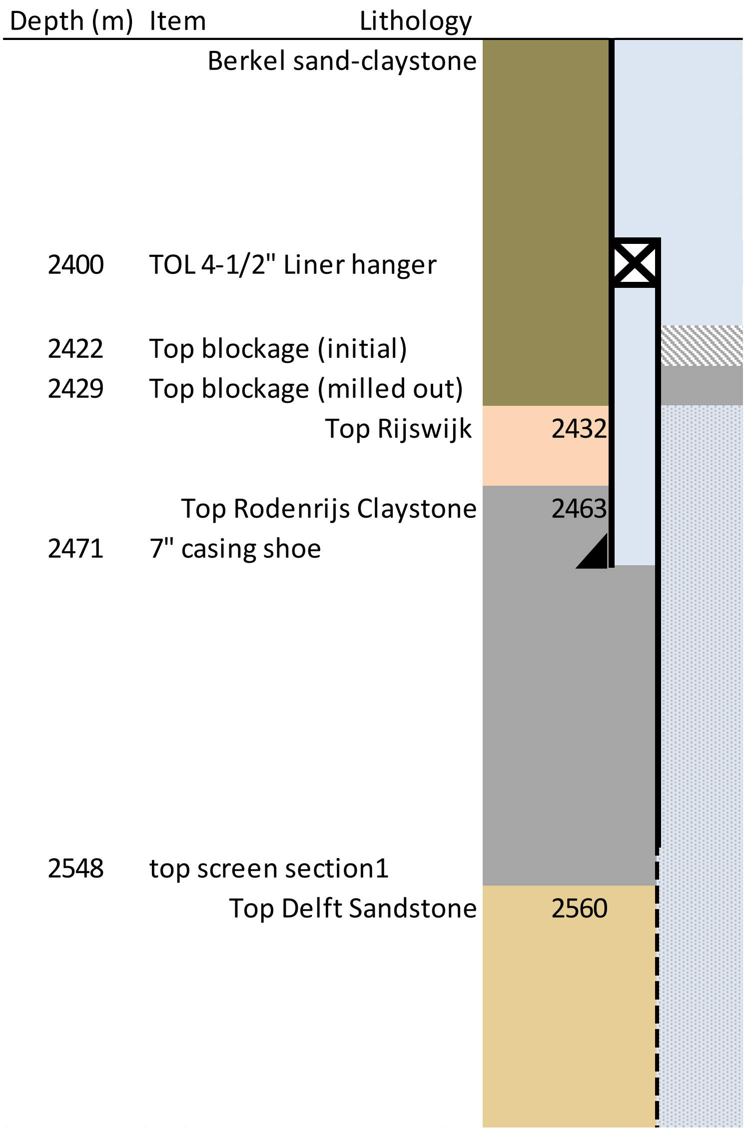


Figure 12: Zoomed in section of well schematic at area of interest (vertically approximately to scale)

During the operations the following materials were found in the liner:

- Iron scraps (carbon steel, no stainless)
- Clay
- Claystone pieces up to 3cm in size
- Ca. 4” diameter circular/oval rubber piece

3.1 Clay analysis

The size of the larger pieces of clay are, with 3cm, well above the maximum screen size of 300µm (3).

The clay retrieved by the wireline bailer operations was analysed by PanTerra Geoconsultants (5). The clay sample was found to originate from the Rodenrijs Claystone, which was found between 2463 and 2560m (6). The microfossils found in the sample matched a sample as retrieved from well VDB-04. From this analogy the sample was allocated more precisely to the upper 30m of the Rodenrijs Claystone. Therefore it would come from approximately between the 7” casing shoe (2470m) and 2500m MD.

Since all solids which arrived at the filters have been processed through the ESP it is likely that larger pieces of clay (if present at that point) would be crushed by the pump. Due to the soft nature of the claystone this would not give significant damage to the ESP.

3.2 Wellbore/liner plugging

During the production period to November 2014 an increase in required production pump power for production was reported, which indicated the well could be plugging. During the slickline and coiled tubing (CT) operations this was confirmed by the following:

- Stood up with both slickline and CT on 2422m inside the 4 ½" liner
- Successfully pressure tested the well system to 30 bar
    - No injection possible at this pressure.

From the retrieved materials the most likely source of plugging is a clay plug inside the liner. Prior to start of the slickline & CT operations injection (albeit with uneconomical rates) was still possible. The slickline operations (especially imprinting with LIB block) and the later attempted injection test (at the start of the injection test) have likely compacted the clay inside the 4 ½" liner. Up to the point at which injection was not possible at all anymore.

3.3 Source of clay in blockage

Based on the observations in the well operations a number of options as the source of the clay blockage are listed below with the respective relevant findings & observations.

3.3.1 Screen damage

The iron scraps found in the well could indicate steel damage to the liner or the screens. Damage to the screen section is highly unlikely as source of the blockage because of the following:

- Holes in pre-perforated pipe 12,5 mm
- Clay sample from above 2500m, which is 50m above the uppermost screen joint.

3.3.2 Blank pipe damage – casing coupling

The iron scraps found in the well could indicate damage to the liner. Because the liner joints are smooth they are unlikely to be damaged on the pipe body. Potentially a casing connection may have failed.
The connection would be required to be either fully parted, or contain large holes:

- Claystone pieces up to 3cm in size

The screen sections are expected to be stuck to the formation, which would prevent the lower part of liner from falling down into the rathole in case of a parted connection.

Due to the blockage in the liner and the absence of 'hold down' slips on the liner hanger the upper part of the liner could have moved upwards as a result of the pressure differential over the blockage during production. This would expose a larger section at the parted connection. However the Top of Liner was encountered at the same depth as originally installed. It is therefore unlikely that the liner as a whole has moved upwards.

Because of the above severe damage at of the blank pipe joints is expected to allow the large clay pieces to enter the wellbore.

3.3.3 Liner hanger damage

In case of damage to the liner hanger the packer, which sealed the 4 ½" x 7" annulus would be lost. The retrieved pieces of rubber could potentially be (a piece of) this packer. The liner hanger producer (GOT) however inspected the rubber and confirmed verbally that the rubber could not come from the liner hanger as it had the wrong colour, shape & hardness.

In case of a lost seal on the hanger this would open up an additional flow path outside the screen section. The maximum free size in this opening would be 1,184” (3cm):

- 4 ½” tubing with 5” coupling OD
- 7” 29ppf liner has 6,184” ID
- Severe liner hanger damaged, so no further restriction assumed.

Testing with clay samples on liner joints at surface showed however that these did not fit through the annular clearance due to their shape. Based on this the larger claystone pieces could not have come from behind the liner hanger.

In addition, in case of a failed packer, the annular area would be required to be plugged somehow at a later stage. Since this was also proven to be plugged to be plugged by the CT injection tests. The slickline operations were all performed inside the 4 ½” liner, which provides no explanation for an increase in plugging of the 4 ½” x 7” annulus after the 3rd injection test

3.4 Location of blockage

The blockage was encountered at 2422m, while the source of the blockage material is reported to come from the Rodenrijs Claystone (2463 to 2500m). This indicates that the material has moved upwards from its original position prior to blocking the well.

3.4.1 Upward movement of blockage inside liner

During the initial stages of the blockage the material could be pushed upwards due to the pressure differential above and below the blockage. This pressure differential would be caused by the ESP during production. At the ESP this would be seen as drawdown. Since part of the pressure would be lost while moving up this would result in an increased drawdown on the ESP, which was reported from October onwards.

3.4.2 Avalanche mechanism

The first plugging issues came to light after a prolonged period of low production rates. Therefore there might be the potential for suspended solids to settle down. This would typically occur at the top of the 7” liner hanger. Here the fluid velocity is reduced significantly inside the larger 9 ⅝” casing (see chapter 6).
Such a landslide could be triggered by various events

- Overloading after continuous material build up
- Sudden pressure surges

3.5 Conclusion

Based on the observations of both the wireline and coiled tubing operations it is very likely that the production liner is severely damaged at one or multiple positions in the interval from 2500 to 2400 considering the following:

- Pieces of Rodenrijs Claystone formation have been found inside the 4 ½” liner
    - The 7” casing shoe is placed in the Rodenrijs Claystone (3)
    - The Rodenrijs section is covered by blind pipes from 2548m upwards (3)
    - Screens on Rodenrijs section from 2548 to 2560m (6)
    - Claystone pieces (3cm) exceed screen sizing:
        - 300μm for WWS
        - 12,5mm for pre-perforated pipe
    - Claystone pieces matched to upper 30m of Claystone (above 2500m)

- Plugging/obstruction found inside 4 ½” liner @ 2422m
    - 7” shoe place at 2471m (3)
    - 4 ½” liner plugged ca. 50m above 7” shoe
    - Reduced injection after injection tests under pressure & slickline operations

Damage to the 4 ½” x 7” liner hanger can be excluded:

- Piece of rubber retrieved from 2422m
    - Not from liner hanger (*verbal by GOT – wrong colour, shape & hardness*)
- Pieces of Rodenrijs Claystone formation have been found inside the 4 ½” liner
    - Claystone pieces (3cm) did not fit annular clearance 7” x 4 ½” liner
        - Confirmed by tests on surface
- Damage on the liner would expose the 4 ½” x 7” annulus
    - Injection tests showed plugged well, including annulus

The plugging of the well may have been aided by a ‘landslide’ type material drop inside the well after a period of ceased or decreased production.

4 Reactive torque mud motor

4.1 Potential issue:

When installing the WWS liner section a sacrificial mud motor was included below the screens to be able to work the pipe past any tight spots when required. Potentially the reactive torque from the motor while working through such tight spots might have caused a casing connection to disconnect. This is further explained below.

4.2 Review of data:

Mud motor capacity:
Mud motor torque is generated by the differential pressure over the motor. The motor in use was a “Black max mudmotor 4/5L 6,3 stage” (7). This motor can generate up to 3,1 kNm at 66 bar differential pressure (8).

Torque/pressures while running in hole liner (9)**:**
While running in the maximum reported surface pressure is 91bar/400lpm at 3050m while washing the string down. The free rotating pressure at the 7” shoe was 70bar/400lpm. Based on this, the maximum differential pressure on the motor with torque at the bit was 21bar. The maximum produced torque at the motor was therefore 1,0 kNm

The liner was not rotated while running in.

Reactive torque at surface has been recorded to maximum 0,96 kNm while pumping 400lpm/70bar.

Casing couplings:
Casing make up torque was not reported (BTC couplings are made up to mark, not specified torque), but estimated torque values for 4 ½” BTC couplings are ca. 4,5 kft lbs (6,1 kNm) (10).

Stick-slip:
In case a stick-slip situation was encountered the reactive torque from the mud motor may have been temporarily increased from the standard torque. This situation is not likely to occur in the HON-GT-01 wells as it typically occurs on high friction formations (such as Chalk).

While running in no stick-slip related signs were reported.. Both circulating pressures, flowrate and torque readings have been stable while running in the liner.

4.3 Conclusion:

It is highly unlikely the mud motor has generated sufficient torque to release a BTC connection in the liner while running in:

- The motor could produce maximum 3,1 kNm
- The recorded data indicates the maximum generated motor torque is 1,0 kNm
- Ca. 6,1 kNm would normally be required to release a BTC connection

5 Erosion - corrosion

5.1 Potential issue:

For the production of geothermal heat from the well, particularly in the winter periods, high flowrates were in use. These high flowrates could cause the creation of high turbulent flow and local vortices, especially in areas where ledges or irregularities on the tubing wall are present. Such vortices can potentially lead to pipe erosion, especially in combination with solids or gasses in the fluid.
Local corrosion of the liner may have aided the above process. This would be a similar process as had occurred on the production tubing in 2013 (1). However due to the increased depth and resulting pressure regime at the liner it may have required more time to take effect.

5.2 Review of data:

Casing couplings:
The 4 ½” production liner has BTC couplings. These leave a small ‘open’ space between the casing joints. In this space the coupling thread is exposed, which gives both a small ledge and an irregular surface (see Figure 13).

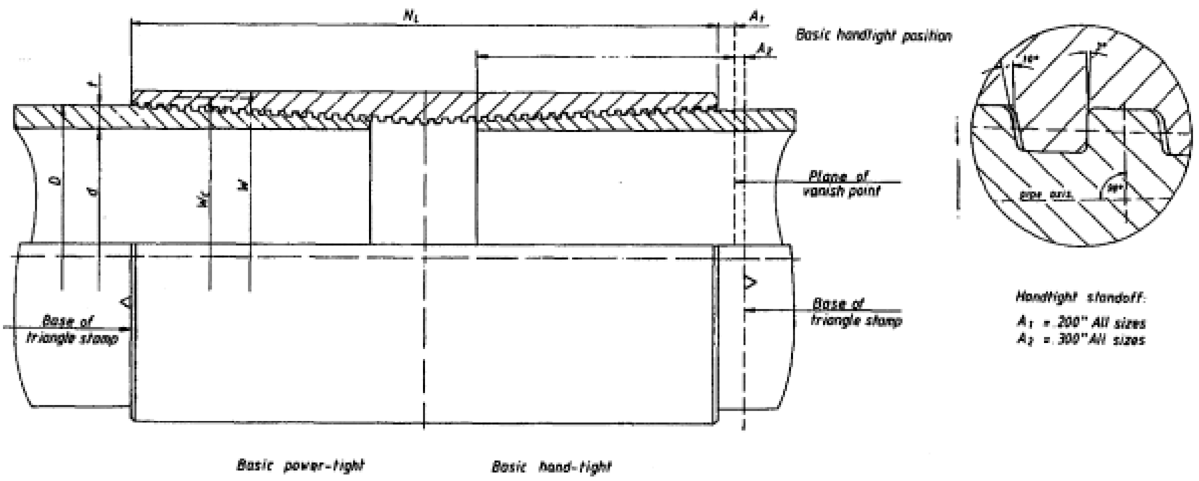


Figure 13: Schematic drawing of a BTC connection (*Source: Weatherford Tubular connection data book 1992*)

Liner hanger (11)**:**
The liner hanger has a reported internal diameter (ID) of 98,8 mm (3,89”). This is slightly less than the ID of the 11.6ppf 4 ½” liner (4”). The length of this restriction is ca. 1m in length. Above this section the liner hanger opens up in two ca. 1m steps to 4,27” and 5,26”.
Total liner hanger length is 2,7m. The TOL has a an ID of 5,26” and OD of 5,77”.

Production rates:
The fluid production rates in 2014 have been listed below (Table 1). The issues in the well caused the production to remain relative low after September 2014.

Table 1: 2014 Production data from HON-GT-01-S1 (*Source: Green Well Westland*)

	Jan	Feb	mrt	apr	mei	jun	jul	aug	sep	okt	nov
Debiet (m3/h)	170	155	147	124	114	93	81	91	90	90	90
P intake (bar)	20,0	21,7	24,7	28,2	29,4	32,0	34,3	33,7	33,4	28,8	26,0

In addition to the table above it is reported by Green Well Westland that during the winter period of 2013-2014 the production was increased to 180m3/hr for a couple of days.

Maximum recommended flowrates:
The recommended maximum flowrates for fluids in pipes are specified by the API (12), see also the formula below:

$$Ve[\mathrm{ft/s}] = \frac{C}{\sqrt{\rho_m[\mathrm{lbs/ft^3}]}}$$

Ve = the fluid erosional velocity (ft/s)
ρ_m = the fluid density (lbs/ft^3)
C = empirical constant
"Industry experience to date indicates that for solids-free fluids values of C = 100 for continuous service and C = 125 for intermittent service are conservative. For solids-free fluids where corrosion is not anticipated or when corrosion is controlled by inhibition or by employing corrosion resistant alloys, values of C = 150 to 200 may be used for continuous service."

For a non-corrosive fluid, or where inhibition is present a C-value of 150 can be used. With a brine or water flow the density is ca. 1,1 kg/l, which is ca. 69 lbs/ft^3. This gives a maximum recommended fluid velocity of 20 ft/s, or 6 m/s for a solids free fluid.

Fluid velocities in HON-GT-01:
Based on the provided flowrates the fluid velocities in the 4 ½" liner and the small ID liner hanger section have been calculated. The results are displayed below in Table 2.

Table 2: Fluid velocities (m/s) through the HON-GT-01S1 liner and liner hanger for various production rates

OD (inch)	Wht (lbs/ft)	ID (inch)	Area m^2	Debiet / Flow rate (m3/hr) 90	120	140	160	170	180
Liner hanger		3,889	0,007664	3,3 m/s	4,3 m/s	5,1 m/s	5,8 m/s	6,2 m/s	6,5 m/s
4 1/2	11,60	4,000	0,008107	3,1 m/s	4,1 m/s	4,8 m/s	5,5 m/s	5,8 m/s	6,2 m/s

Based on API-RP-14E it can be seen that the recommended fluid velocities have been exceeded in the small ID section of the liner hanger during januari 2014. In addition this velocity was exceeded in both the liner and the hanger during the few days of producing 180 m^3/hr.

Fluid velocities in some other geothermal projects:
Below are the liner sizes in use in two reference projects with their respective flow rates. The production data has been provided to WEP by Green Well Westland, the liner sizes have been retrieved from the respective end of well reports:

Van den Bosch:
VDB-01 – 5 ½" 20ppf WWS liner w/ XO to 7" liner
VDB-02 – 5 ½" 20ppf WWS liner w/ XO to 7" liner
190 m3/hr – 4,8 m/s

Duyvestein:
PNA-GT-03 – 4 ½" 10,5ppf WWS liner
PNA-GT-04 – 4 ½" 10,5ppf WWS liner

160 m3/hr – 5,3 m/s

Production fluid analysis:
In July 2013 the production water has been analysed (13). This analysis shows the presence of 23,95 mg/l of suspended materials in the fluid. The majority of the materials is smaller than 1,20 µm (clay) (Table 3), with 4% exceeding 8 µm (silt).

Table 3: GPC 2013 production fluid analysis; quantities of suspended materials

MATIERES EN SUSPENSION	mg/l * %
0,20 à 0,45 µm	12,825*53,5
0,45 à 1,20 µm	9,213*38,5
1,20 à 3,00 µm	0,003*0,0
3,0 à 5,0 µm	0,787*3,3
5,0 à 8,0 µm	0,095*0,4
sup. à 8,0 µm	1,027*4,3
TOTAL	**23,95*100**

Inhibition:
During the production of the geothermal fluid a minor amount of hydrocarbons is also produced. This was also observed on a regular basis on the surface filters. These hydrocarbons aid in corrosion inhibition by creating a small protective film on the steel surface.

Production casing observations:
The ESP production tubing was retrieved and visually inspected. No damage on the casing connections (as experienced in 2013) was found.
In 2013 spot measurements on casing wall thickness were performed to investigate corrosion on the tubing joints. No wall thickness reduction in comparison to the installation was observed. (14). After retrieval of the ESP production tubing in 2014 the wall thickness of the tubing has been measured. The results of this measurement showed no notable decrease in wall thickness (15).

Production fluid analysis:
The production fluid has been analysed on two occasions;

- May 2012, During the production test (16)
- July 2013, After the initial issues with the production tubing (13)

The following can be noted from these analyses over the period 2012 to 2013:

- pH at the lab remained constant at ca. 6-6,1
- Cl content 85g/l
- Fe content increased from 72 mg/l to 93 mg/l

The fluid is measured for gas content on 2012 with degassing @ 85ºC.

- 0,8 Nm^3 (gas) / Nm^3 (fluid)
  - Ca. 88% hydrocarbons (mainly methane)
  - Ca. 8,8% CO_2
  - Ca 3,3 % N_2

The fluid is de-gassed on surface at 3 bar pressure to prevent the CO_2 from de-gassing. This keeps the pH stable and prevents corrosion.

5.3 Discussion:

Based on the above listed information in the life of the well it is possible that erosion-corrosion has occurred at places in the well where the flowrate locally accelerates.

This would have caused the following effects:

- Removal of protective hydrocarbon film from steel
- Pipe erosion at rough surfaces
  - Such as the BTC couplings
- Erosion at ledges in string
  - Such as at the lower part of the liner hanger.

In addition to the pipe erosion the high flowrates may have caused extra local vortices at casing collars which would further accelerate the erosion effects.

5.4 Conclusion:

The flowrates in the liner and the liner hanger have during the winter period of 2013 to 2014 reached the maximum flowrates as recommended by API-RP-14E. In combination with the small amounts of suspended solids in the fluid this may have caused erosion, especially at casing collars, where the uneven surface may have resulted in local vortices.

The environment and the presence of Cl^- may lead to some corrosion on an unprotected steel surface. Due to the presence of hydrocarbons in the well a protective film would normally be found on the steel casing which protects it from corrosion. The fluid analysis showed however increased levels of Fe from 2012 to 2013. This may be indicative for corrosion in the well.

6 Avalanching

6.1 Potential issue:

Due to the tapered design of the well the fluid velocity varies with depth. The deepest/smallest ID part of the well having the highest velocity (see also chapter 5) and the uppermost production casing having the lowest.
During periods of relative high flow suspended materials might be carried out of the top of the well. If flowrates were reduced these materials can accumulate at places where the flowrate decreases, such as top liner hangers.

6.2 Review of data:

Amount of solids in fluid:
A water analysis with solids quantities has been performed (13) on July 2013 at 108m^3/hr (see also Table 3).

1,027 mg/l fine silt (>8 µm) and coarser materials is found in the produced fluid. At 100 m3/hr (= 100.000 l/hr) this accumulates to 102,7 g/hr = 2,5 kg/day ≈ 74 kg/month.

Such small quantities of suspended solids may cause plugging of the 4 ½” liner in case the solids are not removed from the well (to surface):
The 4 ½” casing content is 8,1 liter/m
Density of clay sediment ca. 2,65 kg/l
1m casing could contain ca. 21,5kg sediment if fully plugged

It is expected that at least 10m plug would be present inside the well, which would accumulate to ca. 215kg sediments.

Hole cleaning during production:
While producing 90 m^3/hr (as from June 2014 - Table 1) the fluid would have the following velocities inside the casing string:

4 ½” liner:	3,1 m/s
7” liner:	1,3 m/s
9 ⅝” casing:	0,7 m/s

With a salt water fluid (such as the produced fluid), flow is turbulent for all occasions as Reynolds number (Re) >4000. Because of the turbulent flow during the majority of the well life it is highly unlikely that suspended solids would remain in the well.

It has to be noted however that the velocities could locally be less just above the liner hangers where the casing ID suddenly increases. Claystone may accumulate & aggregate together, especially in a wet environment. This could hinder re-activation of settled materials difficult. This characteristic from clay could, over time lead to accumulation of solids at ledges. Below a schematic of the process in three steps (Figure 14)

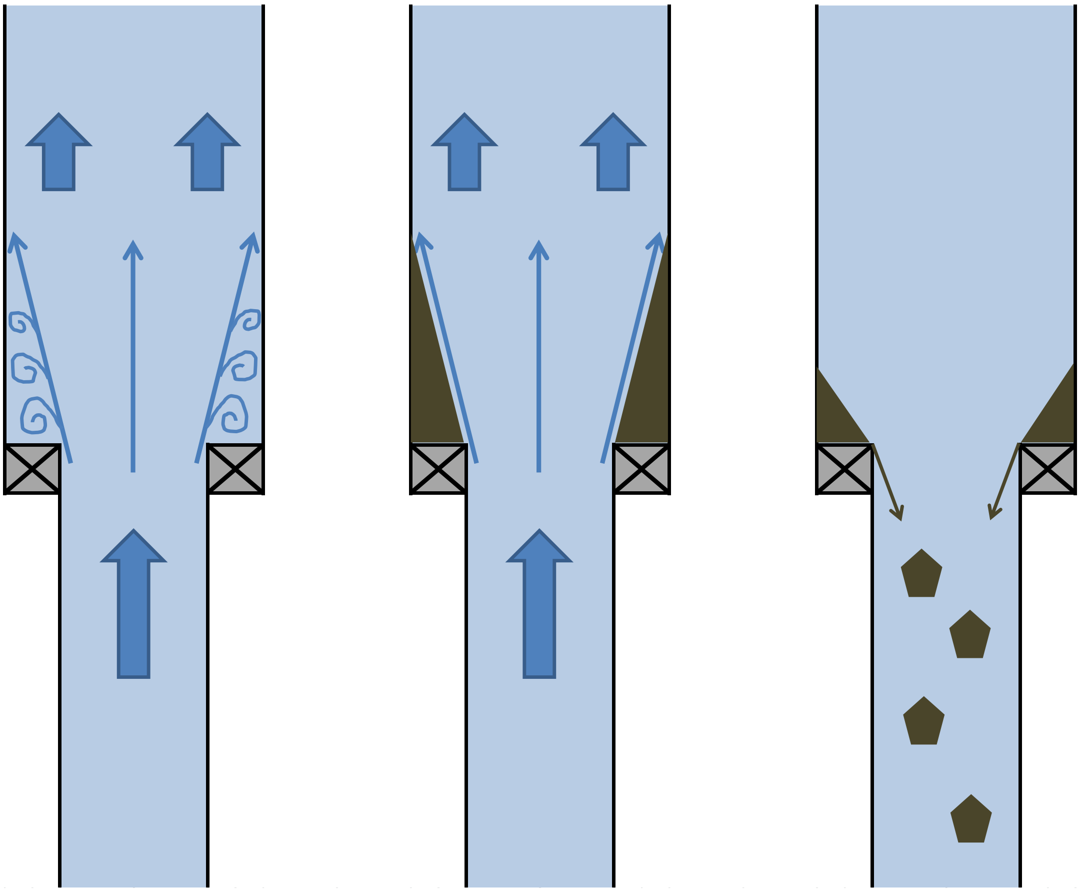


Figure 14: Solids accumulation. Process in three steps left to right: 1 Settling, 2 Build up, 3 Avalanche

Production stoppages:
The 2014 production data have been reviewed in more detail. The following can be noted during this period:

- Aug: 7 total stoppages, of which 2 longer than 1 hr (07-08 Aug)
  10 flow reductions (ca. 15-30mins)
- Sept: 6 total stoppages, of 4 on 24-25 Sept.
  10 flow reductions (ca. 15-30mins)
  Increased frequency at end of month
- Okt: 18 total stoppages, of which 15 after 20 Oct
  12 flow reductions (ca. 15-30mins)
- Nov: Full shutdown on 05 Nov

Over the period August September no change in stoppage intervals are noted. However it is reported that during September sudden surges of clay were encountered, which clogged up the filter in a short period of less than half an hour (*verbal Greenwell*).

6.3 Conclusion:

Based on the available data it is likely that solids (clay) accumulated in the lee areas of a/the liner hanger(s) in the well. In September 2014 this accumulation(s) was activated into the well. This was noted at surface as sudden plugging of the filters. While reducing the flow to clean the filters part of the material is likely to have fallen into the well, resulting in a partial blockage.

7 Conclusions & recommendations

7.1 Main conclusions

Based on the observations in the above chapters the following is likely to have occurred:

- Liner coupling/collar damage in the 4 ½" blind pipe between 2470 and 2500m
  - Exact location unknown
  - Main cause high fluid velocity near uneven pipe surfaces
    - Either causing erosion or corrosion, or a combination of both
- Continuous inflow of materials into well
  - Solids settling in upper part of well (9 ⅝" casing) due to low fluid velocity
- Critical point reached September 2014
  - Filter plugging September caused by clay moving back into the stream
- Clay falling into well causing significant blockage
- Pressuring on well increases seal tightness on blockage
- Liner sealed after completing seal with LIB stomping

7.2 Recommendations

In order to prevent problems as described above it is suggested to limit the fluid velocity to 6 m/s (in line with API RP 14E). Therefore it is recommended to:

- Maximize ID of tubing to reduce flow velocity
  - Increase OD as well to prevent reduction of wall thickness

In addition it is recommended to remove edges and uneven surfaces from the inside of the well bore as much as possible. Therefore it is recommended to:

- Use internal flush casing connections
  - Remove uneven surfaces as casing collars

No changes in material grade are suggested as the erosion/corrosion effects are considered to be local at the casing collars, while the pipe body remains unaffected.

In addition the following actions are suggested to be undertaken:

- Perform fluid analyses at various stable flowrates
  - Monitor fluid content vs. flowrate to gauge effects of flow velocity on well

Appendix I

Notitie onderzoek naar een klei monster in HON-GT-01 ST1

GEOCONSULTANTS
PANterra

Notitie onderzoek naar een klei monster in HON-GT-01 ST1.

Door Anne A. Van de Weerd (PanTerra) en Dirk Munsterman (TNO).

4 februari 2015.

PanTerra Project G1156

Analyse en conclusie

Dirk Munsterman van TNO heeft een snelle palynologische analyse van het klei monster uitgevoerd dat Ted Zwinkels (Greenwell Westland) ons vorige week toestuurde. Het monster is afkomstig uit de verstopte put HON-GT-01ST1. De top van de verstopping is op 2422 mAH.

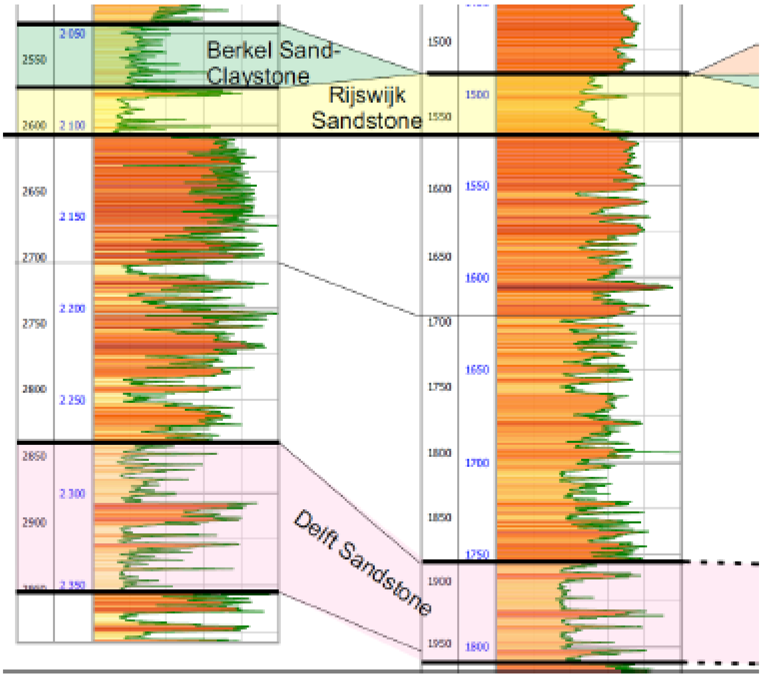
Het klei monster wordt gedomineerd door een enkel dinocysten genus, t.w. *Subtilisphaera*. Wat er in HON-GT-01ST1 gevonden is, is vergeleken met de sectie zoals bekend van de boring vandenBosch -4 (Munsterman 2012). In VDB-04 komt dit genus in deze dominantie voor in een klei sectie van 30 m dik (Monster/interval 1570-1600 in vandenBosch-4) net onder de Rijswijk Zandsteen (zie Figuur 1 en 2) .

In HON-GT-01ST1 is de basis van de Rijswijk op 2466m AH, de 7" casing shoe is op 2471 m AH, dat is 5 m onder de basis van de Rijswijk. Als we aannemen dat het interval met het gevonden dinocyst acme van ongeveer gelijke dikte is als dat in VDB-05 dan moet het kleimonster de put zijn binnengekomen tussen de casing shoe (2471m AH) en ongeveer 2500 m AH.

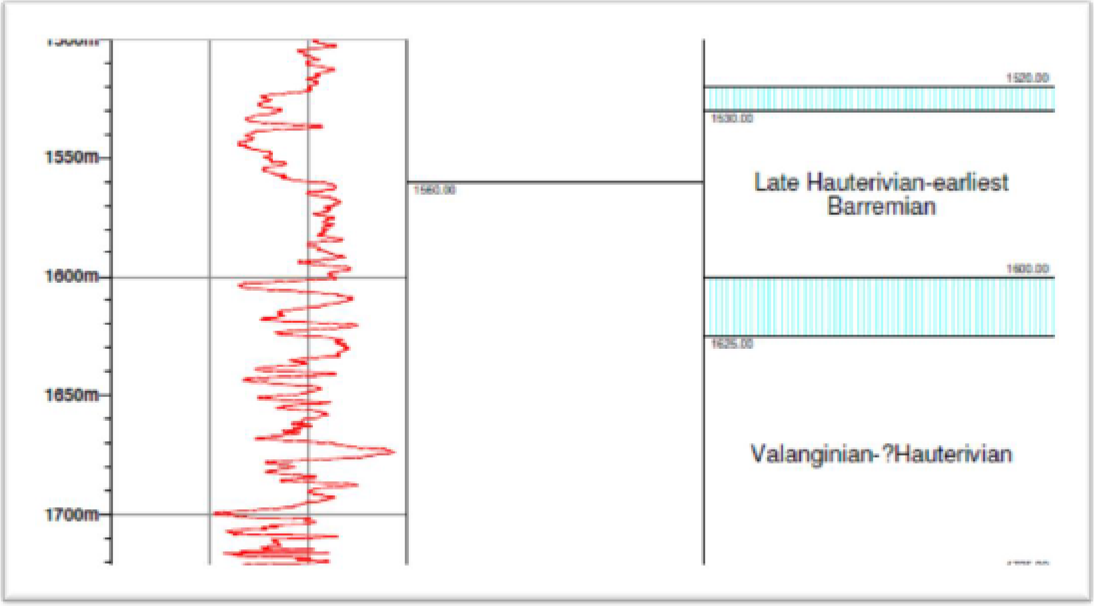
Dit leidt tot de conclusie dat oorzaak van het verstoppingsprobleem waarschijnlijk niet gezocht moet worden in de wire-wrapped screens, maar in een opening in de blind pipe net onder de Rijswijk en waarschijnlijk net onder de 7" casing shoe, mogelijk in een joint.

Referenties

Munsterman, D.K., 2012, De resultaten van het palynologische onderzoek naar de ouderdom van de Onder Krijt successie in boring Van den Bosch-04 (VDB-04), interval 925-2006 m, TNO rapport , TNO-060-UT-2011-02200/B.



Figuur 1. Twee putten met de Rijswijk- Rodenrijs en Delft. De linker put is PNA-GT-03, de rechter put is VDB-04. De kolom met dieptes in zwart (links) = measured depth AH, in blauw (rechts) is TVD. Het monster van HON-GT-01ST1 komt overeen met wat is gevonden in VDB-04 in het interval tussen de basis van de Rijswijk Sandstone en 1600m AH.



Figuur 2. Gedeelte van de GR log van VDB-04 van de Appendix van Munsterman (2012). De basis van de Rijswijk is hier op 1560 m. Het interval met de gevonden microfossielen is van 1570 tot 1600m.