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Nederlandse Aardolie Maatschappij

Second technical evaluation of Twente water injection wells TUB-7, TUB-10, ROW-7 and ROW-9

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Document History and Version Comments

Version	Issue Date	Document Number	Remarks
1	November 2020 (Submitted Jan-2021)	EP202012203362	1st Version issued for use
2	May 2021	EP202012203362	Update to address questions and remarks from Staatstoezicht op de Mijnen

Nederlandse publiekssamenvatting

Sinds 2011 injecteert NAM productiewater, afkomstig van de oliewinning in Schoonebeek, in lege gasvelden in Twente. In dat jaar hervatte NAM de olieproductie in Schoonebeek, waar sinds medio jaren ’90 geen olie meer werd geproduceerd. Voor deze activiteiten zijn diverse vergunningen verleend door verschillende overheden. Voor de waterinjectielocaties in Twente zijn specifieke vergunningen verleend door de provincie Overijssel en het ministerie van Economische Zaken. In deze vergunningen is een voorschrift opgenomen dat NAM zes jaar na aanvang van de waterinjectie een uitgebreide evaluatie diende uit te voeren naar de waterinjectie-activiteiten en de effecten daarvan op de boven het reservoir gelegen afsluitende lagen. Voor enkele putten werd de eerste evaluatie reeds na 3 jaar gedaan, in 2014/2015. Dit rapport presenteert de resultaten van een tweede evaluatie voor deze putten, 6 jaar sedertdien.

Het productiewater dat vrijkomt bij de oliewinning in Schoonebeek wordt geïnjecteerd in de diepe ondergrond in een drietal leeg geproduceerde gasvelden in Twente. De oude gasreservoirs waar op dit moment water in geïnjecteerd wordt bestaan uit kalksteenlagen waarin van nature barsten in zitten die ervoor zorgen dat de doorlaatbaarheid van dit gesteente hoog is. De kalksteenlagen worden aan de boven en onderkant begrensd door een laag anhydriet, een gesteentesoort dat geen gas of water doorlaat en niet in water oplosbaar is. Onder en boven deze anhydrietlaag zit een dikke niet doorlaatbare laag steenzout. De combinatie van een anhydriet en steenzoutlaag vormt een zeer goede afdichting die in het verleden ervoor gezorgd heeft dat het gas gedurende miljoenen jaren in de kalksteenlagen opgeslagen kon blijven en er nu voor zorgt dat het productiewater op een veilige manier in de diepe ondergrond opgesloten blijft.

Naar aanleiding van een uitgebreide Milieu Effect Rapportage (MER) zijn vergunningen afgegeven op basis van een verwachting dat al vrij snel na de start van de olieproductie in het Schoonebeek olieveld ongeveer 12,500 m^3/d productiewater geïnjecteerd zou gaan worden In werkelijkheid is de hoeveelheid water die is geïnjecteerd veel minder (4000-5000 m^3/d), omdat er minder olie is geproduceerd uit het Schoonebeek olieveld dan oorspronkelijk verwacht.

In januari 2011 is gestart met waterinjectie. Na viereneenhalf jaar, in juni 2015, is de injectie gestopt, nadat door NAM werd vastgesteld dat een veilig en verantwoord transport van het injectiewater door de watertransportleiding naar Twente niet meer gegarandeerd kon worden. Als gevolg hiervan is begin 2016 deze bestaande transportleiding gerepareerd middels een nieuwe 8 inch kunststofleiding die door de bestaande 18 inch leiding heen werd getrokken. In augustus 2016 was de vernieuwde kunststofleiding gereed voor gebruik en is de oliewinning in Schoonebeek en de waterinjectie in het Rossum-Weerselo veld medio september weer opgestart.

Conform het Waterinjectie Management Plan, dat onderdeel uitmaakt van de verleende vergunning, is een uitgebreid inspectie- en controleprogramma uitgevoerd voor diverse waterinjectieputten. Conform de voorschriften uit deze vergunning zijn voor vier waterinjectieputten (TUB-7, TUB-10, ROW-7 en ROW-9) de resultaten geëvalueerd over de afgelopen periode van zes jaar waterinjectie. Dit rapport bevat een gedetailleerde evaluatie van deze inspecties en testen en dient beoordeeld te worden door het bevoegd gezag. Tijdens de evaluatie is gekeken naar

- het injectiegedrag (injectiedruk en injectiviteit; dat is de hoeveelheid water die per eenheid van druk wordt geïnjecteerd),
- de huidige reservoirdruk in vergelijking met het model,
- de integriteit van de stalen verbuizingen in de put,
- de integriteit van de injectiebuis.

Gedurende de periode dat water is geïnjecteerd tussen januari 2011 en oktober 2020 zijn de injectiedrukken, als gemeten aan het oppervlak, voor alle putten nooit hoger geweest dan de in de vergunning opgenomen druklimieten (zie tabel 1 van het Waterinjectie Management Plan). Deze druklimieten zijn ingesteld met als doel de integriteit van de afsluitende lagen boven en onder de reservoirs te garanderen.

De reservoirdruk in putten TUB-7, TUB-10, ROW-7 en ROW-9 is grofweg in lijn met de model verwachting. Er zijn er geen overschrijdingen geconstateerd van de drukken zoals in de vergunningen zijn vastgelegd. Echter, de hoeveelheid water die tot nu toe is geïnjecteerd, is nog steeds te gering om een betrouwbare voorspelling te maken van de uiteindelijke opslagcapaciteit op basis van de toename van de reservoirdruk. Daarom is er op dit moment geen aanleiding om de reservoirmodellen aan te passen.

De injectiviteit in de reservoirs wordt bepaald door middel van een zogenaamde ‘step-rate’-test (SRT), een test waarbij op diepte van het reservoir de injectiedruk wordt gemeten terwijl de injectiesnelheid stapsgewijs wordt verhoogd. Deze testen tonen volgens de verwachtingen aan dat het water vooral wordt opgenomen in een bestaand (natuurlijk) netwerk van barsten in deze ondergrondse formatie. De waterinjectie in de putten ROW-7, TUB-7 en TUB-10 wordt beschouwd als erg goed (tot 2000 m^3 per dag), terwijl deze in put ROW-9 (tot 1000 m^3 per dag) matig tot goed is. De SRT’s toonden aan dat er geen nieuwe barsten worden gevormd als gevolg van de injectie. Daarom is de aanpak gewijzigd en gedocumenteerd in het geactualiseerde Water Injectie Management Plan. De SRT’s zijn gestopt. Als er op basis van oppervlakte data (injectie druk en snelheid) aanwijzingen worden gevonden dat dit verandert, kunnen de SRT’s weer worden hervat.

In de MER en vergunningsaanvragen is destijds de nodige aandacht besteed aan het mogelijk oplossen van de afdekkende steenzoutlaag indien deze laag in aanraking zou komen met het injectiewater en het effect daarvan op bodemdaling. De MER concludeert dat deze zoutlagen niet of nauwelijks zullen oplossen in het injectiewater, echter om hierover aanvullende inzichten te verkrijgen is besloten uitgebreide modelleringen uit te voeren. Op basis van deze uitgebreide modelleringen is aangetoond dat de conclusie uit de MER juist is[1]. De conclusies van deze rapporten zijn beoordeeld door Staatstoezicht op de Mijnen en diverse buitenlandse instituten. Deze reviews wijzen uit dat er een groot aantal aanwijzingen is dat injectie van water niet zal leiden tot oplossen van zout of aardbevingen. In het theoretische geval dat injectiewater langs de buitenzijde van de stalen verbuizing van de waterinjectieput zou stromen, kan niet uitgesloten worden dat de zoutlaag dan plaatselijk aangetast wordt.

Ter voorkoming van zo’n situatie worden verschillende preventieve metingen in de injectieputten uitgevoerd om de status van de waterinjectieputten zeker te stellen:

1. Omdat de temperatuur van het injectiewater lager is dan de temperatuur in de diepe ondergrond zullen de zones waar water in geïnjecteerd wordt iets afkoelen. Met behulp van speciale apparatuur kan zowel in als buiten de put (dus achter de verbuizing) de temperatuur gemeten worden. Indien koude plekken worden gemeten achter de verbuizing kan dit erop wijzen dat daar injectiewater heeft gestroomd en zout heeft opgelost. In een dergelijk geval zal de waterinjectie stopgezet worden en zal nader onderzoek volgen. De waterinjectie wordt dan pas weer hervat als dit veilig plaats kan vinden, hetgeen inhoudt dat het risico op lekkage als zeer laag geklassificeerd wordt of als een reparatie uitgevoerd is.
2. De kwaliteit van de cementenwand die buitenom de gehele waterinjectieput zit, wordt gemeten met behulp van zogenaamde Cement Bond Logs (CBLs). Mocht blijken dat er kwaliteitsverschillen zijn in het cement, dan zou dit de mogelijkheid kunnen bieden voor stroming van injectiewater achter de verbuizing van een injectieput. Water wordt slechts daar geïnjecteerd waar geen aanleiding is om te vermoeden dat injectiewater achter de verbuizing in contact kan komen met zout.
3. De integriteit van de verbuizing wordt gecontroleerd door de wanddikte van de verbuizing te meten. Dit wordt gedaan door middel van een gedetailleerde diameter (of caliper) meting die afwijkingen in de wanddikte van de buis kan detecteren.

De temperatuurmetingen die in alle waterinjectieputten zijn uitgevoerd geven aan dat het water op de juiste plaats van het reservoir wordt geïnjecteerd en dat het steenzout niet aan het injectiewater is blootgesteld. Uit CBLs (zie punt 2) en caliper-metingen (zie punt 3) blijkt dat de waterinjectieput- en cementconditie goed zijn en dat het hierboven beschreven mogelijk risico van het oplossen van de zoutlaag verwaarloosbaar is.

Betreffende de integriteit van de waterinjectieputten kan worden vastgesteld dat alle gemeten drukken binnen de in de vergunningen opgenomen druklimieten zijn gebleven. In alle waterinjectieputten zijn de wanddiktes van de injectiebuizen meer dan voldoende om de maximale verwachte injectiedruk te weerstaan. In waterinjectieput ROW-9 zijn zogenaamde putstimulaties uitgevoerd, die mogelijk invloed hebben gehad op de wanddikte. Echter de huidige wanddikte voldoet nog aan alle vereisten zodat de waterinjectie ook in deze putten veilig en verantwoord is.

Geconcludeerd mag worden dat alle in de vergunning genoemde inspectie- en testprogramma’s (beschreven in het Waterinjectie Management Plan) volgens plan zijn uitgevoerd. Hierbij is aangetoond dat de in de vergunning genoemde beheersmaatregelen van het waterinjectie-programma goed werken en dat alle waarborgen voor een veilig en verantwoord opereren van de waterinjectieputten aanwezig zijn.

[1] Nadat SodM, vanuit haar rol als toezichthouder, in 2011 om een risicoanalyse van het waterinjectie proces had gevraagd, heeft NAM in 2014 en 2015 vier technische rapporten geleverd over de risico’s van het eventueel oplossen van zout bij het reservoir en naar de kans op het optreden van geïnduceerde aardbevingen.
SodM heeft deze rapporten voorgelegd aan onafhankelijke experts in Duitsland, Frankrijk en de Verenigde Staten, en hen om een review gevraagd. Deze reviews zijn in het voorjaar van 2016 ontvangen en wijzen uit dat de studies door NAM goed zijn uitgevoerd. Er is een groot aantal aanwijzingen dat de huidige injectie van het productiewater niet zal leiden tot oplossen van zout of aardbevingen.
(http://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

Management summary

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM-1, TUM-2, ROW-2, ROW-3, ROW-5, ROW6 and TUB7) to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is required to evaluate and report the water injection process and activities and the effects on the confining cap rock every 6 years. From an environmental point of view, the key concern is the mitigation of the risk for contamination of shallow aquifers due to loss of containment. The technical evaluation therefore focusses in particular on the effect of water injection on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir. For some wells, the first evaluation was already carried out after 3 years, in 2014/2015, Reference [1]. This report presents the results of a second evaluation for these wells (ROW-7, ROW-9, TUB-7 and TUB-10), 6 years since.

Main conclusions from the 6-yearly technical evaluation are:

- Wells ROW-9, TUB-7 and TUB-10 are suspended and are no longer used for water injection. Evaluation of their injection history proved good integrity.
- Well ROW-7 (currently hooked up and injecting) is in reasonable condition and can be used for future water disposal.
- The monitoring programs provide an appropriate early detection and protection framework to guarantee the integrity of the wells and reservoirs and thus a safe and responsible operation. More specific conclusions are listed below.

From static pressure gradients (SPG's), surface injection pressures (THPi) and injection and fall-off tests the following is concluded, respectively:

- The actual average pressure in the various reservoirs is still significantly lower than the original reservoir pressure for all wells.
- During the entire injection period, the surface injection pressure remained well below the set injection pressure limit for the wells. Hence, for all wells the maximum bottom hole pressure during injection has never exceeded the minimum in-situ stress of the confining layers (ZEZ-Halite for both the ROW and TUB wells).
- The cumulative amount of water injected to date is too small to make an accurate prediction of the final storage capacity based on the pressure. Therefore, the available data do not yet warrant an adjustment to the reservoir models.
- The step-rate test (SRT)-plots derived from the injectivity tests all show a linear trend indicating injection into existing natural fractures in the fractured Zechstein-Carbonate reservoir, which means that injection occurs below fracturing pressure.
- Since injection does not take place under fracturing conditions, determination of minimum horizontal stress from fall-off surveys cannot be done as intended, and fall-off tests for that purpose are no longer mandatory[2]. Pressure transient analysis suffers from large wellbore storage effects, and only indicative results for permeability (fracture spacing) are obtained.
- Conducted step-rate tests appear to yield poor quality data as in every test it takes progressively more time to achieve the required downhole pressure stabilization. Because the wellbore does not completely fill up to surface, it is not even possible to determine from the surface pressures during the tests whether stable downhole pressure was achieved.

Extensive studies have been carried-out regarding Halite dissolution when exposed to injection water and its effect on subsidence[3,4]. These studies have been independently reviewed by University experts under auspices of State Supervision of Mines[5]. From Halite dissolution modelling it was concluded that potentially this can only occur near the injection well. Hereto, a leak in the production casing in combination with a poor cement bond behind casing must occur simultaneously in order to allow injection water to directly flow past the Halite formation. Temperature surveys, cement bond logging and casing caliper surveys have been executed to check if injection water potentially exposes the ZEZ-Halite layers. From the logging the following is concluded:

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2 Staatstoezicht op de Mijnen – Uw addendum op het evaluatierapport Twente waterinjectie, kenmerk 15137190. EP201510202648, October 2015

3 Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal. EP201310203080, December 2014

4 Subsidence caused by Halite dissolution due to water injection into depleted Carbonate gas reservoirs encased in Halite. EP201310204177, December 2014

5 These studies have been independently reviewed by independent University experts under auspices of the Dutch Mining Regulator (State Supervision of Mines). All the conclusions and findings of the studies were supported by both the experts and the regulator. (https://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

- Downhole temperature surveys indicate that injection is restricted to the targeted Zechstein-Carbonate reservoirs.
- The risk for Halite dissolution is perceived negligible in all logged wells. Casing caliper surveys and cement bond logs show good cement and casing quality across the confining Halite seal layers. There is no indication for potential leak paths behind casing.

Evaluation of the well and tubing integrity results in following conclusions:

- Tubing strength calculations show that tubing integrity exceeds the minimum requirements for safe operations. All wells show enough wall thickness (degree of pitting ≤ 60%) to withstand maximum injection pressures. No tubing leaks are detected.
- During the current evaluation period all A-, B- and C-annulus pressures have remained below their Maximum Allowable limit (MAASP).
- Pressure data demonstrate full pressure isolation between the tubing, A-annulus and B-annulus.

1 Introduction

In compliance with the various water injection permits that were granted in 2010 for the 7 locations[6] to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is requested to evaluate and report the water injection process and activities every 6 years. From an environmental point of view, the key concern is the mitigation of the risk for contamination due to loss of containment. The technical evaluation therefore will, in particular, focus on the effect of water injection on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir. By ensuring containment of injected water in the target reservoir, migration of injected water to surface is avoided.

The integrity of the cap rock will be maintained when:

- the downhole injection pressure at the depth of the cap rock does not exceed the fracturing pressure of the caprock
- no significant near-wellbore Halite dissolution occurs

Here to, relevant parameters such as the surface injection pressure and rate, actual injection pressure at top reservoir and injection tubing and casing wall thickness have been closely monitored and measured in accordance with the Water Injection Management Plan (WIMP), References [2]. The results of the extensive monitoring plan and conclusions are shared in this report. In addition, overall well integrity status of the various injectors is addressed.

As specified in the WIMP, a technical evaluation is done every six years from start injection. However, the first technical evaluation was carried out already after 3 years in 2014/2015. The study comprised six wells (ROW-3, -4, -7 and -9 and TUB-7, -10) that were expected to show faster pressure increase with respect to connected reservoir volume and planned injection rate. A second evaluation was done in 2017 for injection wells TUM-1, TUM-2, TUM3 and ROW-2, ROW-3, ROW-4 and ROW-5. The evaluation reports for these wells were shared with the regulator (Ministry of Economic Affairs/SodM), References [1] and [3]. This current report provides the second six-yearly review for the remaining wells from the first set.

It can be observed from the cumulative production in Figure 1-1 that no additional injection took place in to TUB-7 since the January 2015 analysis, Reference [1], and only a couple of months injection into TUB-10 and ROW-9. Injection stopped in June 2015 when it was discovered that the water export pipeline was no longer fit-for-purpose due to integrity issues. As a result, the Schoonebeek field was closed in at 6/6/2015. The water export pipeline was restored in August 2016 after the installation of a smaller 8” diameter flexible composite pipe (FCP) inside the existing 18” water transport pipeline. Due to the smaller inside diameter of the FCP, the water transport capacity to Twente was reduced. Consequently, the full water injection capacity can currently not be utilized. Since the restart, injection is limited to locations ROW-2, ROW-3 and ROW-5, which are connected with corrosion resistant cladded pipelines. The injection wells on these locations (wells ROW-2, ROW-4, ROW-5 and ROW-7) have a total potential injection capacity of 5500 m^3/d. Well ROW-3 remains available for future water injection. Wells , ROW-9, TUB-7 and TUB-10 are suspended with plugs installed in the wellbore. The TUM wells are listed for permanent decommissioning.

[6] Injection locations: TUM-1, TUM-2, ROW-2, ROW-3, ROW-5, ROW6 and TUB7

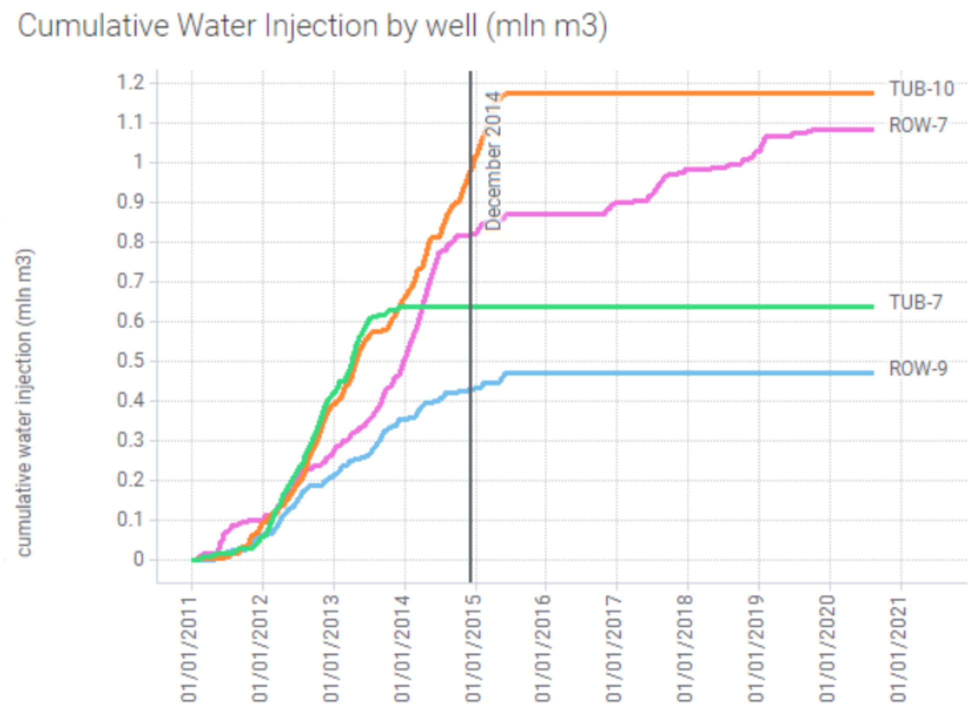

Figure 1-1: Cumulative injection for ROW-7/9 and TUB-7/10. Previous 6-yearly review indicated (December 2014)

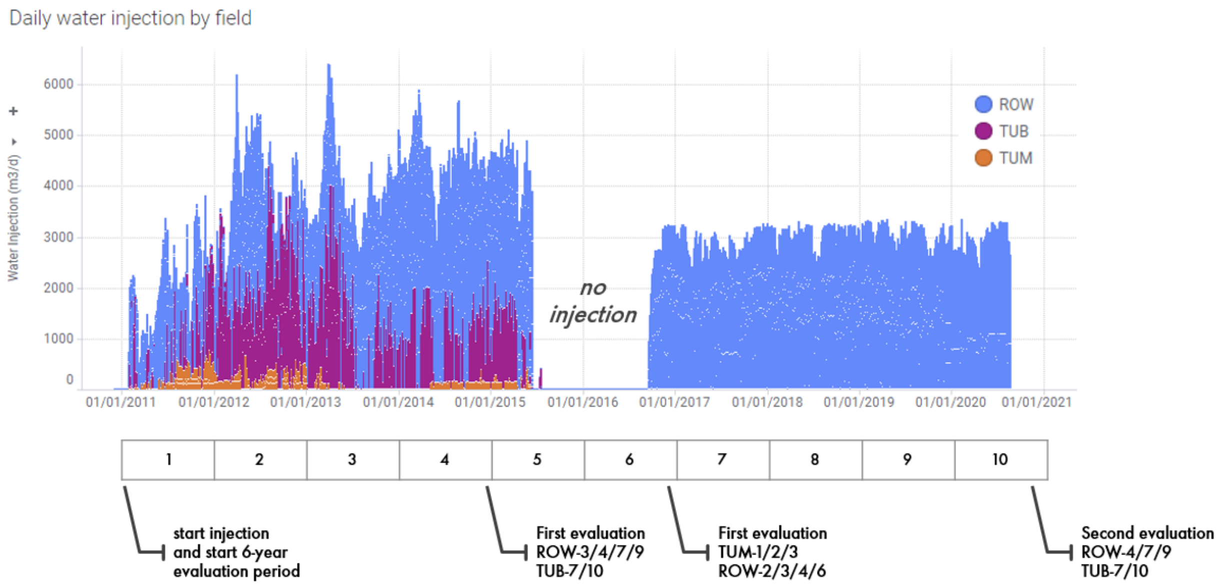

Figure 1-2: Twente water injection timeline

2 Description of water injection system

2.1 Injection system

The produced water is separated from the Schoonebeek Oilfield production stream at the Central Treatment facilities (CTF). Once separated, the water is cooled to 40 °C. Subsequently, corrosion inhibitor is added after which the water exits the CTF at a flowrate of around 3,000 m^3/d and at a pressure of about 35 bars. The initial produced water composition was similar to that of the Schoonebeek formation water. However, with time, the ion content is decreasing due to dilution by the condensed 'sweet' water that originates from the steam injected into the Schoonebeek reservoir. The produced water contains <100 ppm oil and <100 mg/l suspended solids (>5 µm), the actual values are reported annually, e.g. Reference [4].

As Figure 2 shows, the produced water is transported from the CTF to the De Hulte scraper station via a 17 km, 14" GRE pipeline. This new pipeline has a maximum capacity of 15,500 m^3/d and a maximum design pressure of 40 bars. At De Hulte the new 14" GRE pipeline is connected to the 45 km, 18" Twente trunk line, which was previously used to evacuate the sour wet gas from the Twente wells. This trunk line was used to transport the injection water to depleted gas fields in Twente. Due to integrity issues of this pipeline, water injection was stopped in June 2015 and, consequently, oil production and steam injection had to be stopped too. The trunk line was repaired by installing an 8" flexible composite pipe (FCP) inside the existing 18" pipe. The installation was completed in August 2016.

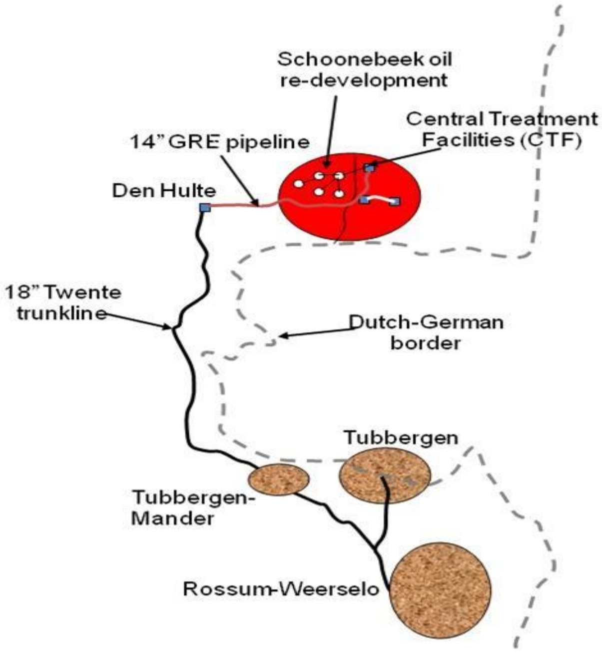

Figure 2-1: Schematic representation of water injection system within Schoonebeek Oilfield production system

The transported water arrives at the Twente well sites at a pressure of approximately 5 bars and a maximum temperature of 30 °C. At every injection well a skid with a horizontal multistage centrifugal pump (MCP) is installed. This MCP contains a variable speed drive, which allows the pump to be operated at the required rates and pressures.

In Twente the Schoonebeek production water is re-injected into depleted gas fields. These fields are the Tubbergen-Mander (TUM), Tubbergen (TUB) and Rossum-Weerselo (ROW) fields. Significant gas volumes were produced from these fields in the past providing a significant water storage capacity. Injection in fields TUB and TUM was ceased mid-2015. Since the repair of the trunk line, only the ROW field is used for water re-injection.

2.2 Injection reservoir

The wells under review in this report all inject into the naturally fractured Zechstein Carbonate formation. The reservoir seal is provided by the overlying Zechstein salt (Halite) layers. All wells are connected to two Zechstein Carbonate reservoirs, namely the ZEZ2C and ZEZ3C. These reservoirs are separated at both the top and base from the salt by laterally continuous Anhydrite layers. These Anhydrite layers are several meters thick (2-10 mTV), impermeable and essentially insoluble (the solubility of Anhydrite in water at reservoir conditions is a factor 1000 less than that of Halite).

3 Injection performance - Actual versus Plan

In this chapter the actual water injection between 2011 and 2020 is discussed and compared to the plan as it was presented in the water injection FDP, Reference [5].

In the Schoonebeek FDP it was assumed that during the first 3 years of operations the water injection would be at a plateau rate as high as 12,500 m^3/d. In reality, the actual total injection rate was in the order of 4,000-5,000 m^3/d, significantly below what was assumed in the FDP (Figure 3-1). The difference between actual and expected injection rates in the FDP is due to lower production rates of Schoonebeek oilfield production wells. Since the water export pipeline repair, the maximum water export capacity is restricted to 3300 m^3/d.

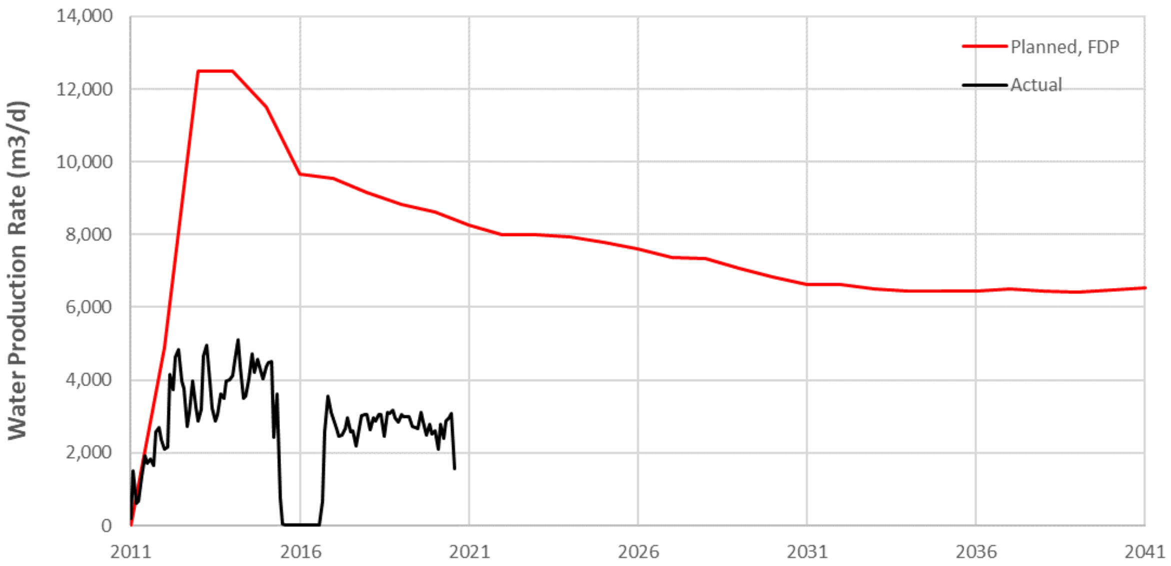

Figure 3-1: Actual water injection rates compared to planned in FDP

The annual volumes of water injected in the water injection wells from start of injection to date is given in Figure 3-2. Table 3-1 lists the total cumulative water volume that has been injected per location from the start of injection in Q1 2011 until October 2020. Because of the lower than expected water injection rate, the total injected volume at all locations is still much lower than the volumes allowed according to the water injection permit for each location.

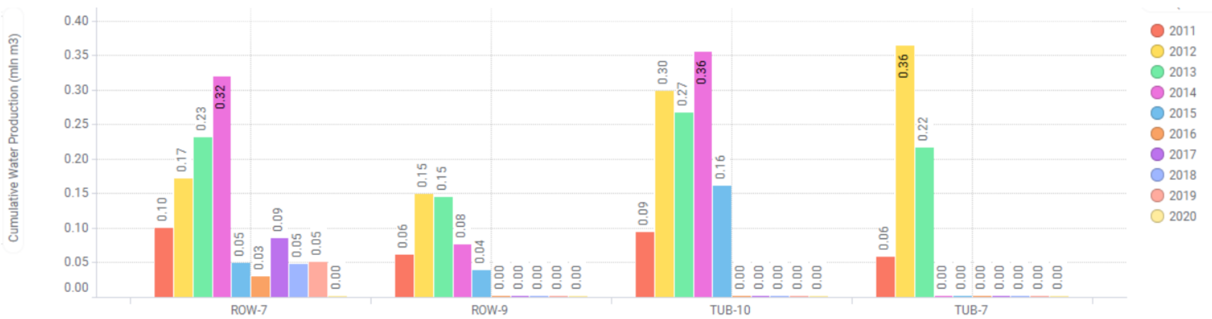

Figure 3-2: Cumulative injective volume per year for the evaluated water injection wells (up to 19/8/2020)

Table 3-1: Cumulative injected water volume per location until October 2020 in comparison with the allowed volume according to the water injection permit for each location[7].

	location	ROW-2		ROW-3		ROW-5	ROW-6	TUB-7	
	well	ROW-2	ROW-7	ROW-3	ROW-4	ROW-5	ROW-9	TUB-7	TUB-10
year	2011	0.076	0.101	0.015	0.055	0.041	0.079	0.060	0.100
	2012	0.062	0.171	0.011	0.060	0.091	0.150	0.364	0.299
	2013	0.255	0.231	0.011	0.135	0.063	0.145	0.216	0.267
	2014	0.536	0.318	0.005	0.084	0.137	0.076	0.006	0.380
	2015	0.174	0.049	0.004	0.068	0.094	0.039	0.000	0.161
	2016	0.120	0.030	0.000	0.092	0.042	0.000	0.000	0.000
	2017	0.524	0.085	0.000	0.223	0.145	0.000	0.000	0.000
	2018	0.497	0.047	0.000	0.324	0.197	0.000	0.000	0.000
	2019	0.395	0.062	0.000	0.421	0.159	0.000	0.000	0.000
	2020*	0.000	0.031	0.000	0.532	0.257	0.000	0.000	0.000
	cumulative by well	2.637	1.126	0.046	1.994	1.227	0.488	0.646	1.206
	cumulative by location	3.763		2.040		1.227	0.488	1.852	
	permitted cumulative	19.100		7.800		6.590	1.610	9.800	

*) 2020 data until October

[7] According to "Voorschriften Wet Milieubeheer" in granted Water injection Permit

4 Water injection and integrity of reservoir confining seals

4.1 Introduction

During produced water reinjection, it is important that the water is injected and contained within the targeted injection reservoir and that any possible upward migration that could result in exposure and contamination of shallow aquifers is prevented. It is essential therefore that the containment layers directly above and below the injection reservoir and the confinement layers surrounding the containment layers are not affected by the injection process. Especially, fracture propagation and/or migration of injected water into the confining layers must be prevented. The depleted gas reservoirs in Twente, in which water is injected, are mainly Zechstein Carbonate reservoirs (ZEZ2C and ZEZ3C) with an existing natural fracture network. The containment layer is formed by a water insoluble Anhydrite layer that is surrounded by Halite, which then is the sealing confinement layer.

To ensure integrity of the confining layers, the following monitoring and controls are in place:

- **Average reservoir pressure**

  Average reservoir pressure should not exceed the original pressure, i.e. the reservoir pressure prior to gas production. At the original reservoir pressure, the confining layers have sealed the gas bearing reservoirs for millions of years. Hence, it is not realistic that at lower reservoir pressure injected water (which is much heavier than gas) will migrate upwards through these layers. The pressure at reservoir depth has been measured every year during the injection period so far.

- **Maximum THT**

  The injection pressure at surface is constrained to avoid that the injection pressure downhole exceeds the minimum in-situ stress of the sealing confinement layer. The maximum tubing head injection pressures are, therefore, calculated based on the fracture pressure gradient of the reservoir seal:

$$THPi_{max} = F.G._{seal} \times TVD_{bottom\ seal} - P_{hyd}$$

  in which:

  - $THPi_{max}$ = the surface injection pressure limit (bar)
  - $F.G._{seal}$ = the fracture gradient of the disposal reservoir confining layer (bar/m)
  - $TVD_{bottom\ seal}$ = the true vertical depth at the bottom of the reservoir seal, i.e. at top disposal reservoir
  - P_{hyd} = hydrostatic pressure (assuming water density of 1.05 sg)

  Note that in this equation the frictional pressure drop in the tubing is ignored, to apply conservatism to the $THPi_{max}$ calculation. In addition, it is assumed that the entire wellbore is filled with water[8].

- **Injection under fracturing conditions**

  Propagation of the existing natural fracture network in the Zechstein Carbonate reservoir or propagation of (an) induced fracture(s) in the Carboniferous Sandstone was surveyed by the execution of injection step-rate tests (SRT's) and pressure fall-off (FO) tests. Plotting of the stabilized bottomhole pressure (FBHPi) as a function of the increasing injection rate gives information on the injectivity. In non-fractured reservoirs, such as the Carboniferous Sandstone reservoir, it will be evident from the change in the slope of the steprate curve that formation breakdown has occurred and/or that fracture propagation has occurred. In the naturally fractured Carbonate, a slope-change can indicate extension of the fracture network which would result in an increased injectivity.

The static reservoir pressures determined from static pressure and temperature gradients (SPTG's), the actual surface injection pressures (THPi) and the injectivity and step-rate/fall-off tests are discussed section 4.2, 4.3 and 4.4 respectively.

[8] In reality, most wells show sub-hydrostatic injection conditions, section 4.3.

4.2 Static pressure gradient surveys

To determine the local pressure for each well at reservoir depth, the well is shut-in and a pressure/temperature gauge is run in hole on wireline down to reservoir level. Subsequently, it's pulled upward to measure the pressure (and temperature) at various depths, allowing for determination of static pressure and temperature gradients (SPTG) along wellbore depth. Often, liquid levels in the wellbore can also be observed. Because the near-wellbore pressure (FBHPi) during injection is higher than the average reservoir pressure (in order to drive the water into the reservoir), the pressure that is measured with the survey is usually higher than the actual (far field) reservoir pressure. It is, therefore, important that the well is shut-in sufficiently long prior to the pressure survey to allow the pressure to equalize and approach the far-field reservoir pressure. In case the injectivity is moderate or poor and the shut-in period is short, the derived pressure at the wellbore can be higher than the average reservoir pressure

An overview of the measured downhole pressures is reported annually to SodM, e.g. Reference [4]. The expected development of reservoir pressure as a function of injected water volume was predicted prior to actual injection for each well. Hereto, the water storage capacity was determined for each well by dividing the total amount of gas produced with the original gas formation volume factor, References [6] and [7]. Figure 4-1 provides a visual comparison of the predicted reservoir pressure prediction against the actual measured downhole pressure, as a function of injected volume, a table of the measurements is included in Appendix D.

As described in Reference [8], various dynamic effects are in a complex interplay at the same time: fast transport of water through the fracture network, subsequent entering of water into the matrix rock, thereby compressing the matrix gas, mobility changes of water displacing gas in the matrix due to relative permeability effects, gravity (depending on the height of the injector on the structure, Figure 4-4 and Figure 4-5). The combination of these dynamic effects yielded a higher measured local pressures than the average reservoir pressure for wells ROW-9 and TUB-10, as can be observed from Figure 4-1.

All measured reservoir pressures are still significantly below the original reservoir pressure, which is in accordance with the cumulative injected volume of water thus far, as listed in Table 4-1 for each well. On a field level, total injection is still relatively small compared to the expected storage capacity: total Rossum-Weerselo Zechstein injection is 7.5 mln m^3 which is 22% of the total modelled capacity of 34.6 mln m^3. Proportionally, the pressure effect from the various dynamic effects is relatively large compared to the increase in the average reservoir pressure. Hence at this point in time, there is no merit in adjusting the model. Pressures trends will be continually monitored according the Water Injection Management Plan (i.e. for well ROW-7).

Table 4-1: Injected volume of water compared to modelled and permitted capacity

Location	Well	Injected volume mln m^3	Modelled capacity[1] mln m^3	Degree of filling	Permitted capacity[2] (per location) mln m^3	Capacity used (per location)
ROW-2	**ROW-2**	2.637	13.2	20%	19.1	20%
	ROW-7	1.126	2.1	54%		
ROW-3	**ROW-3**	0.046	2.2	2%	7.8	26%
	ROW-4	1.994	4.0	50%		
ROW-5	**ROW-5**	1.227	13.5	9%	6.59	19%
ROW-6	**ROW-9**	0.488	1.8	27%	1.61	30%
TUB-7	**TUB-7**	0.646	4.8	13%	9.8	19%
	TUB-10	1.206	5.4	22%		

[1] Assuming an initial gas saturation of 80%

[2] According 'Voorschriften Wet Milieubeheer' in granted Water injection Permit

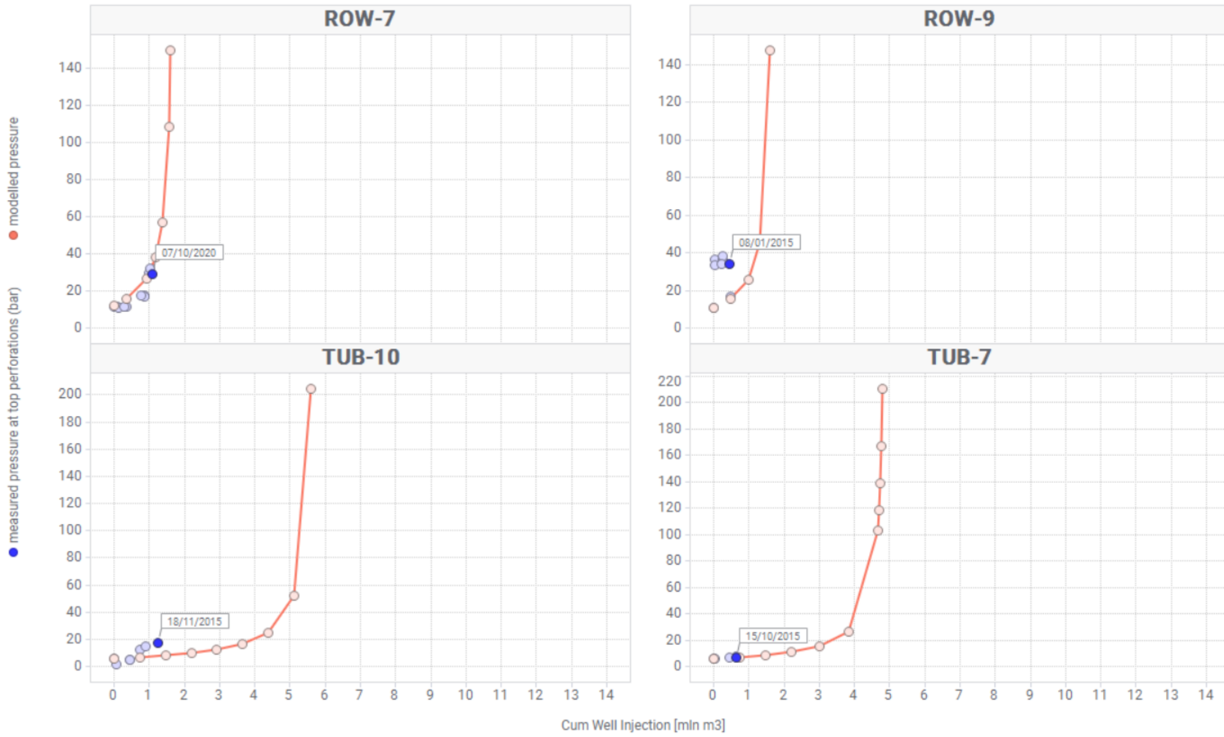

Figure 4-1: Reservoir pressure development during injection. Note: all measured bottomhole pressures have been converted to top reservoir depth of their respective wells.

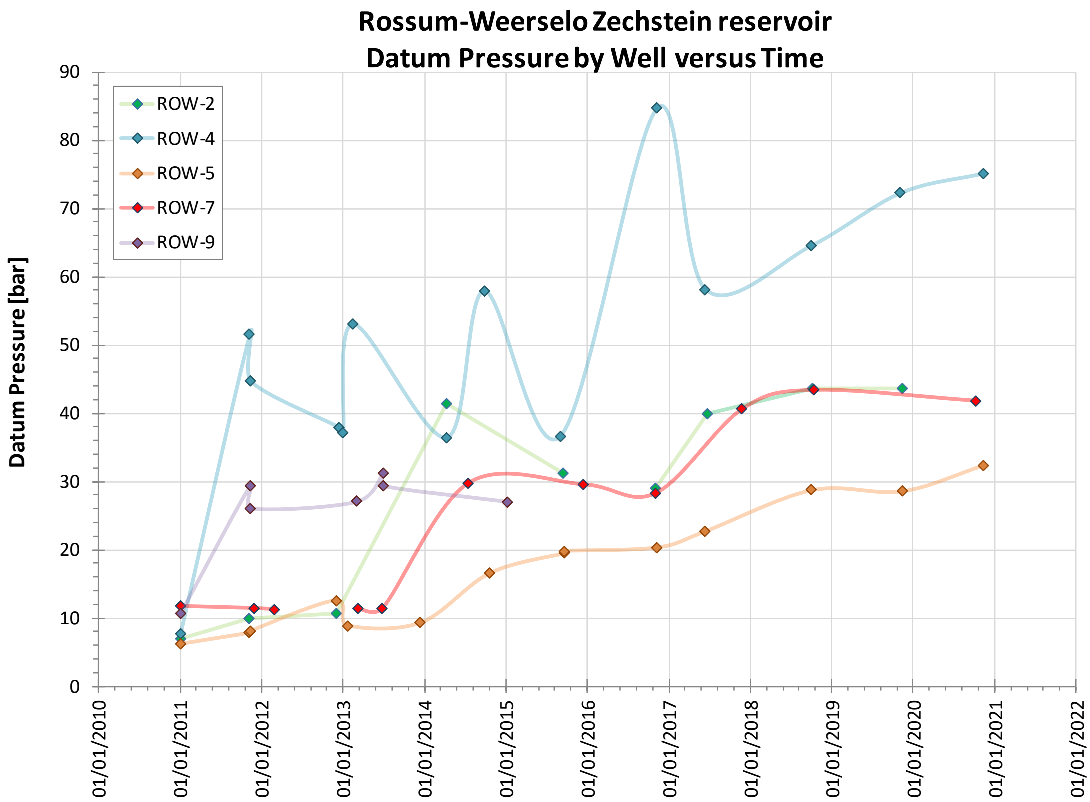

Figure 4-2: Reservoir pressures at datum for the Rossum-Weerselo Zechstein reservoir during the water injection phase as a function of time

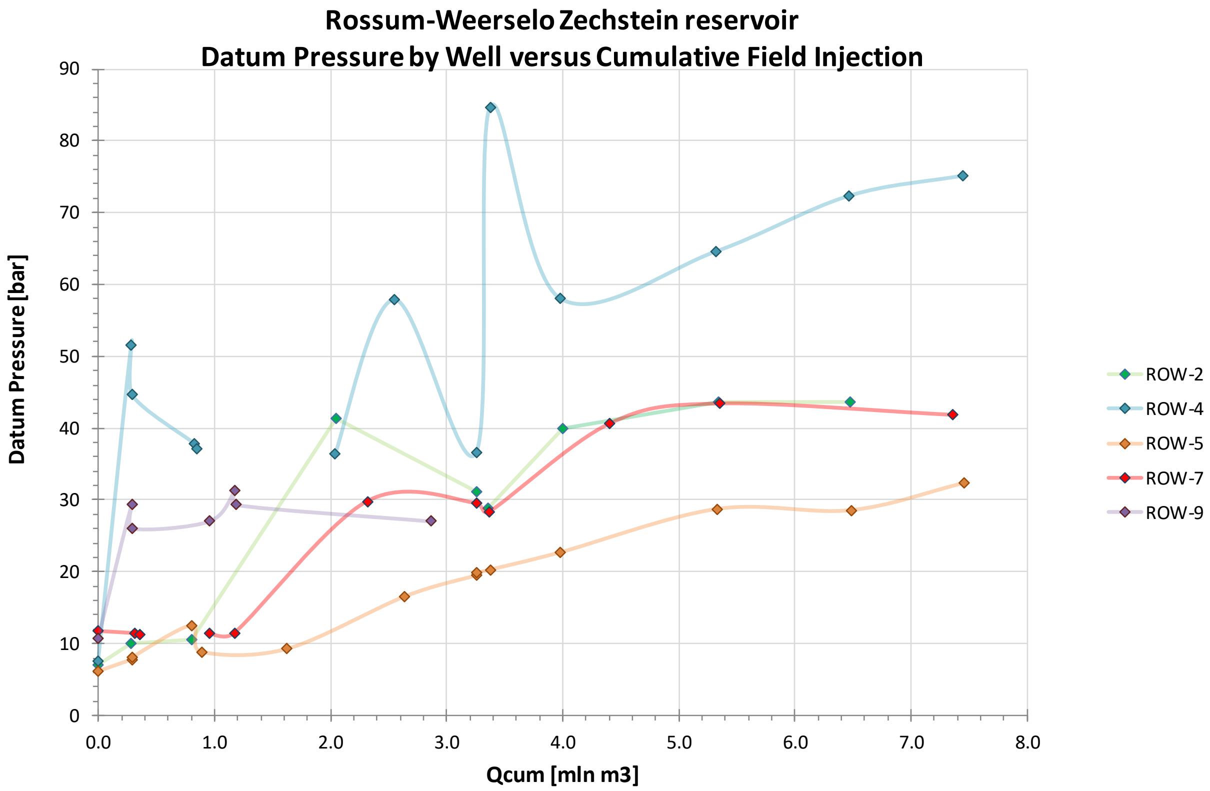

Figure 4-3: Reservoir pressures at datum for the Rossum-Weerselo Zechstein reservoir during the water injection phase as a function of the cumulative reservoir injection volume.

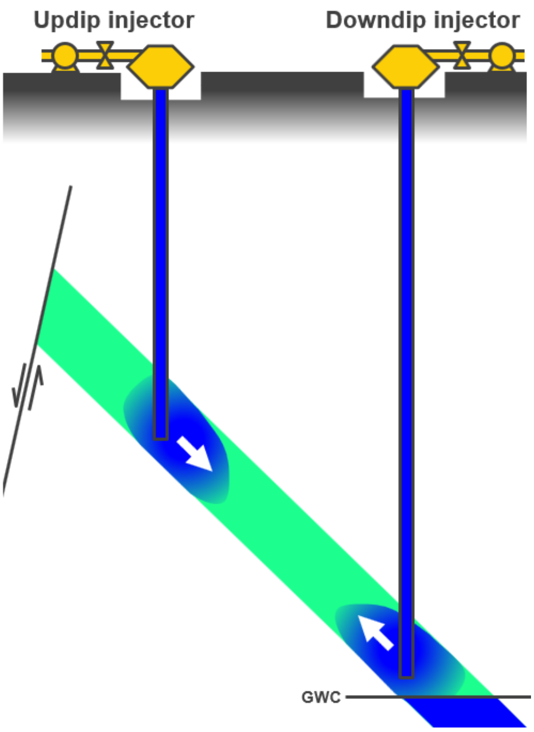

Figure 4-4: Schematic cross-section to illustrate the potential impact of gravity on required injection pressures.

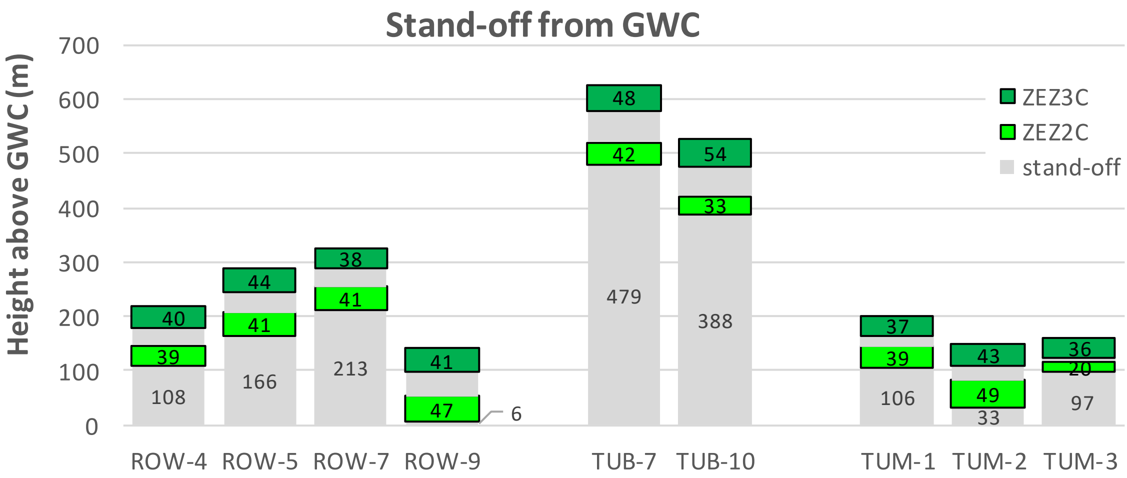

Figure 4-5: Reservoir standoff from the original Gas-Water-Contact

4.3 Injection rates and pressures

In section 4.1 the calculation is given for THPi,max to ensure integrity of the confining layers. In addition, a safety margin of 10% for the Halite and 20% for the Buntersandstein is applied to the calculated THPi limit to arrive at a maximum THPi applied in practice. To avoid that these THPi limits are exceeded, the injection pumps have been equipped with alarms and trip settings. In case the alarms are missed in the system, as a second barrier, a Pressure Safety Valve will open.

Figure 4-6 provides an overview of daily injection pressure and rates for all wells, indicating the maximum injection pressure at surface (THPi,max) as summarized in Table 4-2. It is clear that the injection pressure remained well below the set THPi-limits for the wells.

From Figure 4-6 wells ROW-7, ROW-9, TUB-7 and TUB-10 can all be seen to be sub-hydrostatic injectors: the bottomhole flowing pressure is so low that it cannot sustain a full water column up to surface. Water at surface effectively “free-falls” into the well. Consequently, the measured THPi values are only governed by the upstream pressures (showing higher pressures at higher rates due less choking upstream of the THPi measurement).

Note that occasionally, Figure 4-6 shows increasing THPi during shut-in periods. This is due to gas migrating from the gas reservoir into the well, building up a gas column in the well. For the same reservoir pressure, a lighter wellbore column yields a higher tubing head pressures.

Table 4-2: Maximum surface injection pressure, Reference [2].

well	Reservoir Depth (m)	THPi, max (bar)	Safety margin
ROW-2	1083	115	10%
ROW-3	1692	180	10%
ROW-4	1232	131	10%
ROW-5	1163	124	10%
ROW-7	1125	119	10%
ROW-9	1310	139	10%
TUB-7	1312	139	10%
TUB-10	1412	150	10%

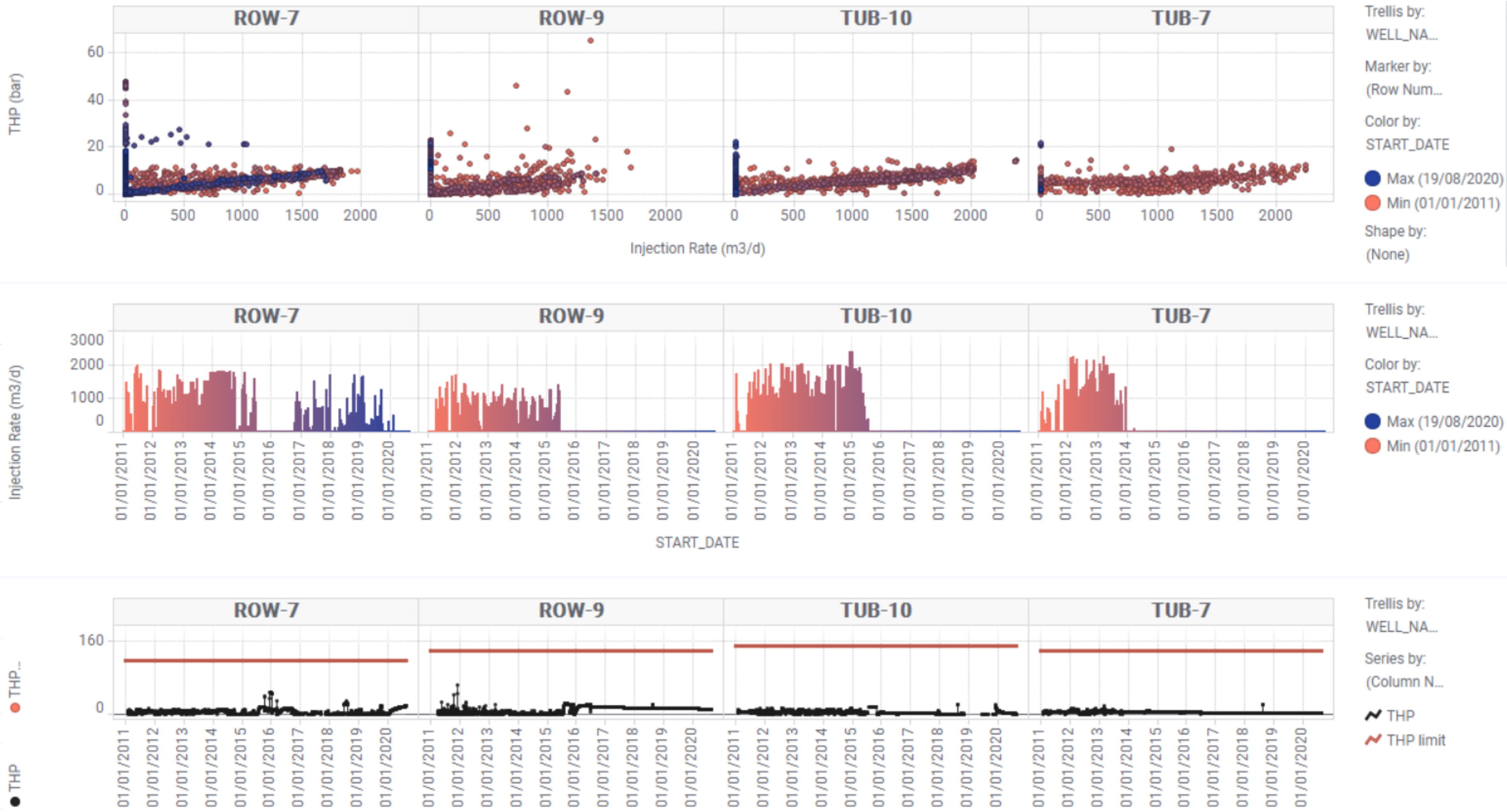

Figure 4-6: Daily tubing head pressure with THP limit, daily injection rates, and cross-plot of THP versus injection rate for wells ROW-7/9 and TUB-7/10, colored by date. Note that the flow rates in the plots are daily averages: when a well was not flowing the full day, the day average rate in the plot is lower than the actual flowing rate when the well was online.

4.4 Well injectivity

4.4.1 Step-rate tests

In the FDP, Reference [5], it was expected that water injection would occur at fracturing conditions, given the low reservoir pressure and consequently, low fracturing pressure of the reservoir (i.e. σ_h,min). However, the water is injected into depleted Zechstein Carbonate reservoirs containing an extensive pre-existing fracture network. These natural fractures are filled with the injected water without creating new fractures or propagating existing fractures. They provide high permeability conduits that bring the injected water into contact with a large surface area of (low permeability) matrix rock, in which the water can leak-off.

To verify that fractures have not propagated into the confining Halite layer, injectivity/step-rate tests (SRT) were carried-out in each water injection well in 2009, and during the first 3 years of injection (2011-2013). Such a test is carried-out with a memory pressure gauge installed in the tailpipe nipple of the completion close to the injection reservoir. Subsequently, injection is started and the injection rate (*Q*) is increased in steps. During each step the injection pressure is expected to stabilize. Plotting stabilized bottomhole pressure (*BHPi*) versus injection rate then gives information on the injectivity. In non-fractured reservoirs it is possible to detect formation breakdown from a change in the slope of the step-rate curve, as illustrated in Figure 4-7.

An overview of the SRT-plots for each well is given in Appendix A: no trend break in the slope of the step-rate curve is observed. Most SRT-plots show a linear trend, and the wells only require a low *BHPi* ($<\sigma_h$,min) to inject the planned water volumes. The curve intersects the y-axis at approximately the local near-wellbore pressure.

The inverse slope of the SRT is the injectivity index, which are listed in Table 4-3. The table indicates the duration per step, and whether the injection pressures (*BHPi*) had properly stabilized during the various steps. Operationally, this was not trivial because during the test only surface pressure reading were available (*THPi*) whilst these wells are sub-hydrostatic injectors; the *BHPi* can only be evaluated after the downhole memory gauges are retrieved. In case pressure stability is indicated as poor or very poor, the outcome of the SRT must be used with care.

Table 4-3 shows that for the subsequent step-rate-tests, the required stabilization time becomes longer. Before start of water injection it appears that the injection pressures stabilized within hours, whereas after 3 years of injection the rate steps need to last for weeks to ensure stabilization. This is attributed to the increasing volume, and hence radius, of water build-up around the well and associated gas/water mobility. In practice, because of required available injection capacity, scheduling SRT's becomes increasingly difficult with a risk of poorer data quality.

From 2014 onwards the injectivity tests were suspended. At the request of SodM, in 2015, NAM made an update of the Water Injection Management Plan. The final update was submitted in Nov-2018, Reference [2]. In this update the injectivity- and fall-off tests have been conditionally suspended. Instead, injectivity is surveyed more by daily monitoring of the surface injection pressure (*THPi*) at actual injection rate in combination with static reservoir pressure. In case unexpected changes in the injectivity are noticed that cannot be explained, an investigation will be carried out for which an ad-hoc injectivity test could be necessary. SodM has agreed with this proposal, but mentions that based on advice of external experts, the decision might be revisited if required, Reference [9].

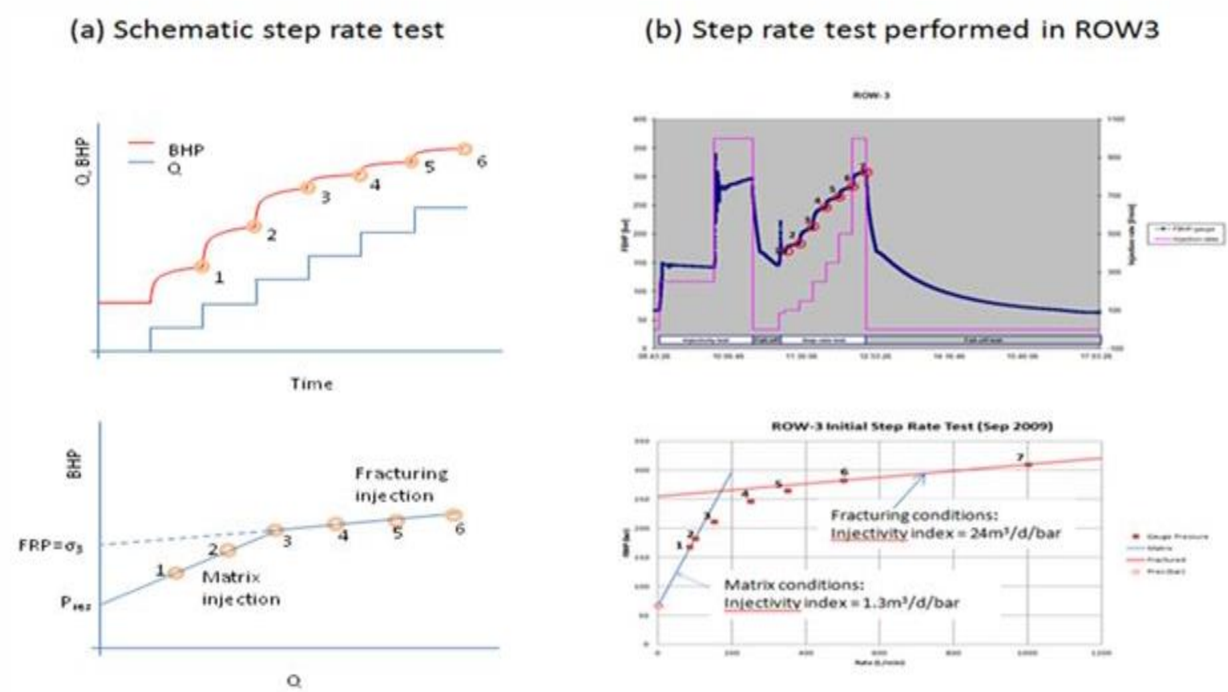

Figure 4-7: Illustration of a step-rate test in a matrix type reservoir. Data from well ROW-3 which connects to the Carboniferous (DC) sandstone reservoir.

Table 4-3: Overview of step-rate tests by well

Year	Well / Parameter	ROW-7	ROW-9	TUB-7	TUB-10
2009	**Injectivity, m3/d/bar**	-	-	-	-
	Pressure stability	-	-	-	-
	Duration per step	15 min	-	15 min	15 min
	Remark	Very good injectivity, no fluid at BHP gauge	No data	Very good injectivity, no fluid at BHP gauge	Very good injectivity, no fluid at BHP gauge
2011	**Injectivity, m3/d/bar**	-	12	-	77
	Pressure stability	-	Good	-	Fair
	Duration per step	-	1 day	-	1-2 days
	Remark	Unable to remove tree cap		Very good injectivity, no fluid at BHP gauge	
2012	**Injectivity, m3/d/bar**	55	9	-	130
	Pressure stability	Good	Good	-	Very good
	Duration per step	5 days	5 days	-	5-7 days
	Remark			No data due to faulty gauge	
2013	**Injectivity, m3/d/bar**	192	12	-	105
	Pressure stability	Very good	Good	-	Very good
	Duration per step	14 days	7-10 days	2.5-5 h	10-12 days
	Remark	Acid stimulated in June	Acid stimulated in June	Very good injectivity, no fluid at BHP gauge	

4.4.2 Pressure fall-off tests

Multiple pressure fall-off surveys have been conducted, mostly in conjunction and after the injectivity tests. The objective of these pressure fall-off tests was to determine the fracture closure pressure or minimum horizontal stress (σ_h,min). However, as explained in Chapter 4.4.1, water injection occurs in the existing network of natural fractures in the Zechstein Carbonates at a lower pressure than the σ_h,min. Consequently, it is not possible to determine the minimum horizontal stresses from the pressure fall-off curves. Furthermore, the fall-offs were highly affected by large wellbore storage effects resulting from falling liquid levels and fluid redistribution effects. As a result, the pressure response did not clearly show the characteristics of a dual porosity system. The interpretation suggest that ROW-9 has a relatively lower fracture density, which is in concurrence with the low productivity during the gas production phase (Q50 was 150,000 m^3/d).

Table 4-4: Fall-off test results

Well	Fracture spacing (m)	Permeability (mD)	Skin	Data quality
ROW-7	0.2	900	3.7	Poor
ROW-9	5	17	-2.5	Good

5 Management of Halite dissolution risk

5.1 Introduction

The initial Schoonebeek production water was saline (under-saturated) formation water. As time progresses, the injected steam (condensed water) breaks through from the Schoonebeek steam injection wells to the Schoonebeek production wells, reducing the produced water salinity. This means that the injection water will have a significant capacity to dissolve salt.

Figure 5-1 shows a typical water injector well schematic where the production packer is set above Halite layers present in the Zechstein formation. To assess the Halite dissolution risk, modelling was performed by Shell P&T in Rijswijk, Reference [10]. The results of the modelling indicate that significant Halite dissolution can only take place near the injection well in case two specific conditions are simultaneously met. Only in case the production casing is leaking and its cement bond has also degraded, there is a path for water to flow directly past the Halite formation potentially leading to Halite dissolution, Reference [11]. If only one of these two conditions is met, the injection water can come into contact with the Halite, but due to lack of flow it cannot dissolve significant amounts of Halite. The confining Halites under and above the target reservoirs in ROW are shielded by the containing Anhydite layers, which implies that further away from the well, injected water cannot contact the Halite.

In order to mitigate the risk of Halite dissolution, a monitoring scheme was therefore applied to verify the status of the production casing and cement at the level of these Halite sections, consisting of temperature logging, casing caliper surveys and cement bond logging (CBLs). The monitoring results for each survey are discussed in the next sections.

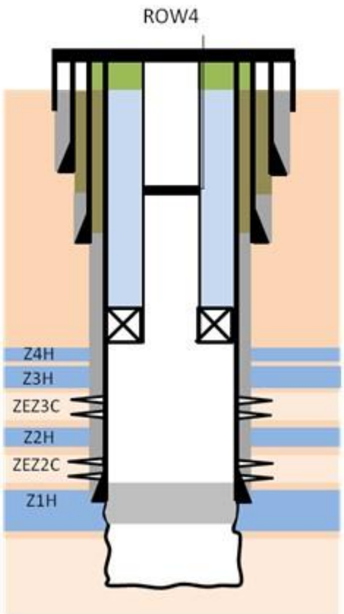

Figure 5-1: Typical water injector well schematic showing Halite sections behind production casing (ZnH represents salt layers, ZEZnC represents carbonate layers where the water is injected into. Between the salt and carbonate layers is a thin Anhydrite layer)

5.2 Temperature logging

Temperature logging has been performed to check whether injection occurs into the injection reservoirs only or also into Halite sections. To this end a temperature log was run several days after injection had been stopped. Based on the fact that the injection water is much cooler than the injection reservoirs and surrounding reservoir seals, the layers that received most injection are expected to warm back much slower than layers where no injection occurred.

The temperature survey results have been summarized in Table 5-1. Injected volume during a representative period and shut-in time prior to logging are specified. Observations and comments on the temperature logging result are listed in the table for each well. The temperature surveys are included in Appendix B. In the pictures in Appendix B, the red curve represents the undisturbed geothermal gradient that is generally applied for the underground in The Netherlands:

undisturbed temperature = 10.1°C + 0.031°C/mTV

In well ROW-7 the actual injection points within the Zechstein Carbonate layers can be differentiated, which appears to line up very well with the PLT that was run during the gas production phase. Unfortunately, in TUB-7 the gauges didn't record during the temperature survey. The temperature log shown in Appendix B.3 is recorded at a different moment. Still, this temperature log also confirms that injection takes place in the ZEZ3C (delayed heat-up relative to the over-/under-burden). The survey did not cover the ZEZ2C.

Unambiguous verification of injection into the Carbonate formations only is masked by the varying conditions at which the temperature surveys are executed (i.e. volume injected and shut-in period prior to logging). ROW-9 (Appendix B.2) was only shut-in for 6 hours, which is relatively short to measure a clear warm back from the ZEZ3H overburden. From the temperature surveys in ROW-7 (Appendix B.1) and TUB-10 (Appendix B.4) it is relatively difficult to differentiate injection into Carbonate layers versus that into the Z2H, which is located in between the Z2C and Z3C injection reservoirs. Temperature logs can always show some "smearing" effect. Because of the injection of significant volumes of cold water preceding the temperature survey it is very likely that the ZEZ2H in between the two injection reservoirs as well as the ZEZ3H directly overlying the ZEZ3C reservoir have cooled down as well (conductive cooling), which causes the warm back during the shut-in period to occur much slower. Zooming in on these temperature surveys, shown for TUB-10, however, does show that the warm back of the ZEZ2H has started.

Warm back between the Carbonate reservoirs and the ZEZ2H layer is very clear in well ROW-4, with a long enough shut-in time relative to the small volume of water injected.

For future temperature surveys it is recommended to apply a longer shut-in period prior to a temperature survey to allow the ZEZ2H to sufficiently warm back. However, operationally this is difficult to realize. With only 4 wells available (ROW-2, ROW-4, ROW-5 and ROW-7), this implies that required long shut-in times are not practical in relation to the large volume of water that will be injected in these wells.

Table 5-1: Temperature survey results

Well	Date of survey	Injection volume (injection period)	Shut-in period	Injection into injection reservoir	Clear injection points identified within ZeZC	Comments
	dd-mon-yy	m3	days	yes/no/unclear	yes/no/unclear	
ROW-4	12-Dec-12	1,200 (20d)	0.9	yes	yes	Injection point aligns with gas production PLT run in June 1991
ROW-7	22-Jan-13	28,000 (31d)	1.1	yes	yes	Injection into ZeZ2C and ZeZ3C can be differentiated vs over-/underburden. However, differentiation between ZeZ2C and ZeZ3C vs interlying Z2H is difficult due to large injection volume preceding T survey. This also complicates identifiying individual injection points within ZeZC reservoirs.
ROW-9	11-Jan-13	11,000 (17d)	0.3	yes/unclear (see comment)	unclear	
TUB-7	28-Feb-13					Gauges did not record during T survey
TUB-10	04-Mar-13	45,000 (32d)	1	yes/unclear (see comment)	yes/unclear (see comment)	Injection into ZeZ2C and ZeZ3C can be differentiated vs over-/underburden. However, differentiation between ZeZ2C and ZeZ3C vs interlying Z2H is difficult due to large injection volume preceding T survey. Sharp T drop observed when entering ZeZ3C. This injection point aligns with gas production PLT of Feb 1999.

5.3 Cement bond logging and casing condition surveys

The temperature logs clearly show that water is injected into the perforated Carbonate formations, and there is no evidence that injected water has come into contact with Halite layers. However, in some cases contact to Halite cannot be entirely excluded from the observed warm-back of the Halite and Anhydrite layers in between the ZEZ2C and ZEZ3C and above the ZEZ3C. Large injected volumes have cooled down the reservoir so much that warm-back effects are masked. A relatively small volume leaking-off to the Halite via a potential casing leak may not be large enough to cause sufficient cooling to be detected by temperature logging.

For that reason, in addition to temperature surveys, also cement bond logs (CBLs) and production casing calipers were run to verify whether any injection water contacts Halite formations. Caliper surveys of the casing section below the production packer and tubing tailpipe were explicitly executed to establish the casing integrity/wall thickness in order to timely detect weak spots and avoid that salt layers might be directly exposed to the injected water. The objective is, therefore, fundamentally different from the tubing caliper surveys that were carried-out to verify the injection tubing integrity status (section 6.1). Weak spots in the tubing, most often due to corrosion and/or erosion causing reduction of the wall thickness, can lead to tubing-annulus communication and, hence, loss of the primary well barrier. It is important to note that caliper tools are multi-finger imaging tools measuring inside, and not behind, the tubing/casing.

Only in case the casing caliper detects a leak in combination with poor cement bond across a Halite formation, there would be a path for water to flow directly past the Halite formation, potentially leading to Halite dissolution.

CBLs were carried out in 2013 in wells ROW-9, TUB-7 and TUB-9. The logs are presented in Appendix C. Note that a CBL in ROW-7 could not be recorded. ROW-7 contains a 9 ⅝" production casing and 3½" tubing (with 2 ¾" nipple). This large difference in Internal Diameter (ID) of the tubulars makes it impossible to run a meaningful CBL. However, during the drilling of the well a CBL was run immediately after cementing the production casing. This CBL shows that the cement bond behind the production casing is of excellent quality.

To assess the casing condition, multi-finger caliper surveys of the casing section below the packer have been run in TUB-7 and TUB-10 in 2013, and in ROW-9 in 2013 and 2015. As these wells are no longer in use for water disposal since 2015 and are currently suspended, these are the latest surveys done in these 3 wells.

In ROW-7 the casing condition has been assessed by recording an EMIT survey in 2015, and a Multi-Tube Integrity survey in 2020. Multi-finger tools cannot provide meaningful data in ROW-7 due to the large ID difference between casing and tubing as mentioned above.

Table 5-2 summarises the conclusions from the surveys. The table also presents the risk level of exposure of the Halite to injected water, which is assessed to be "low" in the wells under discussion.

Table 5-2: Overview of CBLs and calipers run in production casing underneath injection packer

Well	High level conclusions	c/c*		Way forward	Risk level
ROW-7	Legacy/historic CBL data indicate good cement bond over relevant intervals. 2020 MIT results indicate <5% metal loss in the casing section below the packer and above the perforations , including the section opposite the tubing tailpipe			Run EMIT, MIT or equivalent tool every five years.	Low
ROW-9	Good cement bond, no casing corrosion but minor corrosion in tubing.			Well is suspended, not in use as water injector.	Low
TUB-7	Good to fair cement bond over 3H and 2H, poor cement over 3C. 2013 Casing caliper re-evaluated in 2015, confirms casing integrity.			Well is suspended, not in use as water injector.	Low
TUB-10E	Good cement bond and minor to no casing corrosion over 3H, 3C, 2H and 2C and 1H.			Well is suspended, not in use as water injector.	Low

*Casing / cement over halite intervals: colour coding low-medium-high.

6 Well integrity surveillance and management

6.1 Hold-Up Depth Monitoring

Monitoring of the Hold-Up Depth (HUD) in the well is done to monitor the possible accumulation of solids at the bottom of the well. Changes in HUD over time could be an indication of issues with stability of the exposed reservoir formation or perforations, with quality control of the injection water, or even with deformation of tubing or casing. Figure 6-1 presents the recorded HUD measurements since the wells were completed on their present reservoir zone. Only minor variations in HUD are observed (in the order of +/- 2m), which are likely caused by inaccuracies in the slickline measurement method. There is no indication of a drastic change or consistent rise in HUD in any of the wells.

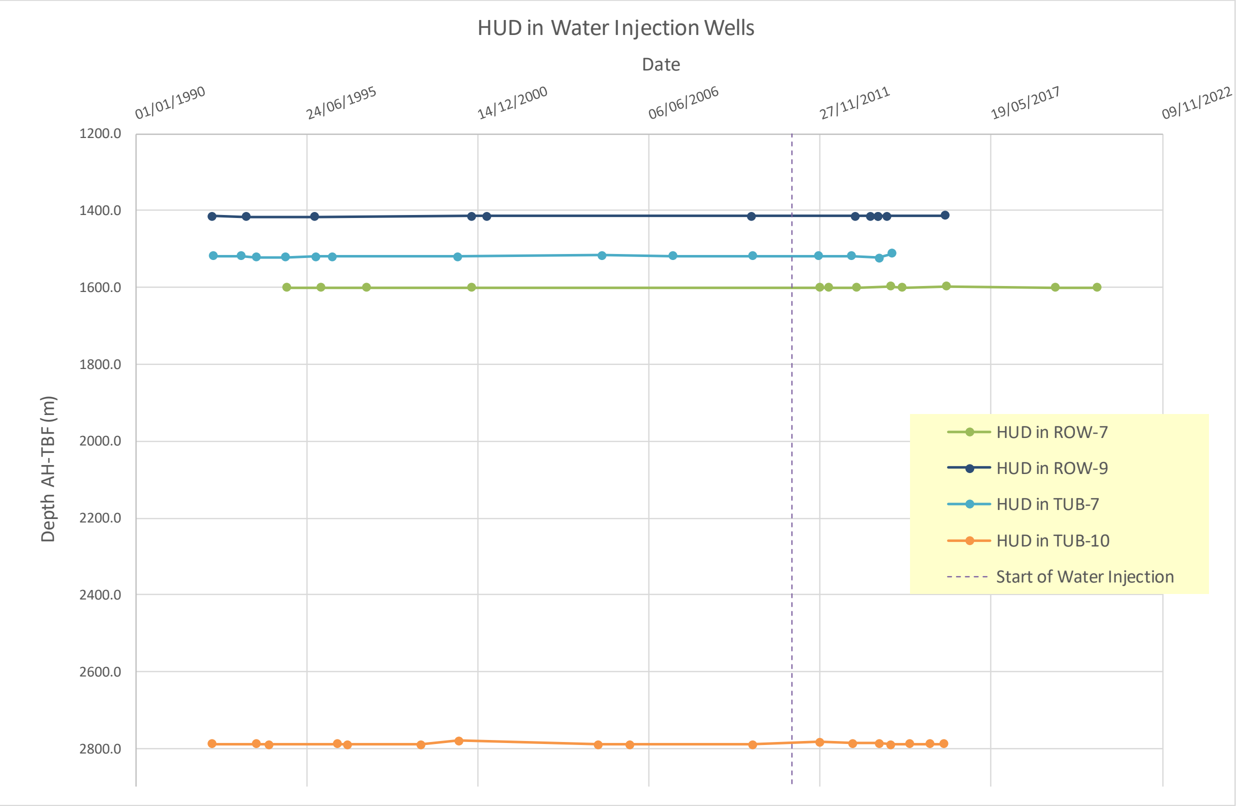

Figure 6-1: Measured well Hold-Up Depths in ROW-7, ROW-9, TUB-7 and TUB-10, before and after the start of water injection. Note that HUD measurements in ROW-9 and TUB-7/-10 were stopped when these wells were suspended in 2015.

6.2 Tubing caliper surveys

Weak spots in the tubing, most often due to corrosion and/or erosion causing reduction of the wall thickness, can lead to tubing to A-annulus communication and hence to loss of the primary well barrier. To verify the integrity state of the tubing, caliper surveys have been regularly carried-out in all water injectors. Similar to the casing calipers, a multi-finger tool is used to circumferentially measure the inner tubing radius. The surveyed data is then processed to provide a maximum wall penetration depth and maximum percentage metal loss for each tubing joint. Calipers do not measure wall thickness, i.e. the condition of the outside of the pipe is assumed to be at nominal condition. Note, however, that the outside surface of the injection tubing is not in direct contact with potentially corrosive fluids.

The maximum wall penetration depth measured in each well since start of injection is presented as degree of pitting in Figure 6-2. The red dashed line indicates the pitting degree limit of 60%, at which NAM's practice is to consider change-out of the tubing, References [12] and [13]. WellCat modelling shows that with 60% corrosion (i.e. assuming worst case scenario that 60% pitting exists uniformly along the entire tubing) the axial and tri-axial loads are approaching the design factors. Figure 6-2 shows that the measured degree of pitting, based on the maximum recorded pitting depth (considered the weakest point in the tubing) for all wells is still below the pitting degree limit of 60%, except for ROW-7. The 2016 survey indicated pitting just above 60%. However, repeat surveys in 2017 and 2018 showed significantly lower maximum wall thickness loss, indicating that the observed pit in 2016 is relatively small in size (given that the 24 arms of the caliper tool did not detect the same pit both in 2017 and

2018). The 2020 survey again indicated the pitting at the same depth to be about 60%. The overall integrity of the ROW-7 tubing condition is still classified as moderate, but the tubing section with the deepest pitting will be considered for pro-active repair.

Table 6-1 summarizes the actual integrity state of the tubing for each well with respect to the observations from the various caliper surveys. Wells that are no longer used for water disposal are not part of the surveillance scope.

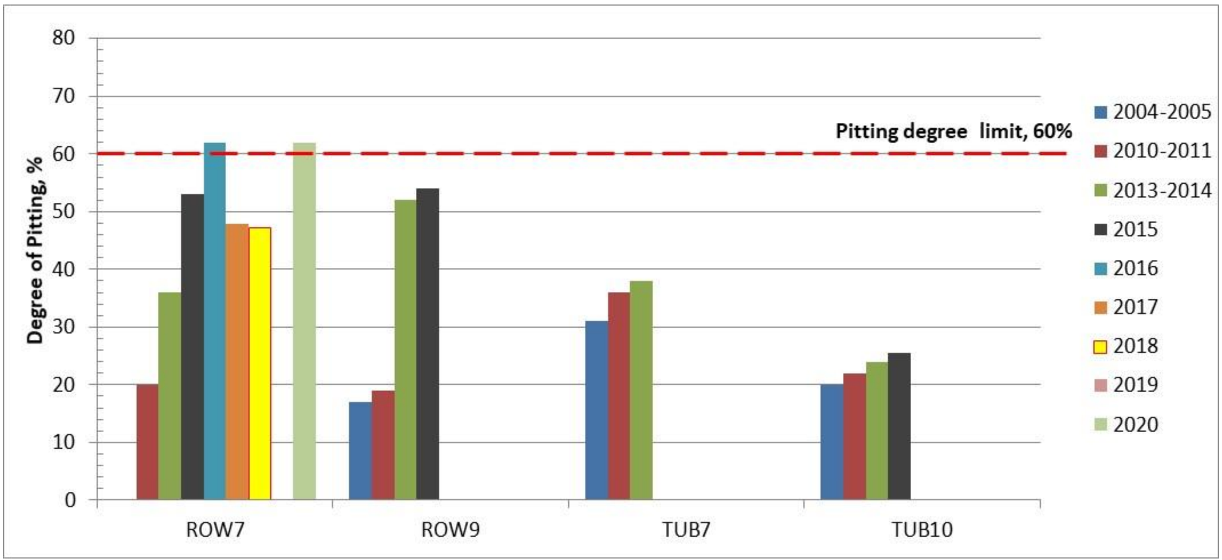

Figure 6-2: Maximum wall penetration for each injection well derived from caliper surveys since start of injection
Notes: (1) ROW-9, TUB-7 and TUB-10 have been suspended since 2015 therefore no recent tubing caliper surveys; (2) Tubing caliper in ROW-7 could not be executed in 2019 due to operational issues.

Table 6-1:Overview of tubing conditions from caliper survey data

parameter	surveillance tool	ROW-7	ROW-9	TUB-7	TUB-10
Casing size, in. Production Casing install date Start date of water injection years gas producer Tubing depth incl. top PP (m AHTBF) Tubing size (inch)		9.625 Jan-1977 Nov-2009 32 1214.41 3.5	7.625 Apr-1978 Sep-2009 31 1304.86 3.5	4.5/OH Dec-1953 Dec-2009 56 1170.50 3.5	7.625 May-1974 Dec-2009 35 1600.40 3.5
Max.penetration depth, % Tubing/Casing Date	PMIT 2004-2005		17% t Oct-2005	31% t Nov-2005	20% t Oct-2005
Max.penetration depth, % Tubing/Casing Date	Kinley 2010-2011	20% t Nov-2010	19% t Mar-2011	36% t Oct-2010	22% t Oct-2010
Max.penetration depth, % Tubing/Casing Date Interval	PMIT 2013-2014	36% t/c Jul-2014 1126 m	52% t/c Oct-2013	38% t/c Oct-2013	24% t/c Oct-2013
Max.penetration depth, % Tubing/Casing Date Interval	PMIT 2015	53% t/c Dec-2015 1165-1174m	54% t/c Dec-2015	no injection	26% t Nov-2015
Max.penetration depth, % Tubing/Casing Date Interval	PMIT 2016	62% t Nov-2016 1162.21 m	no injection	no injection	no injection
Max.penetration depth, % Tubing/Casing Date Interval	MFCT 2017 24-Arm MIT Expro	48% 3-1/2" Nov-2017 1162.2m	no injection	no injection	no injection
Max.penetration depth, % Tubing/Casing Date Interval	MFCT 2018 24-Arm MIT Expro	47% 3-1/2" Oct-2018 1162.16m	no injection	no injection	no injection
Max.penetration depth, % Tubing/Casing Date Interval	MFCT 2019 24-Arm MIT Expro		no injection	no injection	no injection
Max.penetration depth, % Tubing/Casing Date Interval	MFCT 2020 24-Arm MIT Expro	62% 3-1/2" Oct-2020 1162.2 m	no injection	no injection	no injection
Tubing condition		Good to fair, with 2 isolated pits showing moderate condition	no injection	no injection	no injection

6.3 Annulus pressure monitoring

In addition to tubing caliper surveys, which are only carried-out once per year to identify weak spots in the tubing wall in time, continuous annulus pressure monitoring (in particular for the A-annulus) is also in place to detect whether the tubing and/or casing integrity is breached. In case sudden or unexpected changes in the annulus pressure are observed, which could indicate a leak path between the tubing and the A-annulus or between the A-annulus and the B-annulus, an investigation will be started.

In all water injection wells in Twente, the A-annulus is filled with KCl-brine (1.03 sg with pH value of 11), which was circulated into the A-annulus when the wells were converted into water injectors. The B- and C-annuli contain water-based fluids of varying densities ranging from 1.25 to 1.4 sg. In the A- and B-annulus a minimum pressure is maintained by topping up the annuli with N2 gas.

For all water injection wells in Twente, integrity tests (WITs[9] and SITs[10]) are carried out each year. The tests show that there is no pressure communication between the tubing and the A-annulus, nor between the A- and B-annulus. This is also in accordance with the observation that the pressures at the tubing head, the A-annulus and the B-annulus are different and do not follow the same trend. This implies that all barriers between the tubing and the A-annulus, as well as between the A-annulus and the B-annulus are intact for all injection wells.
In addition, from the WITs and SITs observations, no leaks to the environment from the casing system have been observed.

Since the start of water injection the A-, B- and C-annulus pressures have not exceeded the Maximum Allowable Annulus Surface Pressure (MAASP). For the A- and B-annuli also a MinAP (Minumum Annulus Pressure) was defined, to avoid oxygen ingress upon cooling of the wellhead, but also as a diagnostic tool in case of sudden or repeated loss of annulus pressure.

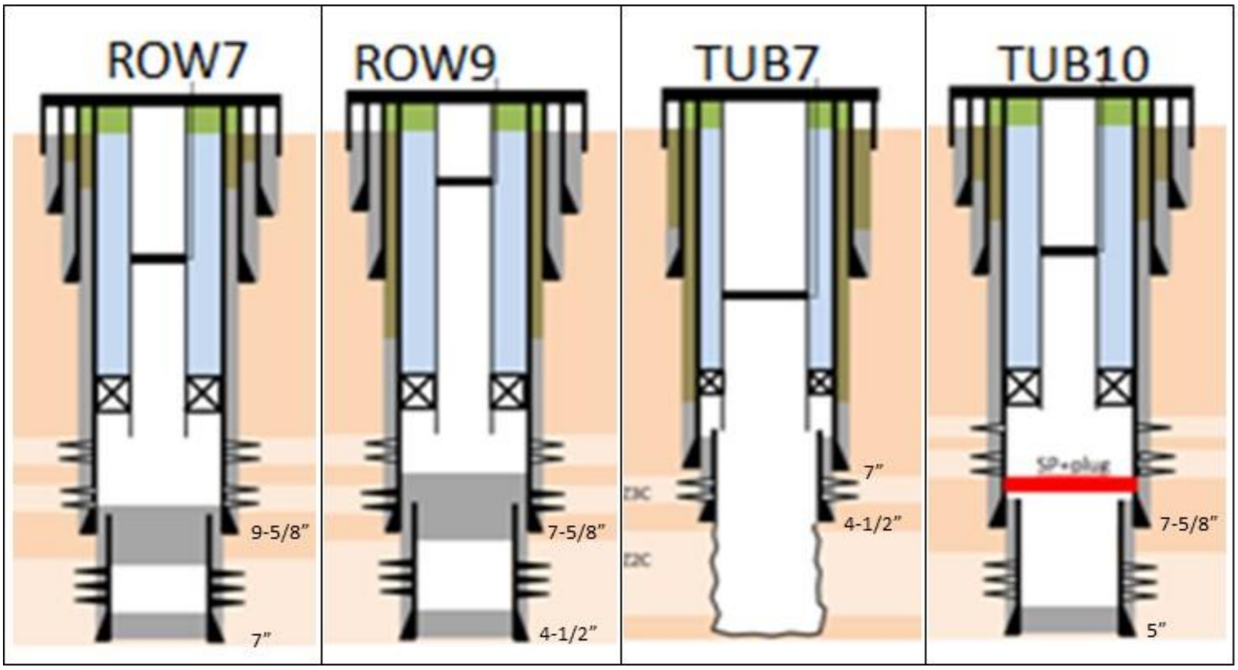

Figure 6-3: Well schematics for the water injection wells

6.4 TUB-7

Based on a casing caliper survey carried out in Q4-2013, the Technical Evaluation of 2014 (Ref. [1]) mentions possible casing damage in the 7" and 4-1/2" casing strings. Additional surveys (CBL, Temperature and PLT) did not provide any indication for loss of integrity of the casing/liner system. For a detailed discussion of the survey results, please refer to Section 9.7 in Ref. [1]. Appendices B.3 and C.2 of this report present the results of the surveys in TUB-7 done in 2014.

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9 WIT (wellhead integrity test) is the routine scheduled preventive maintenance task for flow-wetted components of the well, which implies that the integrity of the sub-surface safety valve and Xmas-tree valves is tested.

10 SIT (subsurface integrity test) is the routine scheduled preventive maintenance task for non-flow-wetted components of the well, i.e. seals between the tubing and annuli are pressure tested.

At the time, the nature of the feature in the 4-1/2” liner located at 1464 mAH-DFE (opposite the ZEZ2 Halite layer) remained an uncertainty, with an unscrewed or under-torqued casing connection mentioned as possible explanations. TUB-7 was kept shut in awaiting further investigation. In fact, the well has not been used for injection since Aug-2014.

Upon close review of the 4-1/2” liner tally, it became clear that at a top depth of 1462 mAH-DFE, a baffle collar has been installed in the liner string, which has a function similar to a (nowadays more usual) casing float collar in catching the cement plugs. The baffle collar was drilled out after the cementation of the 4-1/2” liner to gain access to the open hole section below the liner during well construction in 1953. However it still showed up as an area with a profile different from the main casing ID in the caliper survey of Oct-2013, giving rise to a misinterpretation as an unscrewed or under-torqued casing connection. In terms of integrity, the baffle collar acts as a regular casing collar so does not pose an issue. This is confirmed by the Temperature and PLT survey results that do not indicate water loss at the depth of the baffle collar.

7 Conclusions

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM-1, TUM-2, ROW-2, ROW-3, ROW-5, ROW-6 and TUB-7) to dispose Schoonebeek production water in depleted gas reservoirs in Twente, NAM is requested to evaluate and report the water injection process and activities every 6 years.

This evaluation report comprises the second periodic evaluation for wells ROW-7, ROW-9, TUB-7 and TUB-10. The first periodic evaluation was done in 2014 (3 years after start injection) because these wells were expected to show faster pressure increase with respect to connected reservoir volume and planned injection rate.

From an environmental point of view, the key concern is the mitigation of the risk for contamination of shallow aquifers due to loss of containment. The technical evaluation focused therefore in particular on the effect that water injection has on the integrity of the wells and sealing (confining) cap rock above the target injection reservoir.

The conclusions from the technical evaluation carried out are:

- Well TUB-7 has been shut in since mid-2014, wells TUB-10 and ROW-9 have been shut in since mid-2015, i.e. just before and some 6 months after the previous technical evaluation of end 2014.
- The well monitoring program (as defined in the WIMP, Reference [2]) provides an appropriate early detection and protection framework to guarantee the integrity of both the wells and reservoirs and thus a safe and responsible operation.
- The tubing in ROW-7 is in moderate condition and can be used for future water disposal. The tubing section most affected by pitting will be considered for pro-active repair.

Regarding the water injection volumes, the following is concluded:

- The actual total injection rate has been significantly lower than the predicted, due to lower performance of Schoonebeek Oilfield production wells and restrictions in the water export pipeline.
- Thus far, only 22% of the modeled injected volume has actually been injected into the Rossum-Weerselo Zechstein reservoir (including wells ROW-7 and ROW-9), and only 18% was injected into the Tubbergen Zechstein reservoir (wells TUB-7 and TUB-10) before cessation of injection.

From static pressure gradients (SPG's), the actual surface injection pressures (*THPi*) and the injectivity and steprate/fall-off tests the following is concluded, respectively:

- The actual pressure in the various reservoirs is still significantly lower than the original reservoir pressure.
- The measured local pressure increased slightly faster than expected in wells TUB-10 and ROW-9.
- All wells inject under sub-hydrostatic conditions, the required downhole pressures to drive the water rates into the reservoir are too low to sustain a full water column to the tubing head. The water effectively free-falls from the tubing head into the well, and the tubing head pressure do not reflect information about downhole reservoir behavior.
- The amounts of water injected thus far is still too small to make an accurate prediction of the final storage capacity based on the pressure trends. Multiple dynamic effects are simultaneously at play during the water injection, at a similar order of magnitude as the reservoir pressure increase at the cumulative water injected.
- During the entire injection period, the surface injection pressure remained well below the set THPi-limits for the wells. Hence, for all wells the maximum bottom hole pressure ($BHPi_{max}$) has never exceeded the minimum in-situ stress (σ_h,min) of the confining layer (ZEZ-Halite).
- The SRT-plots derived from the injectivity tests all show a linear trend indicating injection into existing fractures in the naturally fractured Zechstein-Carbonate reservoir, which means that injection occurs below fracturing pressure.
- The quality of step-rate test results is relatively poor, as it takes longer to achieve downhole pressure stabilization every subsequent year.
- It was not possible to determine the minimum in-situ stress in the Zechstein-Carbonate reservoir from pressure fall-off curves, because injection does not occur above fracturing conditions.
- Since injection does not take place under fracturing conditions, determination of minimum horizontal stress from fall-off surveys cannot be done as intended, and fall-off tests for that purpose have been postponed. Pressure transient analysis suffers from large wellbore storage effects, and only indicative results for permeability can be obtained. Tracking well injectivity through step-rate test analysis is considered a more useful and straightforward approach. However, the long time required for pressures to

stabilize for each injection step leads to inaccurate results and makes step-rate testing more and more impractical in the future.

- Injectivity in wells ROW-7, TUB-7 and TUB-10 is considered very high, whereas in well ROW-9 it appears to be moderate.
- Fall-off test analysis suggested a relatively lower fracture density around ROW-9.

Extensive studies have been carried-out regarding Halite dissolution when exposed to injection water and its potential effect on subsidence. These studies have been independently reviewed by University experts under auspices of State Supervision of Mines[11]. From Halite dissolution modelling it was concluded that potentially this can only occur near the injection well. Hereto, a leak in the production casing in combination with a poor cement bond behind casing must occur simultaneously in order to allow injection water to directly flow past the Halite formation. Temperature surveys, cement bond logging and casing caliper surveys were executed to detect if Halite is exposed to injection water. From the logging the following is concluded:

- Downhole temperature surveys indicate that injection occurs into the targeted Zechstein-Carbonate reservoirs and not in the Halite formations.
- Temperature surveys do not show anomalies that could be indicative for significant leakage to the Halite (a relatively small volume may not cause sufficient cooling to be detected by temperature logging).
- For all wells it is clear that warm-back is slower in the target injection reservoir compared to that of the overlying/underlying layers.
- Warm back is masked in case very large volumes of water were injected and the shut-in period prior to logging was too short. Also the layers above the injection reservoir were significantly cooled-off in those wells.
- The risk to dissolve Halite is perceived negligible in all logged wells based on the condition of casing/liner from positive interpretation of caliper surveys and cement bond logs.

Evaluation of the well and tubing integrity show that:

- Tubing strength calculations show that all the tubings still have enough wall thickness (degree of pitting $\leq$ 60%) to withstand maximum injection pressures. No tubing leaks have been detected.
- During the current evaluation period all A-, B- and C-annulus pressures have remained below their Maximum Allowable limit (MAASP).
- Pressure data demonstrate full pressure isolation between the tubing, A-annulus and B-annulus.

[11] These studies have been independently reviewed by independent University experts under auspices of the Dutch Mining Regulator (State Supervision of Mines). All the conclusions and findings of the studies were supported by both the experts and the regulator. (https://www.sodm.nl/actueel/nieuws/2016/06/23/reviews-rapporten-waterinjectie-twente)

8 References

[1] Technical evaluation of Twente water injection wells ROW3, ROW4, ROW7, ROW9, TUB7 and TUB10 3 years after start of injection. EP201410210164, January 2015.

[2] Water Injection Management Plan. EP201810244166., October 2018.

[3] Technical evaluation of Twente water injection wells TUM1, TUM2, TUM3, ROW2, ROW3, ROW4 and ROW5 6 years after start of injection. EP201701214429, January 2017.

[4] Jaarrapportage 2019 Waterinjectie Schoonebeek/Dalen, 15 April 2020.

[5] Schoonebeek Oilfield Redevelopment - VAR 3 Field Development Plan. Final Version, October 2003.

[6] P. Weijermans and G. Warren, Dynamic Modelling of Produced Water Reinjection in Depleted Naturally Fractured Gas Fields, June 2006.

[7] T. Vandeweyer, Technische beschrijving Water Injectie Schoonebeek Project, Juli 2009.

[8] P. Weijermans, Schoonebeek Produced Water Disposal Study, Dynamic Modelling of Water Injection in Depleted Naturally Fractured Zechstein Carbonates, June 2004.

[9] Staatstoezicht op de Mijnen, Uw addendum op het evaluatierapport Twente waterinjectie, kenmerk 15137190.

[10] C. Pentland, Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal, September 2013.

[11] Overkoepelende analyse ondergrondse risico's waterinjectie Twente, November 2016.

[12] W. Kolthof and D. Van der Wal , The use of digitised tubing caliper data for workover planning., September 1991.

[13] A. Ciufu, Twente water disposal wells - tubing integrity review, March 2016.

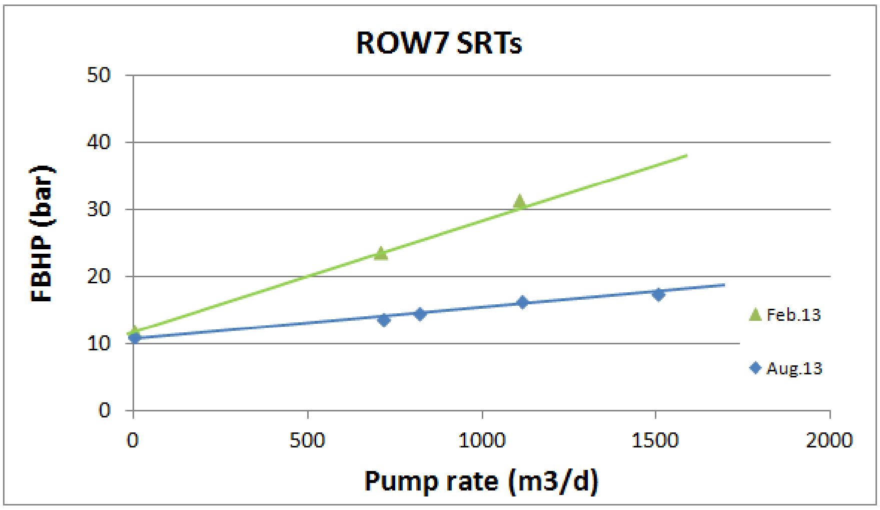
[14] Concept Addendum Waterinjectie Management Plan - Voorstel om het surveillance programma voor waterinjectie en de tabel voor jaarlijkse rapportage aan te passen, April 2015.

[15] Addendum to 3-yearly technical evaluation report, August 2015.

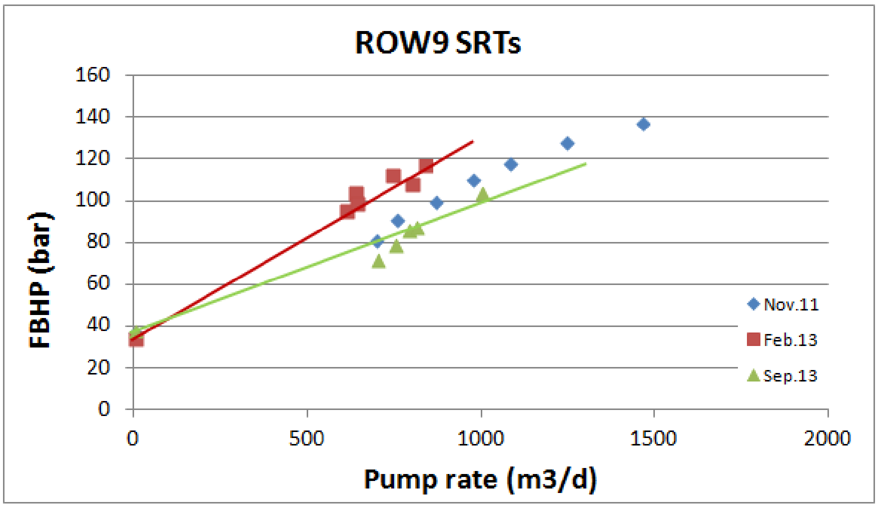
Appendix A Step-rate test results

Note: all measured flowing bottomhole pressures (FBHP) at gauge depth have been recalculated to top reservoir.

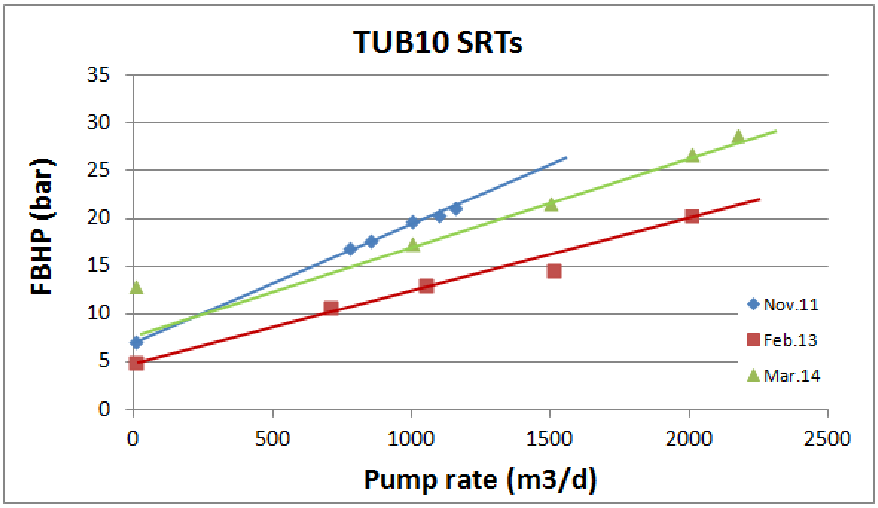
A.1 ROW-7



A.2 ROW-9



A.3 TUB-10


TUB10 SRTs
FBHP (bar)
35
30
25
20
15
10
5
0
0
500
1000
1500
2000
2500
Pump rate (m3/d)
Nov.11
Feb.13
Mar.14

Appendix B Temperature logging results

B.1 ROW-7

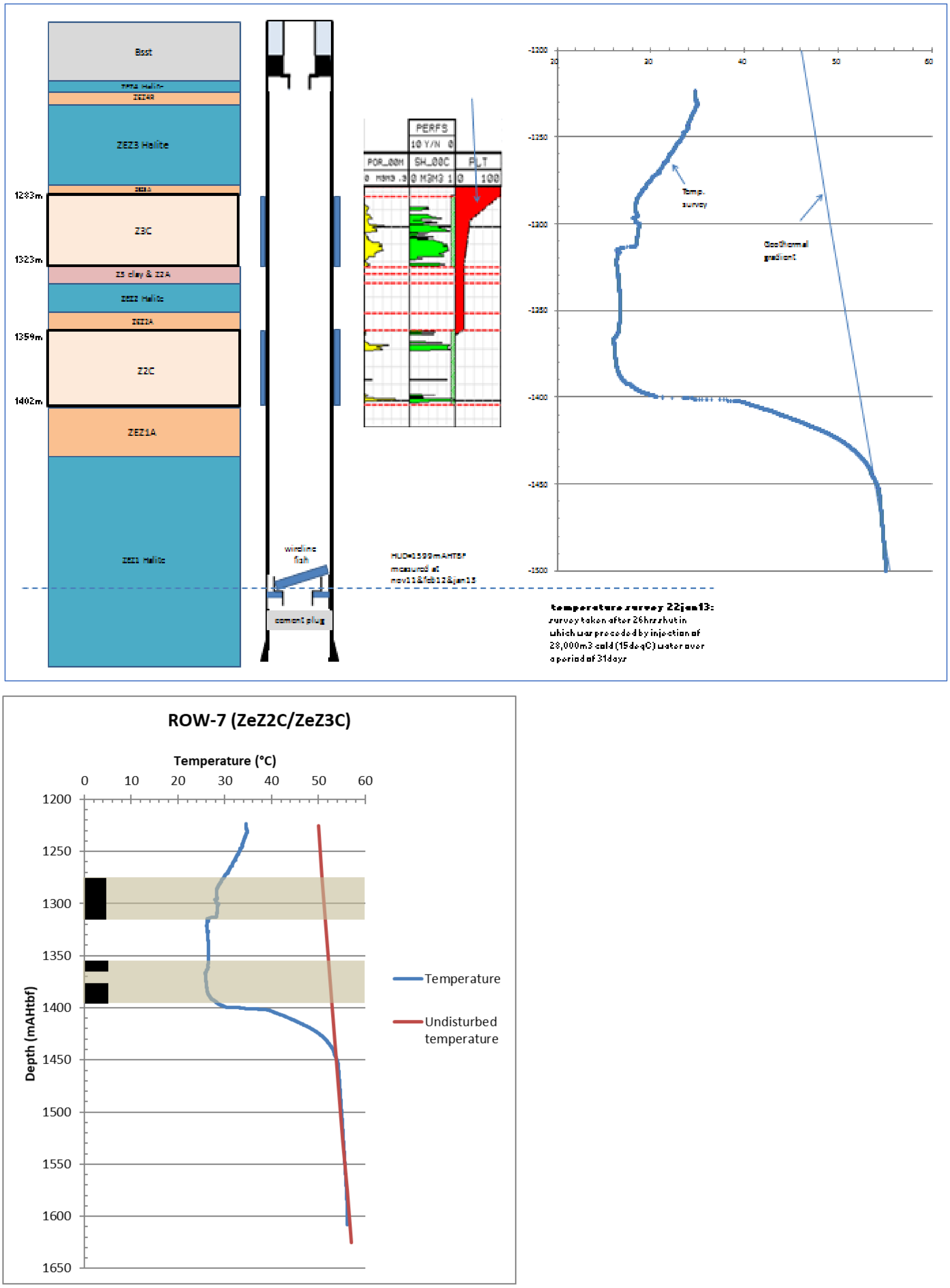


Figure B-1: ROW-7 temperature survey, January 2013

B.2 ROW-9

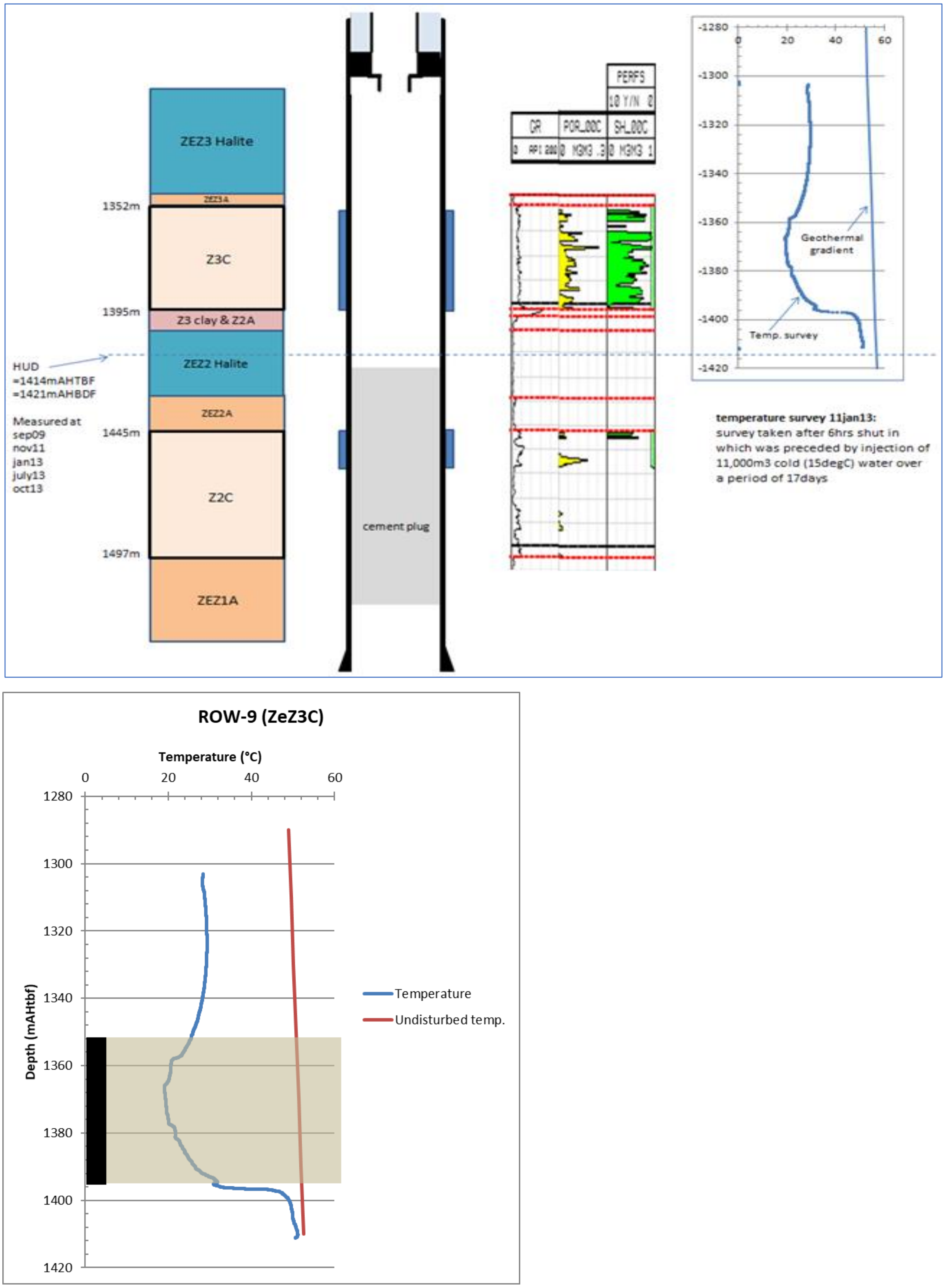


Figure B-2: ROW-9 temperature survey, December 2012

B.3 TUB-7

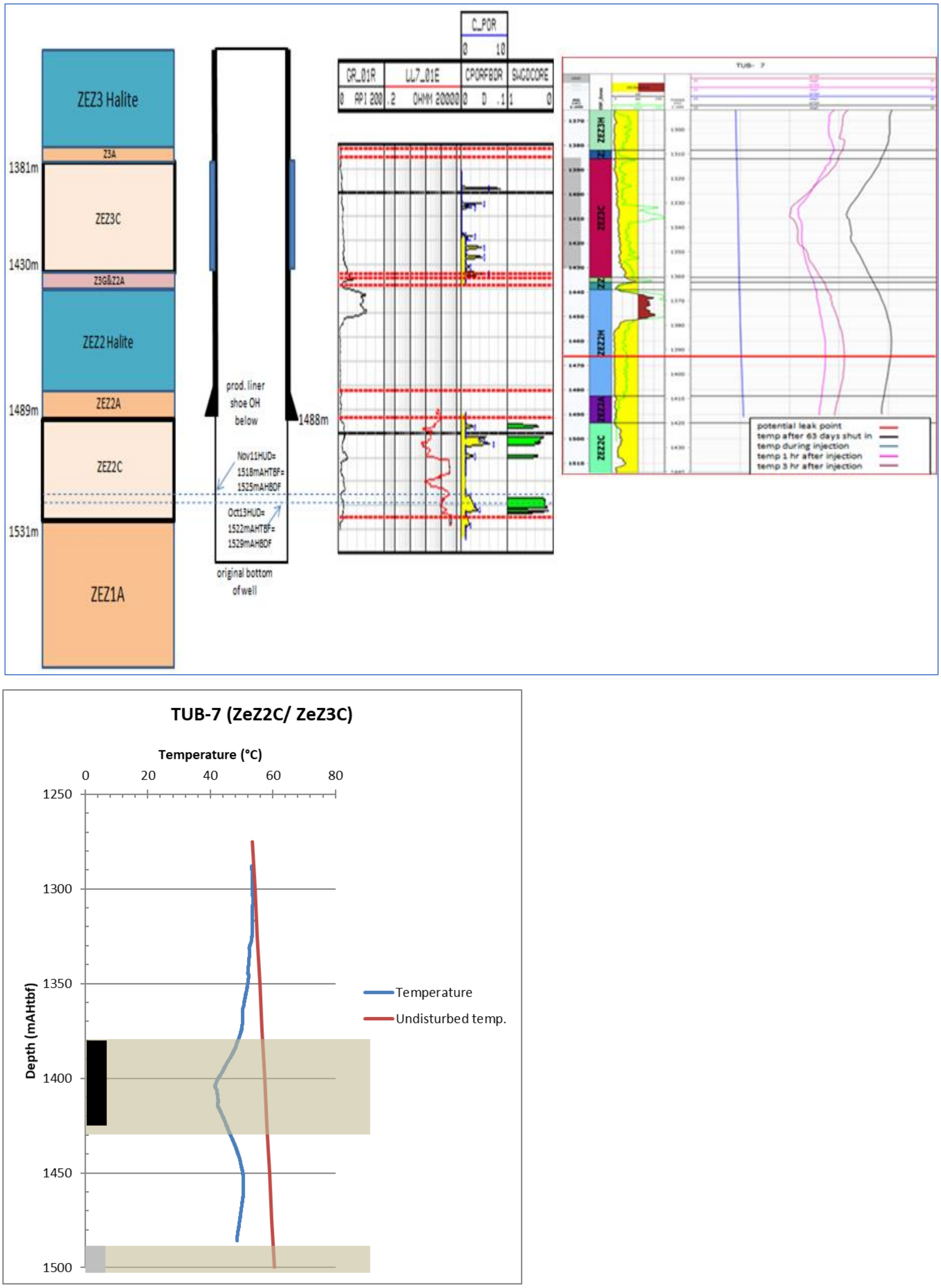


Figure B-3: TUB-7 temperature survey, March 2013. Please note that the "potential leak point" at 1464 mAH-DFE was later identified to be a baffle collar located in the 4-1/2" liner, which is not an issue wrt casing integrity. The temperature survey does not indicate water loss from the casing at that depth.

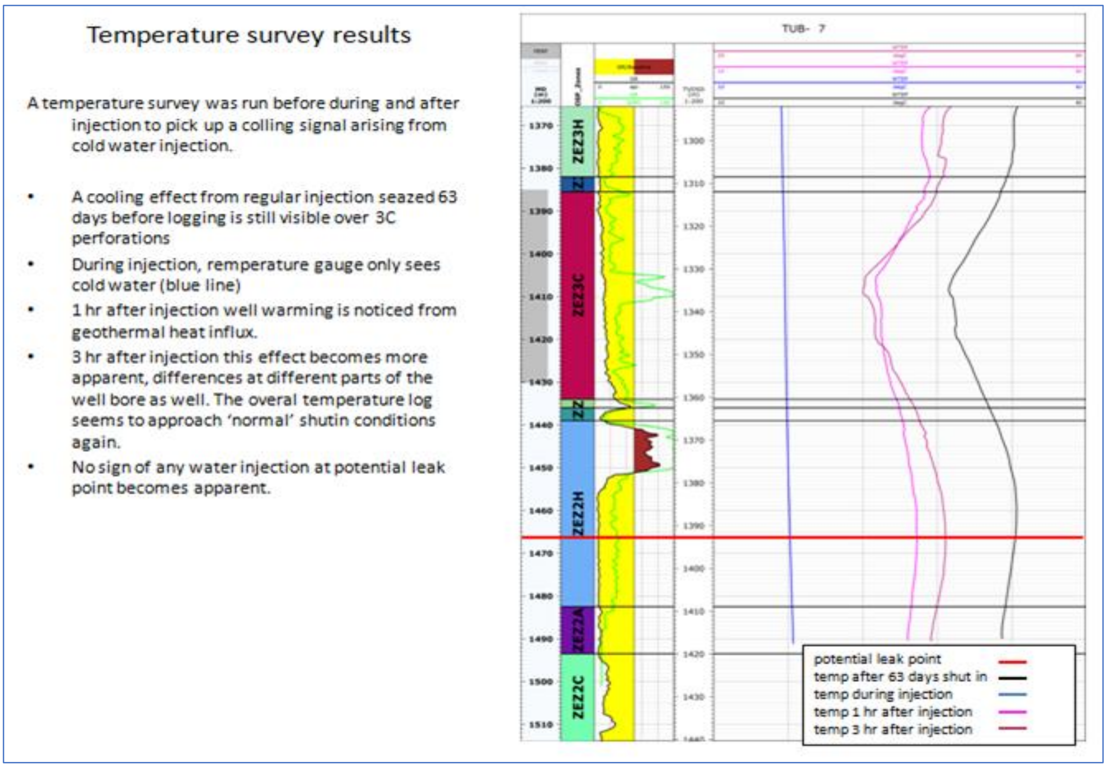


Figure B-4 –TUB-7 temperature logging results. Please note that the "potential leak point" at 1464 mAH-DFE was later found to be a baffle collar located in the 4-1/2" liner, which is not an issue wrt casing integrity. The temperature survey does not indicate water loss from the casing at that depth.

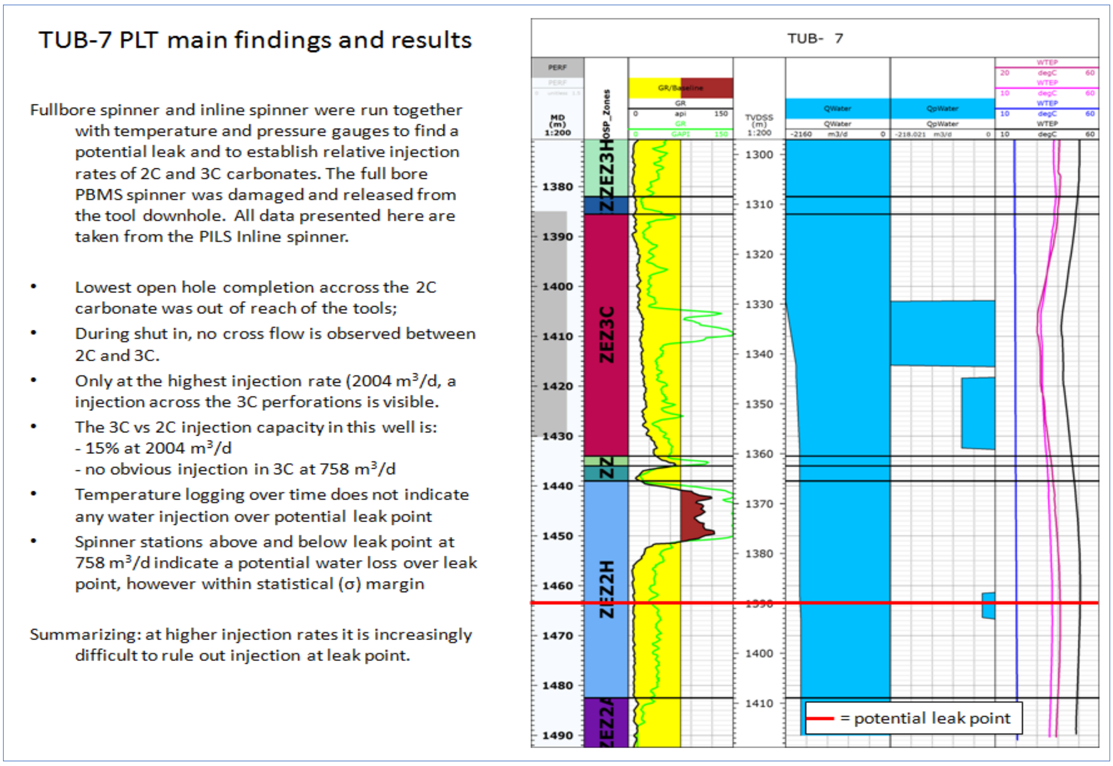
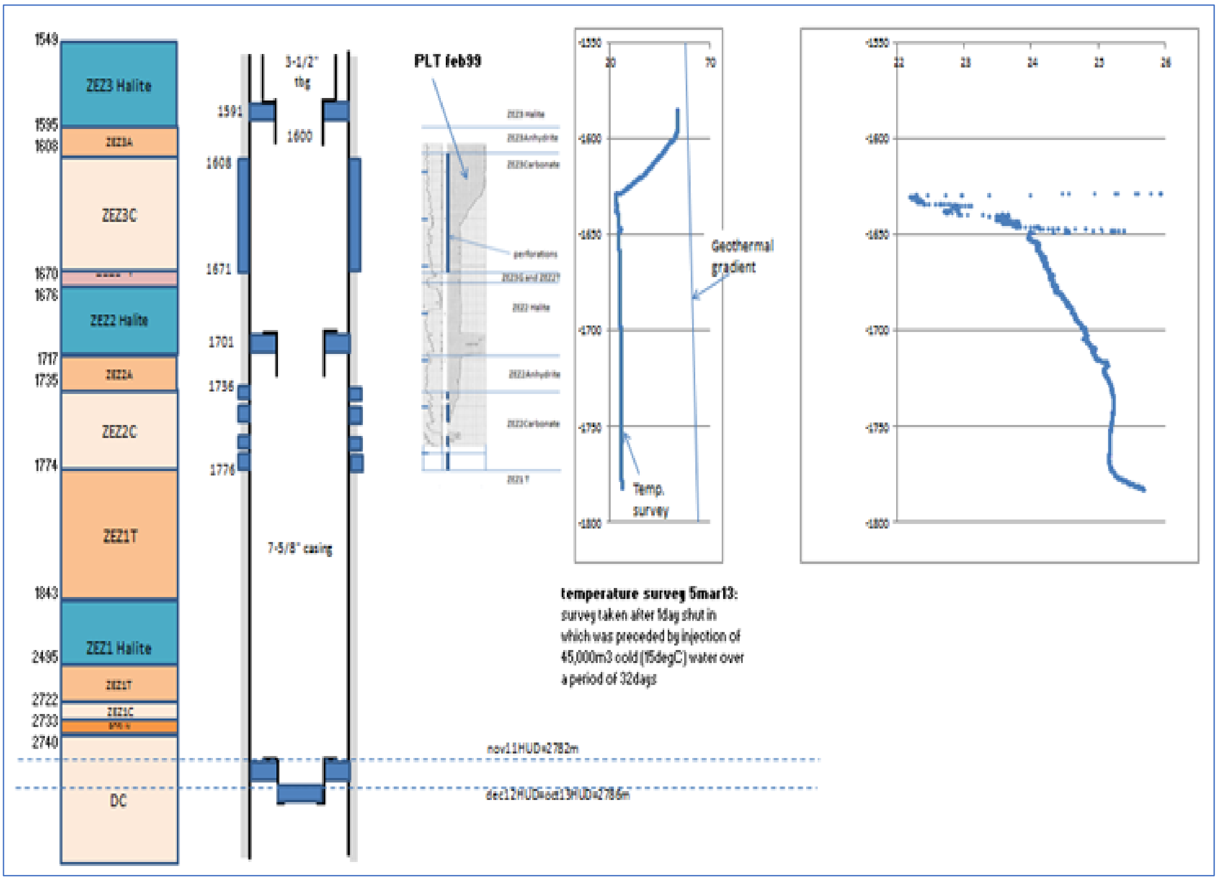


Figure B-5 – TUB-7 PLT results. Please note that the "potential leak point" at 1464 mAH-DFE was later found to be a baffle collar located in the 4-1/2" liner, which is not an issue wrt casing integrity. The spinner data is not conclusive. The temperature survey does not indicate water loss from the casing at that depth.

B.4 TUB-10



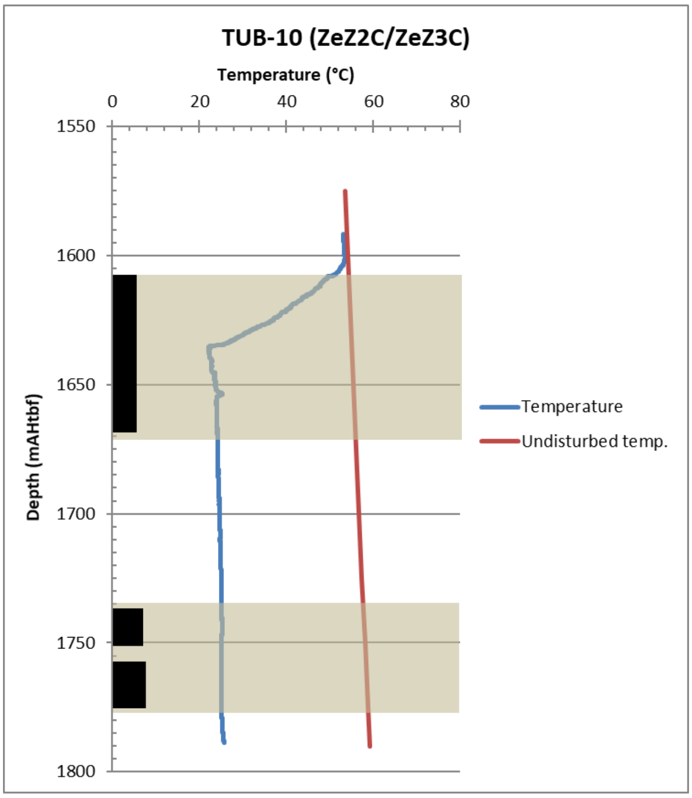


Figure B-6: TUB-10 temperature survey, December 2012

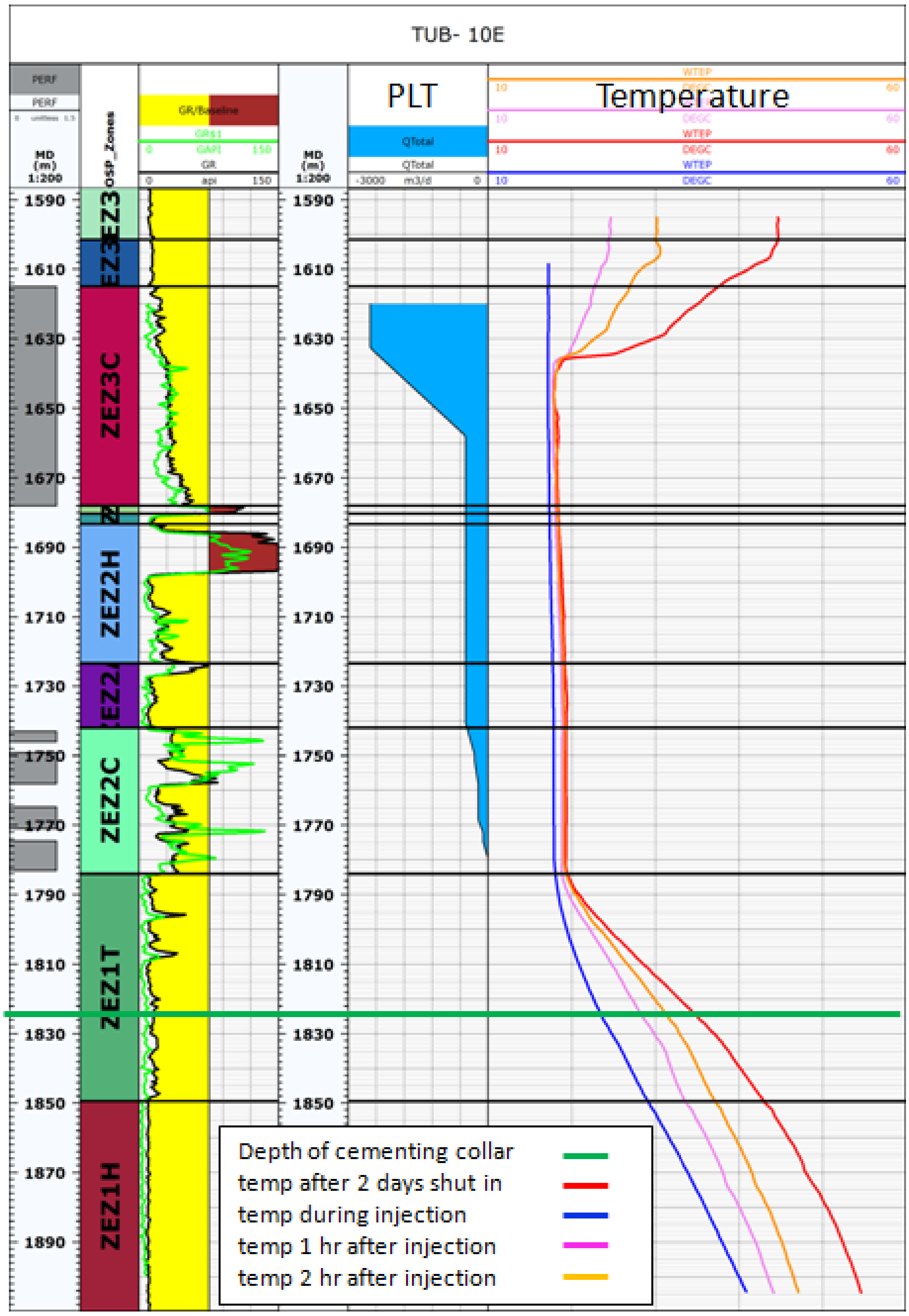
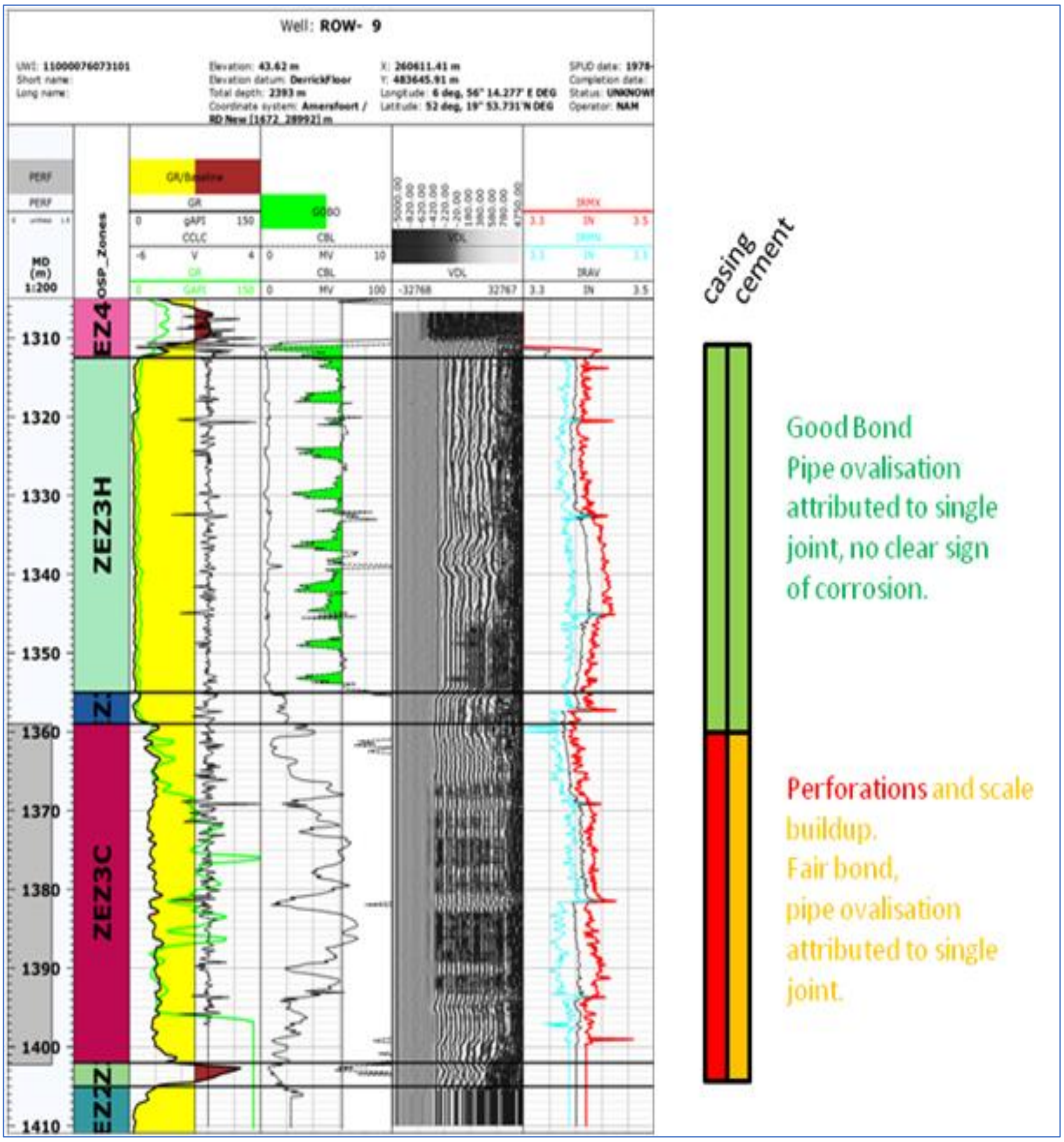


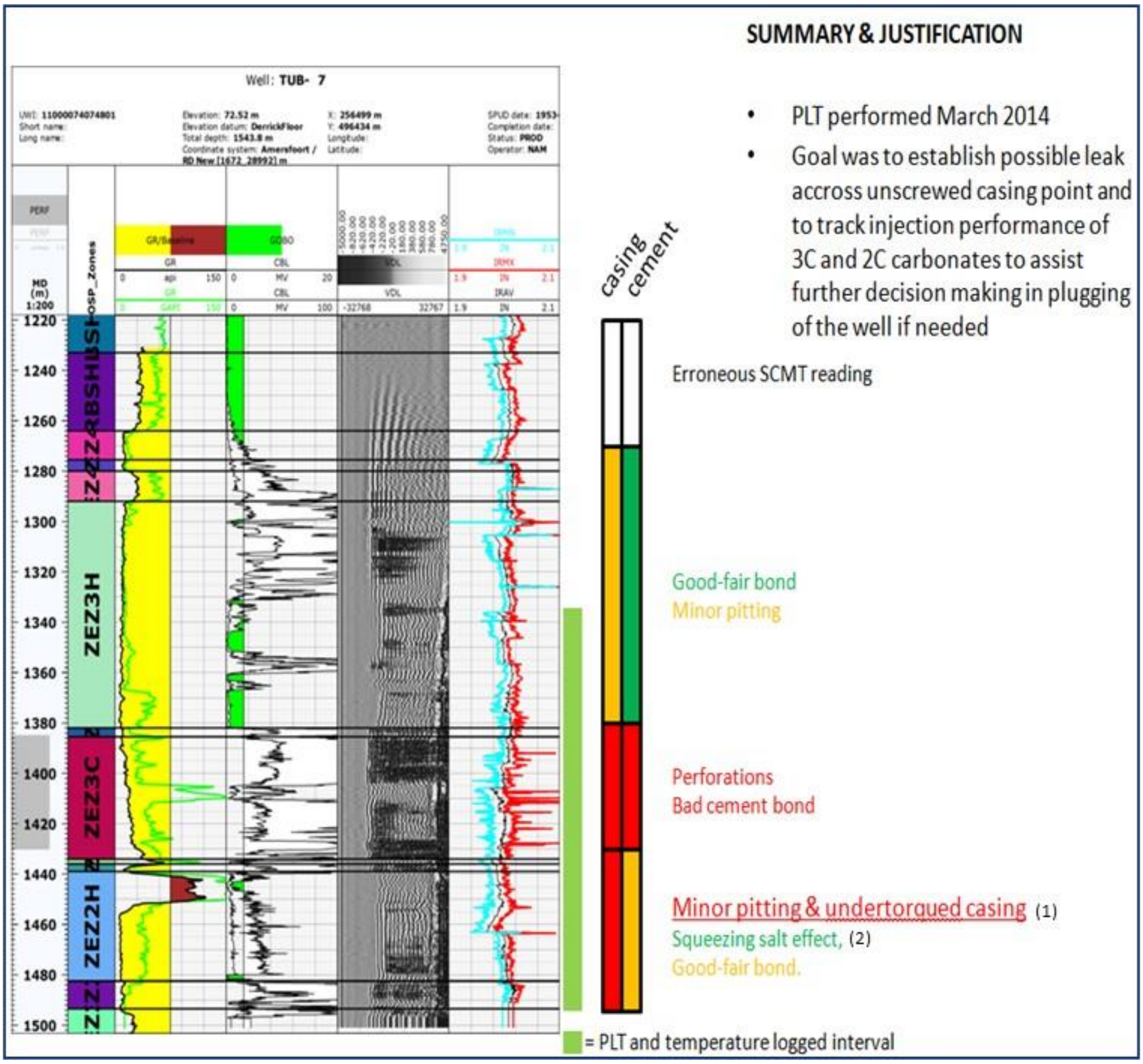
Figure B-7: TUB-10 PLT- and temperature survey, April 2015

Appendix C Caliper surveys and Cement Bond Logging

C.1 ROW-9



C.2 TUB-7



Notes:

(1) Suspected “undertorqued casing” was found to be a baffle collar in the 4-1/2” liner at 1464 mAH-DFE. The baffle collar does not present an issue for casing integrity. The combined data shows that leakage has not taken place.

(2) “Squeezing salt effect” was interpreted at a depth of 1440 mAH-DFE, at the top of the ZEZ2H layer. The interpretation is based on the excellent CBL quality and a very high attenuation of the VDL signal, however casing deformation was not observed.at this depth by the casing caliper.

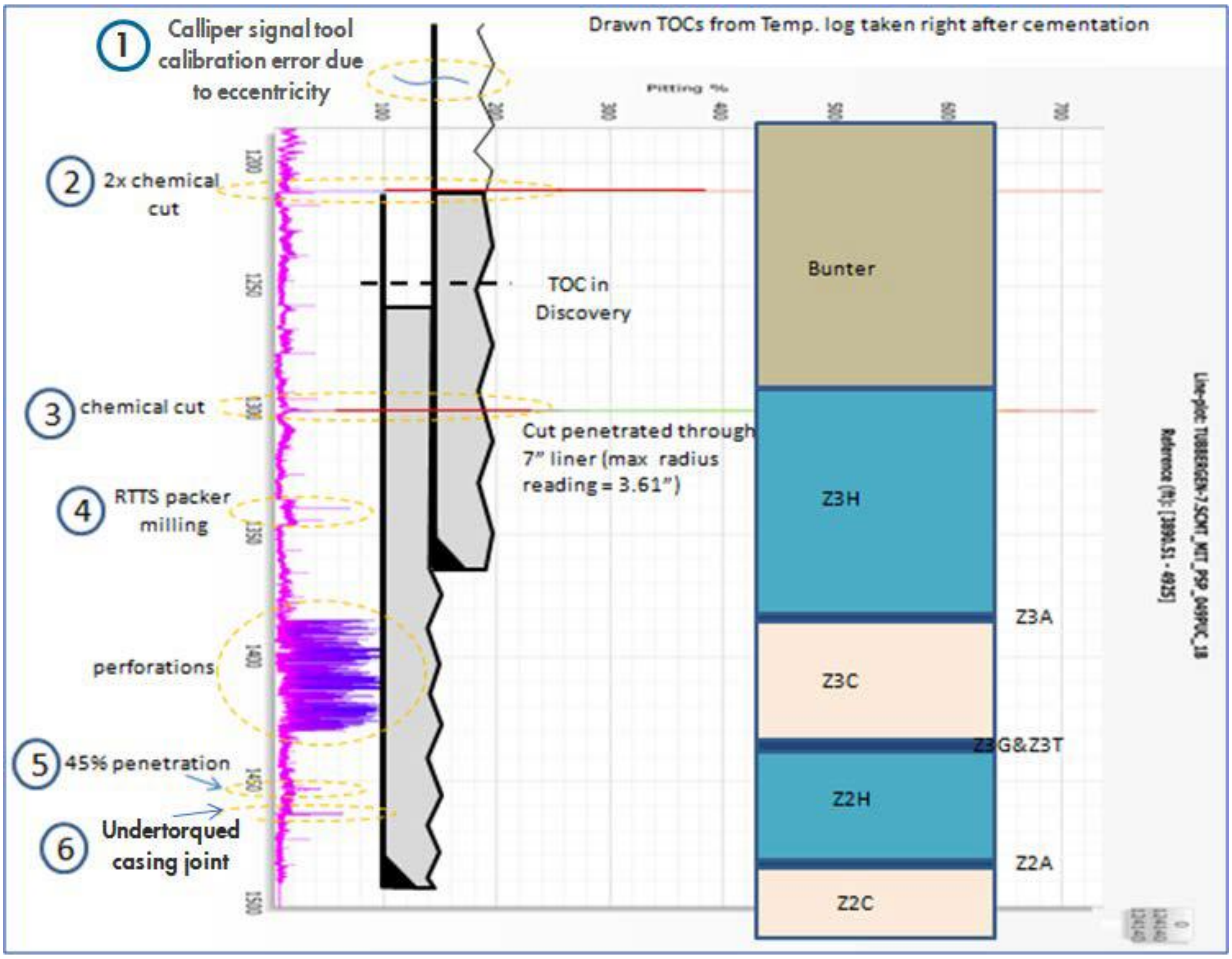


Figure C-1: PMIT-A caliper readings in TUB-7, Q4 2013

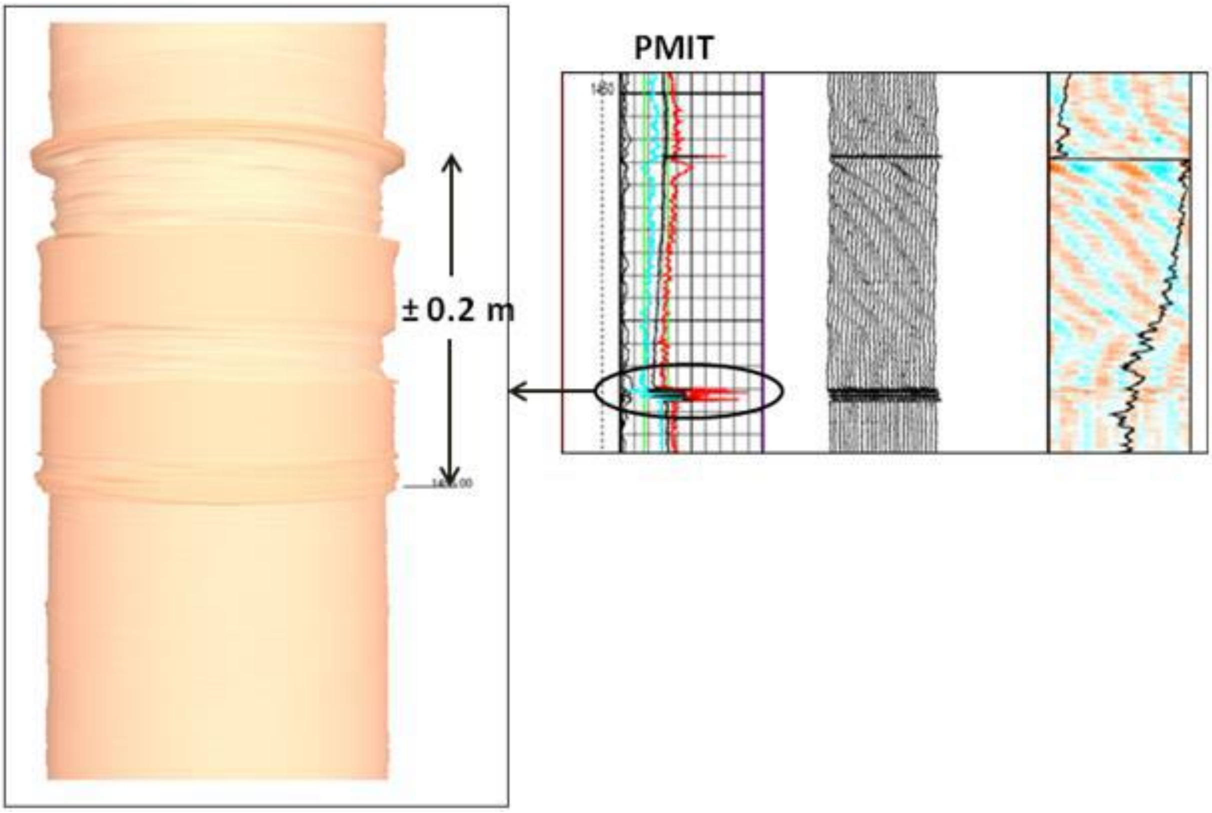
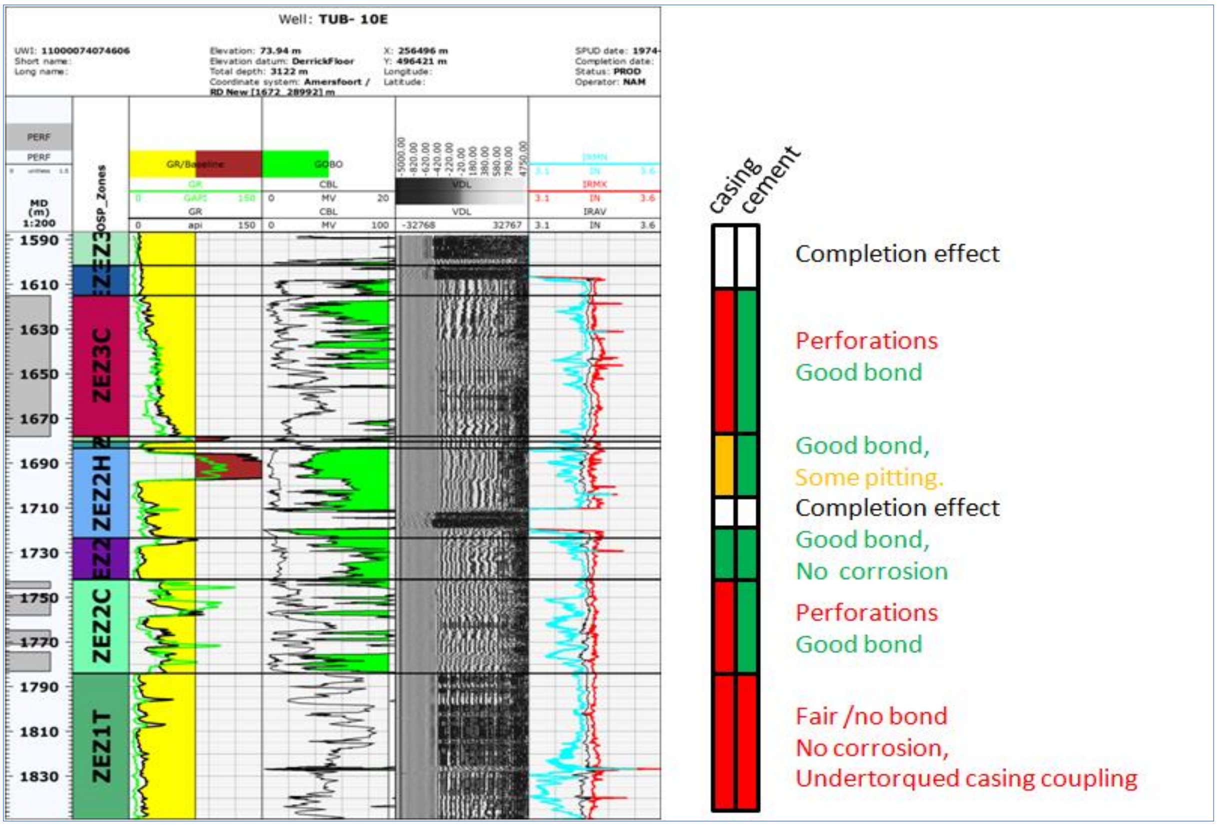


Figure C-2: 3D-caliper image of TUB-7 casing joint at 1464 mAHDF, Q4 2013. The ID profile changes are caused by the presence of a drilled-out baffle collar in the liner string.

C.3 TUB-10


Well: TUB- 10E
casing
cement
Completion effect
Perforations
Good bond
Good bond,
Some pitting.
Completion effect
Good bond,
No corrosion
Perforations
Good bond
Fair /no bond
No corrosion,
Undertorqued casing coupling

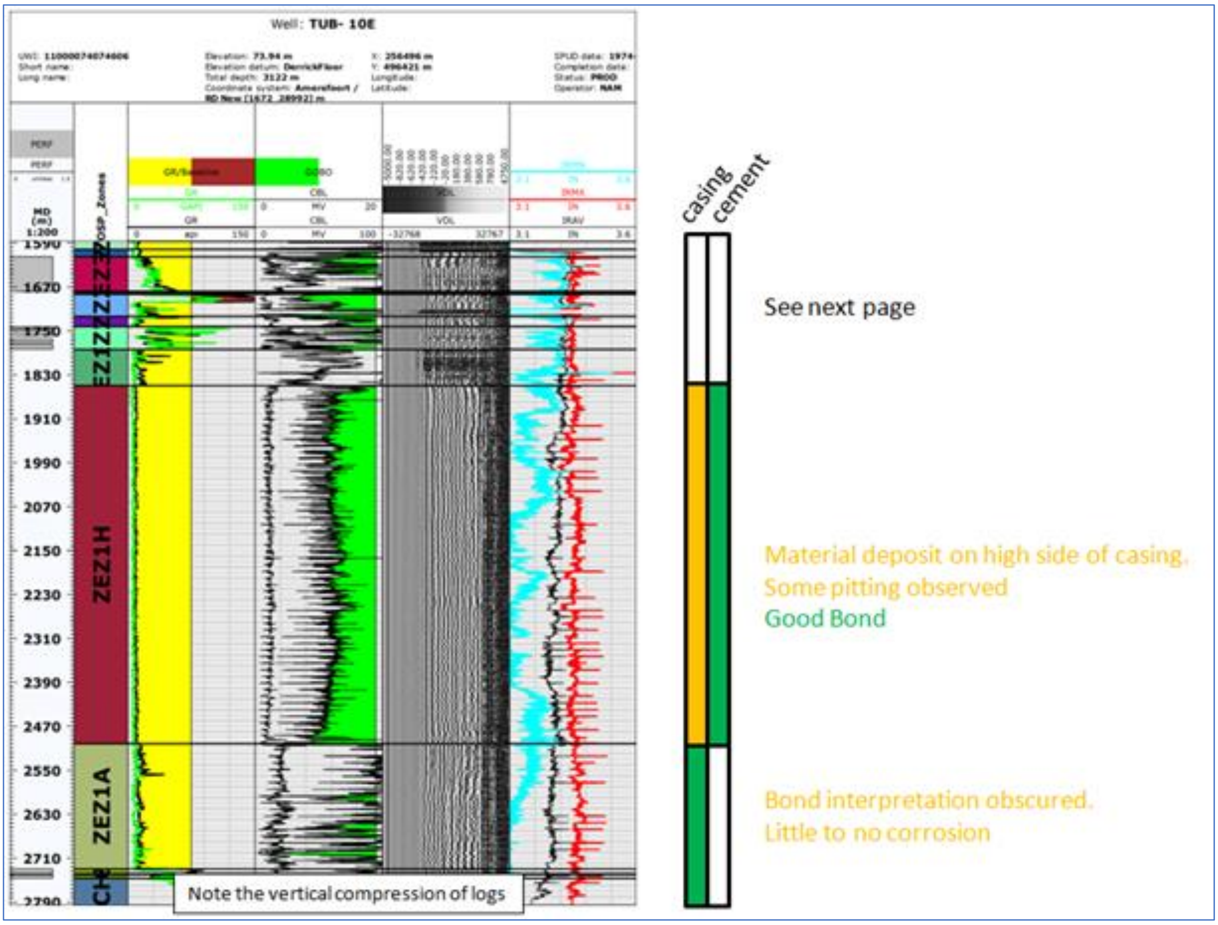

Well: TUB- 10E
casing
cement
See next page
Material deposit on high side of casing.
Some pitting observed
Good Bond
Bond interpretation obscured.
Little to no corrosion
Note the vertical compression of logs

Figure C-3: 3D-caliper image of TUB-10 casing joint at 1827 mAHDF, Oct 2013.

Appendix D Measured reservoir pressures

well	Date	Cum Well Injection [mln m3]	Datum pressure [bara]	measured pressure at top perforations [bar]
ROW-7	01/01/2009	0.00	11.7	11.6
ROW-7	28/11/2011	0.10	11.4	11.3
ROW-7	01/03/2012	0.11	11.3	11.2
ROW-7	06/03/2013	0.30	11.4	11.3
ROW-7	26/06/2013	0.35	11.4	11.3
ROW-7	17/07/2014	0.78	29.8	17.6
ROW-7	16/12/2015	0.87	29.6	17.4
ROW-7	03/11/2016	0.88	28.3	16.9
ROW-7	23/11/2017	0.98	40.6	29.5
ROW-7	11/10/2018	1.01	43.4	31.9
ROW-7	07/10/2020	1.10	41.8	29.3
ROW-9	01/01/2009	0.00	10.7	10.7
ROW-9	11/11/2011	0.05	29.4	36.6
ROW-9	14/11/2011	0.05	26.1	33.2
ROW-9	04/03/2013	0.24	27.1	34.2
ROW-9	02/07/2013	0.27	31.3	38.1
ROW-9	03/07/2013	0.27	29.4	36.5
ROW-9	08/01/2015	0.43	27.0	34.2
ROW-9	02/12/2015	0.47	17.0	17
TUB-10	01/01/2009	0.00	5.8	5.7
TUB-10	16/11/2011	0.06	21.4	2
TUB-10	21/11/2011		6.5	6.4
TUB-10	19/12/2012	0.45	5.2	5.1
TUB-10	26/03/2013	0.45	5.2	5.1
TUB-10	28/03/2014	0.74	31.3	12.6
TUB-10	02/10/2014	0.90	33.6	15
TUB-10	18/11/2015	1.24	36.1	17.3
TUB-7	01/01/2009	0.00	6.3	6
TUB-7	15/11/2011	0.03	6.6	6.3
TUB-7	28/02/2013	0.45	7.3	7
TUB-7	09/03/2014	0.64	7.7	7.4
TUB-7	19/03/2014		7.3	7
TUB-7	15/10/2015	0.64	6.9	6.8