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Nederlandse Aardolie Maatschappij

Technical evaluation of Twente water injection wells ROW-2, ROW-3, ROW-4, ROW-5 and ROW-7

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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 elke 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 voor de 2023 evaluatie, volgens het schema in het vigerend Waterinjectie Management Plan Twente 2022.

Table 0-1: Reproductie van Tabel 3 uit het Waterinjectie Management Plan, referentie [1], waarbij eerder onderzoek voor de verschillende putten wordt aangegeven met een referentie naar het bijbehorende rapport. De putten die worden behandeld in voorliggende 2023 rapportage zijn aangegeven met "x".

Put	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
TUM-1							[2]						
TUM-2							[2]						
TUM-3							[2]						
ROW-2							[2]						x
ROW-3				[3]			[2]						x
ROW-4				[3]			[2]						x
ROW-5							[2]						x
ROW-7				[3]						[4]			x
ROW-9				[3]						[4]			
TUB-7				[3]						[4]			
TUB-10				[3]						[4]			

Legend :

ingesloten

opgeruimd

Achtergrond

De Zechstein gasreservoirs waar water in geïnjecteerd wordt bestaan uit kalksteenlagen waarin van nature scheuren 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 anhydrietlagen zitten dikke, niet doorlaatbare lagen steenzout (haliet). De combinatie van een anhydriet en een 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 de 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 was de hoeveelheid water die is geïnjecteerd in Twente veel minder (4000-5000 m^3/d), omdat de productiesnelheid uit het Schoonebeek olieveld lager is dan oorspronkelijk verwacht.

In januari 2011 is gestart met waterinjectie. Na viereneenhalf jaar, in juni 2015, is de injectie tijdelijk gestopt, nadat door NAM werd vastgesteld dat door een lekkage van de watertransportleiding naar Twente een veilig en verantwoord transport van het injectiewater door de gehele leiding 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.

In injectieput ROW-2 werd in 2021 onverwachte schade aan de productiecasing geconstateerd, die niet kosteneffectief gerepareerd kon worden. ROW-2 is daarom buiten gebruik gesteld en de Zechstein reservoirs zijn geabandonneerd met een cement plug. NAM heeft een onderzoek naar de onderliggende oorzaak ingediend bij

SodM in mei 2021. In juni 2021 vroeg SodM aan NAM om aanvullend onderzoek te doen en de nabijgelegen put ROW-7 uit voorzorg stil te leggen. Een deel van het aanvullend onderzoek is door NAM in december 2021 bij SodM ingediend, en het resterende deel is in maart 2022 ingediend. Op 30 mei 2022 maakte SodM kenbaar dat het voorval in ROW-2 voldoende is onderzocht[1].

Om een herhaling van de gebeurtenissen rond put ROW-2 te voorkomen heeft SodM aan NAM gevraagd om een update te maken van het Waterinjectie Management Plan met extra surveillance stappen om de integriteit van de put beter te borgen. Deze update is door NAM in december 2021 bij SodM ingediend en in mei 2022 heeft NAM een update van de Overkoepelende Risico Analyse ingediend bij SodM.

Als onderdeel van de analyse rondom ROW-2 heeft NAM additionele surveillance gedaan op de waterinjectieputten, waarbij ook Pulsed Neutron Logs zijn genomen in 2021. Dit betrof een experimentele toepassing van een technologie die normaal gesproken wordt gebruikt om veranderingen in gassaturatie achter de casing te kunnen bekijken. In put ROW-4 werd een afwijking vastgesteld ter hoogte van de zoutlaag tussen de twee injectiereservoirs, wat kan duiden op pekel achter de buitenbuis. Bij een herhaalmeting in januari 2022 is dit bevestigd. In mei 2022 vroeg SodM om een nader onderzoek van deze metingen op put ROW-4. In juli 2022 heeft NAM een onderzoek naar de metingen op ROW-4 ingediend bij SodM, referentie [5], het Waterinjectie Management Plan verder aangescherpt om vroegtijdig zoutoplossing achter de buitenbuis van een put op te kunnen merken, referentie [1], en de Overkoepelende Risico Analyse verder geupdate, referentie [6].

Aan de hand van de Overkoepelende Risico Analyse en het aangescherpte Waterinjectie Management Plan concludeert SodM in september 2022 dat NAM de risicobeheersing van de injectie van productiewater in Twente op orde heeft. Put ROW-4 zal niet meer worden gebruikt voor waterinjectie. De huidige zoutoplossing vormt geen risico voor mens en milieu. SodM draagt de NAM op een herhaalmeting te doen naar de zoutoplossing bij ROW-4, om het verloop ervan beter te begrijpen. Pas na goedkeuring van SodM mag ROW-4 definitief gesloten worden. SodM oordeelt dat de waterinjectie in de putten ROW-5 en ROW-7 veilig plaats kan vinden[2]. Het aangescherpte Waterinjectie Management Plan is in oktober 2022 goedgekeurd door EZK. Hiermee is aan alle door SodM gestelde voorwaarden voldaan voor heropstart van de waterinjectie in Twente, referentie [7].

Evaluatie 2023

Het inspectie- en controleprogramma voor diverse waterinjectieputten wordt uitgevoerd conform het vigerende Waterinjectie Management Plan, dat onderdeel uitmaakt van de verleende vergunning. Volgens de voorschriften uit deze vergunning zijn de resultaten geëvalueerd over de afgelopen zes jaar voor waterinjectieputten ROW-2, ROW-3, ROW-4, ROW-5, ROW-7 en ROW-9. Voorliggend rapport bevat een gedetailleerde evaluatie van deze inspecties en testen en dient beoordeeld te worden door het bevoegd gezag. Als onderdeel van 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,
- de integriteit van het haliet (steenzout) achter de stalen verbuizing.

Uitkomst

Gedurende de periode dat water is geïnjecteerd tussen januari 2011 en december 2021 zijn de injectiedrukken, zoals 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 reservoirdrukontwikkeling in putten ROW-2, ROW-3, ROW-4, ROW-5 en ROW-7 is grofweg in lijn met de modelverwachting. Putten ROW-2 en ROW-7 zien een gedeelde drukontwikkeling en delen dezelfde reservoir opslagcapaciteit; deze zijn nu samengevoegd in één model. Put ROW-4 is ook verbonden met hetzelfde reservoir opslag volume, maar via een zeer langzame reservoir verbinding. Put ROW-4 heeft derhalve de beste drukmatch met het oorspronkelijke model. Put ROW-5 heeft zijn eigen opslagvolume volgens bestaand model. Er zijn er geen overschrijdingen geconstateerd van de drukken zoals in de vergunningen zijn vastgelegd.

[1] Brief aan NAM met oordeel over aanvullend onderzoek scheur buitenbuis: https://www.sodm.nl/documenten/brieven/2022/05/30/brief-aan-nam-met-oordeel-over-aanvullend-onderzoek-naar-scheur-in-injectiebuis-twente:
[2] Brief aan NAM met oordeel over ROW-4 en risicobeheersing waterinjectie Twente:
https://www.sodm.nl/documenten/brieven/2022/09/26/brief-aan-nam-met-oordeel-over-row-4-en-risicobeheersing-waterinjectie-twente

De injectiviteit in de reservoirs was 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 aan dat, zoals verwacht, het water vooral wordt opgenomen in een bestaand (natuurlijk) netwerk van scheuren in deze ondergrondse formatie. De injectiviteit in de putten ROW-2, ROW-5 en ROW-7 wordt beschouwd als erg goed, terwijl deze in put ROW-4 en ROW-9 matig tot goed is. De SRT's toonden ook aan dat er geen nieuwe scheuren worden gevormd als gevolg van de injectie. Daarom is de aanpak gewijzigd en gedocumenteerd in een actualisatie van het Water Injectie Management Plan. Als onderdeel hiervan worden er geen SRT's meer afgenomen. Mocht er op basis van oppervlakte data (injectie druk en snelheid) aanwijzingen worden gevonden dat dit verandert, kunnen de SRT's weer worden hervat. ROW-3 is de enige put waar water in een zandsteenlaag wordt geïnjecteerd en deze ligt op grotere diepte dan de kalksteen en steenzoutlagen. In tegenstelling tot het Zechstein Carbonaat heeft dit oude gasreservoir geen natuurlijk netwerk van scheuren. De injectiviteit bleek zodanig laag dat waterinjectie in put ROW-3 gestopt is in 2015.

In de MER en vergunningsaanvragen is destijds de nodige aandacht besteed aan het mogelijk oplossen van de bovenliggende steenzoutlaag (haliet) 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[3]. 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 steenzout of tot 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. Dit was het geval in ROW-4.

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

1. Temperatuur. Omdat de temperatuur van het injectiewater lager is dan de temperatuur in de diepe ondergrond zijn de zones waar water in geïnjecteerd is iets afgekoeld. Met behulp van speciale apparatuur is in de put de temperatuur gemeten. Echter, om ervoor te zorgen dat de apparatuur zonder problemen in de put af kan dalen, wordt er vlak voor de metingen heet water in de put geinjecteerd. Dit maakt de interpretatie van de temperatuur data erg complex.

   De temperatuurmetingen die in alle waterinjectieputten zijn uitgevoerd geven aan dat het water op de juiste plaats van het reservoir wordt geïnjecteerd en geven geen indicatie dat het steenzout aan het injectiewater is blootgesteld. Gegeven de lage resolutie van deze metingen en door verstorende effecten ten gevolge van de operationele procedures zoals hierboven beschreven, kunnen de temperatuur metingen geen kleinschalige lekkages vaststellen.

2. Cementkwaliteit. Een indicatie van de kwaliteit van de cementenwand die buitenom de gehele waterinjectieput zit, wordt verkregen met behulp van zogenaamde Cement Bond Logs (CBLs). CBLs tonen aan of een vaste stof in direct contact staat met de verbuizing. Mocht blijken dat de cementkwaliteit onvoldoende is dan bestaat de mogelijkheid dat injectiewater terecht komt achter de verbuizing. Water wordt echter slechts daar geïnjecteerd waar geen aanleiding is om te vermoeden dat injectiewater achter de verbuizing in contact kan komen met zout.

   Uit de stand-alone CBLs blijkt dat de waterinjectieput- en cementcondities goed zijn. Echter, bij het analyseren van een time-lapse CBL in put ROW-4 bleek op de plek van de zout oplossing ook een afname in de Cement Bond.

3. Wanddikte. 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 caliper metingen van de verbuizing die door de jaren heen (2011-2023) in de ROW putten zijn uitgevoerd, geven aan dat de wanddiktes redelijk stabiel zijn. De sterkte

[3] 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)

is voldoende voor de drukken waaraan de verbuizingen worden blootgesteld. Er zijn geen lekkages vastgesteld.

Voor alle waterinjectieputten is vastgesteld dat de wanddiktes van de injectiebuizen voldoende zijn om de maximale verwachte injectiedruk te weerstaan.

4. Ingegriteit achter de verbuizing. Met time-lapse PNL metingen kunnen veranderingen achter de verbuizing worden opgemerkt die kunnen duiden op oplossing van de halietlaag (steenzout) zoals vastgesteld bij put ROW-4. De 2023 PNL herhaalmeting toont aan dat er geen voortzetting van zoutoplossing heeft plaatsgevonden sinds de injectie is gestopt.

Conclusie

Geconcludeerd mag worden dat alle in de vergunning genoemde inspectie- en testprogramma's, zoals beschreven in het Waterinjectie Management Plan, volgens plan zijn uitgevoerd. Met de aanscherping van het Waterinjectie Management Plan en de Overkoepelende Risico Analyse bieden de in de vergunning genoemde beheersmaatregelen van het waterinjectie-programma goede waarborgen voor een veilig en verantwoord opereren van de waterinjectieputten: waterinjectie in de putten ROW-5 en ROW-7 kan veilig plaats vinden. Put ROW-2 is subsurface (op diepte) geabandoneerd, en put ROW-4 zal niet meer worden gebruikt voor injectie. Na goedkeuring van SodM mag ROW-4 definitief afgesloten worden.

Management summary

In compliance with the various water injection permits that were granted in 2010 for the 7 locations (TUM1, TUM2, ROW2, ROW3, ROW5, 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 caprock 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 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 [3]. This report presents the evaluation for ROW-2, ROW-3, ROW-4, ROW-5 and ROW-7, as per the schedule in the prevailing Water Injection Management Plan 2022.

Main conclusions from the 6-yearly technical evaluation are:

- In well ROW-2 a casing shear was observed during a work-over in 2021. This could not be cost-effectively repaired and the well was abandoned with a cement plug.
- In response to the ROW-2 well failure NAM carried out additional surveillance on the remaining Rossum-Weerselo injectors, including an experimental application of PNL logging to survey for well integrity behind the casing. Halite dissolution was observed in between the two injection reservoirs at well ROW-4. From time-lapse measurements it was concluded that the observed dissolution is related to injection: no changes were observed between measurements in 2022 and 2023 when injection had been stopped. Well ROW-4 will no longer be used for water injection.
- Wells ROW-3 and ROW-9 are suspended and are no longer used for water injection. Evaluation of their injection history proved good integrity.
- Well ROW-5 and ROW-7 (currently hooked up and closed-in) are in reasonable condition and can be used for future water disposal.
- The monitoring programs were updated following the ROW-2 and ROW-4 events. The updated 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 current average pressure is still significantly lower than the original reservoir pressures.
- 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 reservoir pressure increase as a function of cumulative amount of water injected behaves roughly in line with the models. Wells ROW-2 and ROW-7 see the same reservoir pressures and share the same reservoir storage capacity, they have now been lumped together in a single model. Well ROW-4 is also connected to the same reservoir storage volume, pressure monitoring shows how well ROW-7 is now aligned with the pressure in ROW-4. However, the reservoir connection is baffled, it took some 1-2 years for the pressure to equilibrate since injection was shut-in. The best match for ROW-4 is achieved with its original model. Well ROW-5 has its own storage space as per the original model.
- The step-rate test (SRT)-plots derived from the injectivity tests all indicated 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, Reference [8]. 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 took 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, Reference [9] and [10]. These studies have been independently reviewed by academic experts under auspices of State Supervision of Mines[4]. From halite dissolution modelling it was concluded that potentially this can only occur near the injection well in case of a leak path behind a production casing with a poor cement bond which would allow injection water to directly flow past the halite formation. This was found to be the case for well ROW-4.

Temperature surveys, cement bond logging, casing caliper surveys and PNL logging have been executed to check if injection water potentially exposes the ZEZ-Halite layers. From the logging the following is concluded:

- Downhole temperature surveys indicated in 2013 that injection was restricted to the targeted Zechstein-Carbonate reservoirs. Given the low resolution of these measurements and due to effects resulting from the operational logging procedures, the temperature measurements cannot detect small-scale leaks.
- Cement bond logs showed good cement integrity and regular casing caliper surveys indicated good casing quality across the confining halite seal layers.
- With time-lapse PNL measurements it is possible to screen for changes in the halite behind casing. Such was observed at well ROW-4, and the well was stopped for injection. The repeat PNL in 2023 demonstrated that no further changes have occurred since, and hence that salt dissolution is related to injection.

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

- Tubing strength calculations show that tubing integrity exceeds the minimum requirements for safe operations. All wells show sufficient wall thickness to withstand the pressures experienced during water injection under current conditions. No tubing leaks are detected.
- During the current evaluation period all A-, B- and C-annulus pressures have remained below their Maximum Allowable Annular Surface Pressure (MAASP).
- Pressure data demonstrate full pressure isolation between the tubing, A-annulus and B-annulus.

[4] 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)

1 Introduction

In compliance with the various water injection permits that were granted in 2010 for the 7 locations[5] 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 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 (WMP), Reference [1]. 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 WMP, a technical evaluation is done every six years from start of injection. However, as can be seen from Table 1-1, the first technical evaluation was carried out already after 3 years in 2014/2015. That 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. The remaining set of wells was evaluated as per the regular 6-yearly cadence in 2017 (TUM-1, TUM-2, TUM3 and ROW-2 and ROW-5) and also wells ROW-3 and ROW-4 were included in this evaluation. Wells TUB-7, TUB-10, ROW-7 and ROW-9 were evaluated again in 2020. The evaluation reports for these wells were shared with the regulator (Ministry of Economic Affairs/SodM), References [3], [2] and [4].

In the 2022 update of the WMP the review table was updated: given that no new information becomes available from long-term suspended or abandoned wells, there is no added value in including those wells in a six-yearly review. Wells TUM-1, TUM-2 and TUM-3 were suspended since 2016 and have been subsurface abandoned in 2021. No new data became available since the last review in 2017. Similarly, wells TUB-7 and TUB-10 have been suspended since 2015/2016. By including all ROW wells in this current 2023 evaluation, the staggered review cycle is harmonized again into a single 6-yearly batch. No new information is available for wells ROW-3 and ROW-9. In future 6-yearly reviews, only wells ROW-4, 5 and -7 will need to be analyzed.

Table 1-1: Overview of historic and current 6-yearly reviews. Previous reviews for the various wells are indicated as a reference to the associated report. The wells that are covered in this 2023 report are indicated with "x".

Put	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
TUM-1							[2]						
TUM-2							[2]						
TUM-3							[2]						
ROW-2							[2]						x
ROW-3				[3]			[2]						x
ROW-4				[3]			[2]						x
ROW-5							[2]						x
ROW-7				[3]						[4]			x
ROW-9				[3]						[4]			
TUB-7				[3]						[4]			
TUB-10				[3]						[4]			

Legend :

suspended

abandoned

[5] Injection locations: TUM1, TUM2, ROW2, ROW3, ROW5, ROW6 and TUB7

Figure 1-1 highlights the previous reviews against the cumulative injection for the ROW wells. Wells ROW-3 and ROW-9 have not been used since the integrity issues with the water export pipeline in 2015. Wells ROW-3, ROW-5 and ROW-7 remain available for future water injection. Note that all ROW and TUB wells in Table 1-1are now suspended with plugs installed in the wellbore. The TUM wells have been permanently abandoned since Q3-2021.

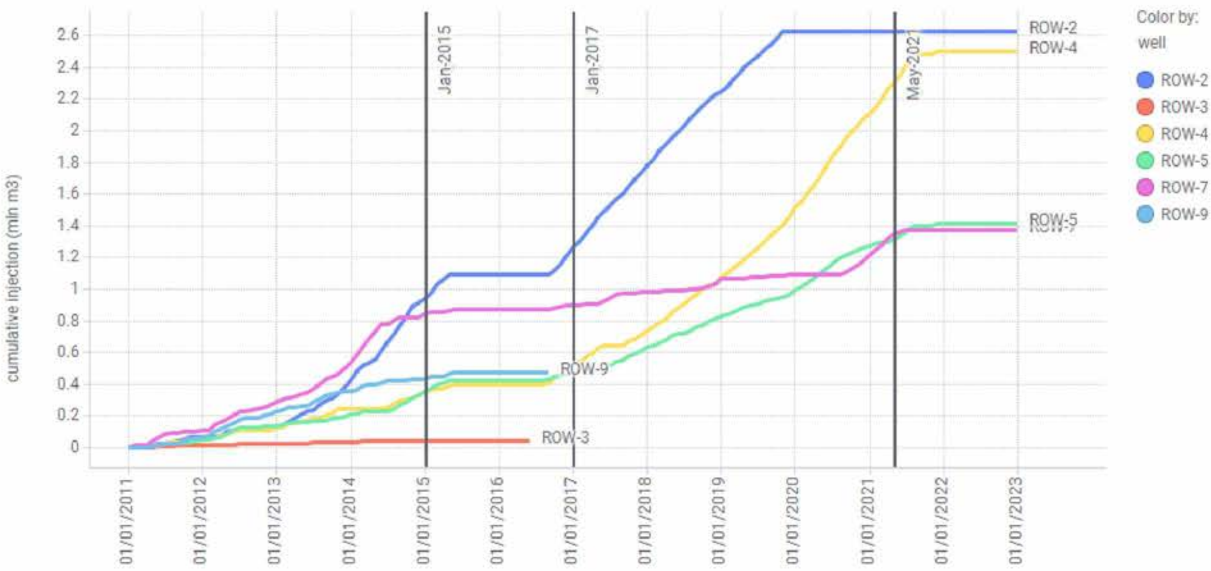

Figure 1-1: Cumulative injection for ROW-7/9 and TUB-7/10. The issue dates of the previous 6-yearly reviews are indicated as vertical lines.

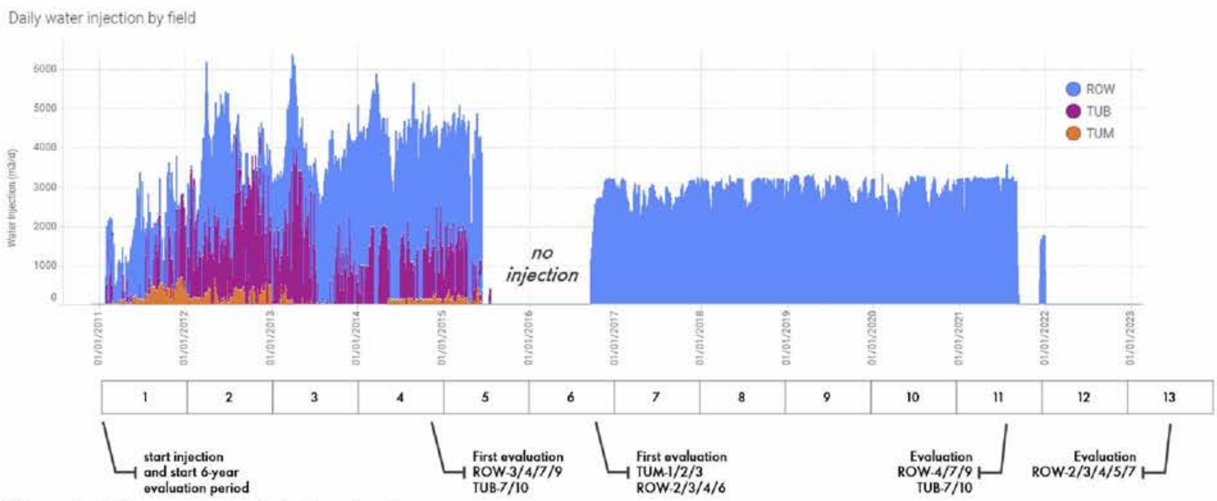

Figure 1-2: Twente water injection timeline

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 [11].

As Figure 2-1 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.

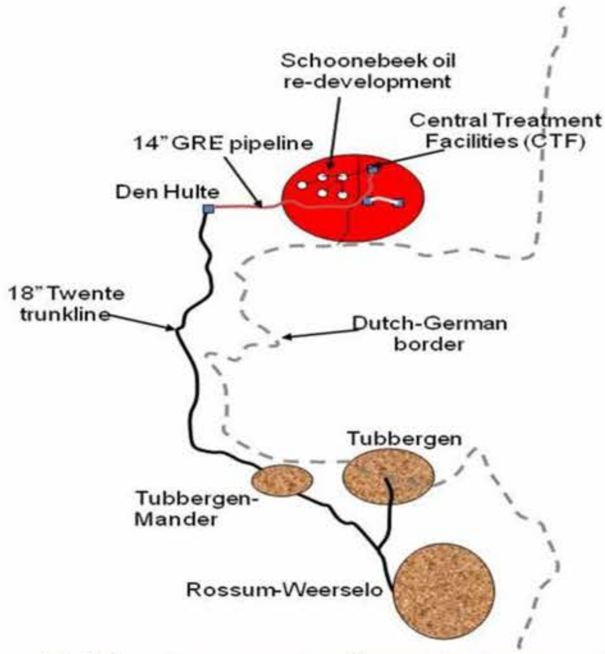

Figure 2-1: Schematic representation of water injection system within Schoonebeek Oilfield production system

The transported water arrives at the Twente wellsites 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.

From the Twente wellsites 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

Except for well ROW-3 (which injects into sandstone in the Limburg formation), all wells under review in this report inject into the naturally fractured Zechstein Carbonate formation. Here the reservoir seal is provided by the overlying Zechstein salt (Halite) layers. The injection wells are connected to two Zechstein Carbonate reservoirs, namely the ZEZ2C and ZEZ3C (except for ROW-2, which is only connected to the ZEZ2C). 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 2023 is discussed and compared to the plan as it was presented in the water injection FDP, Reference [12].

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.

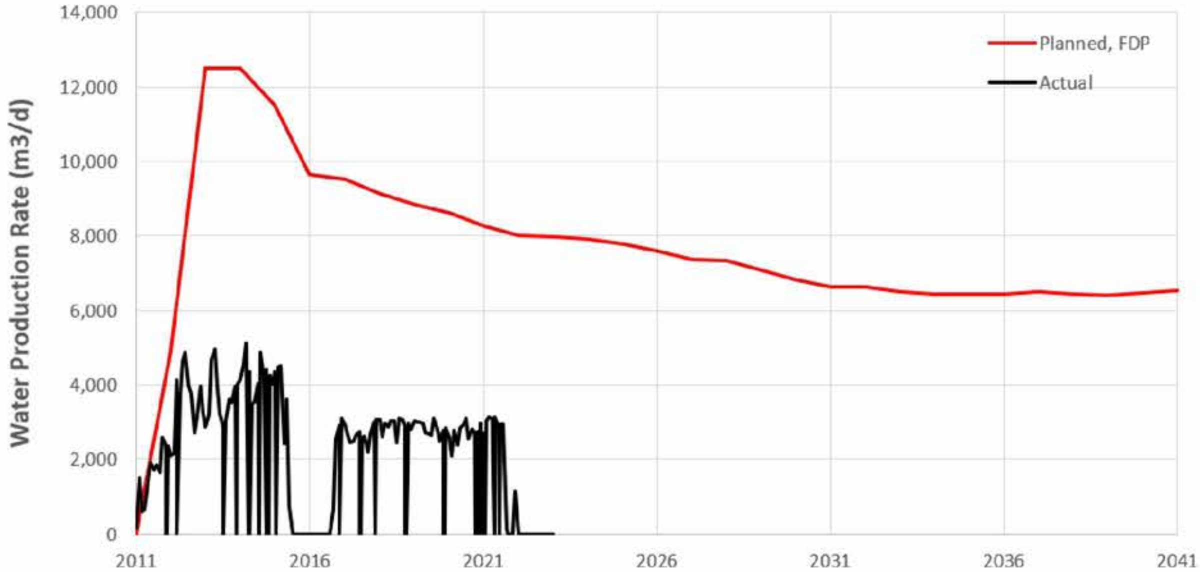

Figure 3-1: Actual water injection rates compared to planned in FDP

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 2011 until December 2022. 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.

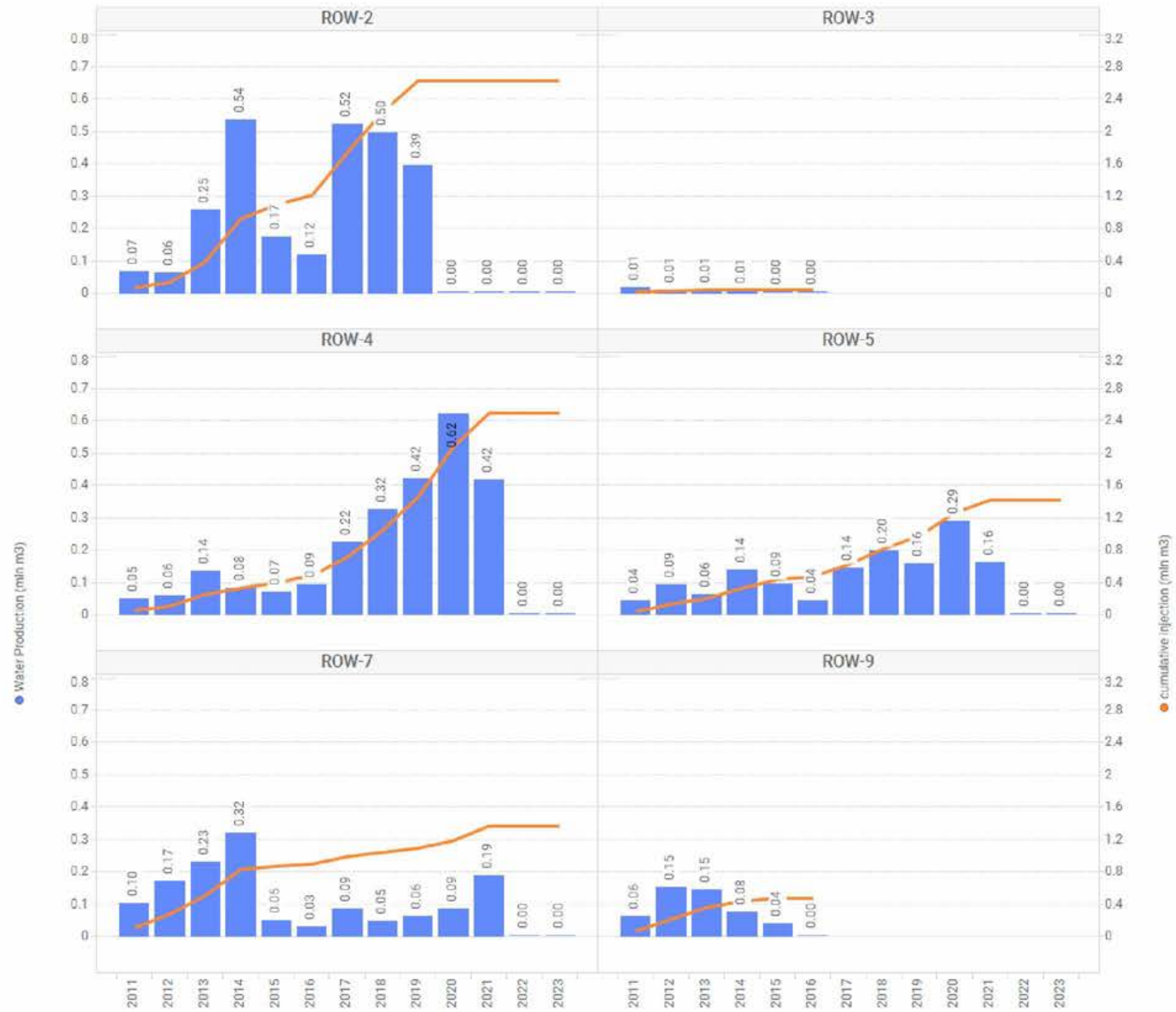

Figure 3-2: Annual (left hand scale) and cumulative (right hand scale) injection volume for the evaluated water injection wells (up to 31/12/2022)

Table 3-1: Cumulative injected water volume per location until 31/12/2022 in comparison with the allowed volume according to the water injection permit for each location[6].

	location	ROW2		ROW3		ROW5	ROW6
	well	ROW-2	ROW-7	ROW-3	ROW-4	ROW-5	ROW-9
year	2011	0.065	0.101	0.015	0.051	0.041	0.062
	2012	0.062	0.168	0.009	0.060	0.087	0.149
	2013	0.255	0.231	0.010	0.135	0.063	0.145
	2014	0.536	0.318	0.005	0.084	0.137	0.076
	2015	0.174	0.049	0.004	0.068	0.094	0.039
	2016	0.120	0.030	0.000	0.092	0.042	0.000
	2017	0.524	0.085	0.000	0.223	0.145	0.000
	2018	0.497	0.047	0.000	0.324	0.197	0.000
	2019	0.395	0.062	0.000	0.421	0.159	0.000
	2020	0.000	0.085	0.000	0.620	0.289	0.000
	2021	0.000	0.189	0.000	0.418	0.160	0.000
	2022	0.000	0.000	0.000	0.000	0.000	0.000
cumulative by well		2.626	1.365	0.044	2.495	1.414	0.471
cumulative by location		3.991		2.540		1.414	0.471
permitted cumulative		19.1		7.8		6.59	1.61

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

4 Water injection and integrity of reservoir confining seals

4.1 Introduction

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.

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 downhole injection pressure 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:

  $$THPi_{max} = FG_{seal} \times TVD_{bottom\ seal} - P_{hyd}$$

  in which:

  - $THPi_{max}$ = the surface injection pressure limit (bar)
  - FG_{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, a safety margin of 10% is applied. Furthermore, it is assumed that the entire wellbore is filled with water[7].

- **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.

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

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.

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. As described in Reference [13], 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, and gravity (depending on the height of the injector on the structure, Figure 4-5 and Figure 4-6). The combination of these dynamic effects typically yields a higher measured local pressure than the average reservoir pressure. Longer well shut-in times prior to the pressure survey allow for the wellbore pressure to equalize and approach the far-field reservoir pressure. In case the injectivity is moderate or poor, the pressure at the wellbore will take longer to equalize with the average reservoir pressure. This behavior is particularly pronounced for well ROW-4 in 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 8.4 mln m^3 which is 24% 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. However, the reservoir has been through a long period of pressure equilibration since cessation of injection per 1/1/2022. Figure 4-1 and Figure 4-2 give an overview of the reservoir pressures (at datum) in time and versus the cumulative field water injection. The expected development of reservoir pressure as a function of injected water volume was predicted prior to actual injection for each well. An important input to this prediction is the water storage capacity, as determined for each well by dividing the total amount of gas produced with the original gas formation volume factor, References [14] and [15]. Figure 4-3 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 C. It can be seen from Figure 4-3 that the reservoir pressure increase as a function of cumulative amount of water injected behaves roughly in line with the models, with some imprint of aforementioned dynamic effects. Figure 4-1 clearly shows how wells ROW-2 and ROW-7 share the same reservoir pressure trend. They are both connected to (and fill up) the same reservoir storage space, which can be expected given their mutual proximity (Figure 4-7). Appendix B of Reference [16] provides further details on the dynamic behavior of the Rossum-Weerselo reservoir. By lumping ROW-2 and ROW-7 in a single model, the pressure mismatch for the more recent data points in ROW-7 is significantly improved, see Figure 4-4. Well ROW-4 is also connected to the same reservoir storage volume, pressure monitoring shows how well ROW-7 is now aligned with the pressure in ROW-4. However, due to a baffled reservoir connection it took some 1-2 years to equilibrate since injection was shut-in. The best match is achieved with its original model. Well ROW-5 is on a distinctly different pressure trend and shows a reasonable match with the original model.

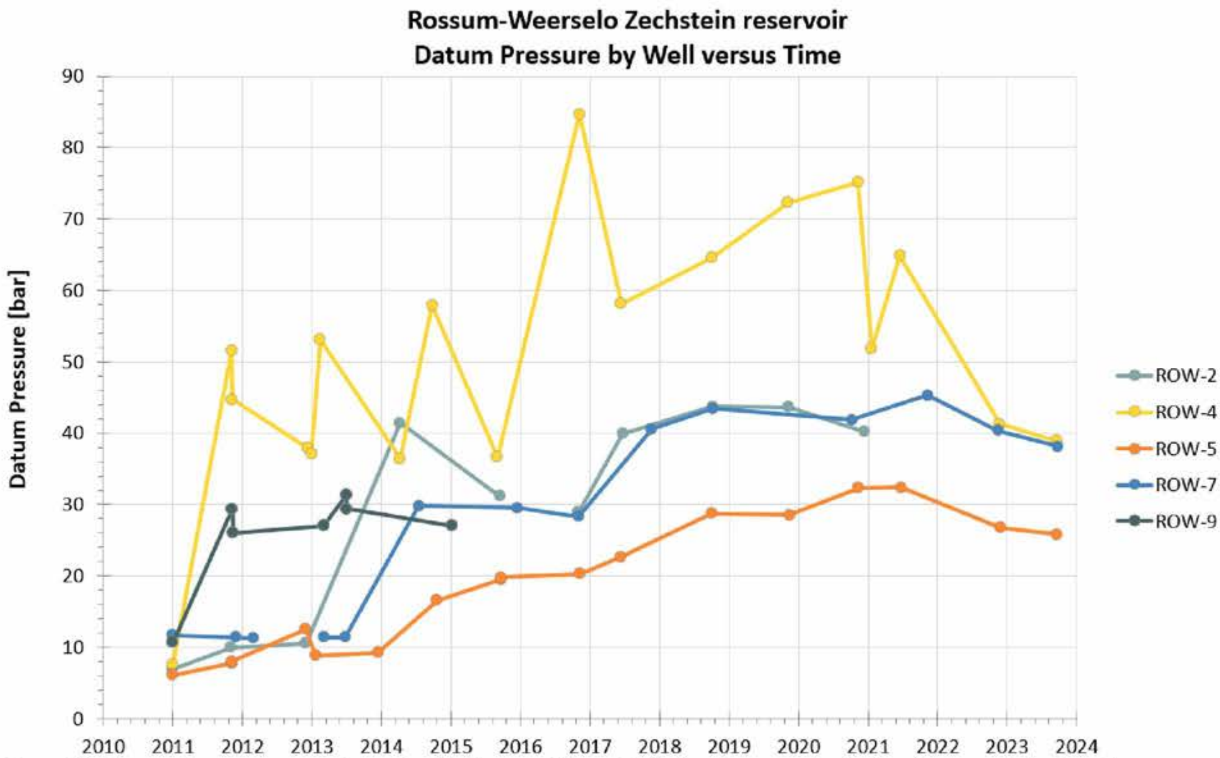

Figure 4-1: Reservoir pressures at datum for the Rossum-Weerselo Zechstein reservoir during the water injection phase as a function of time

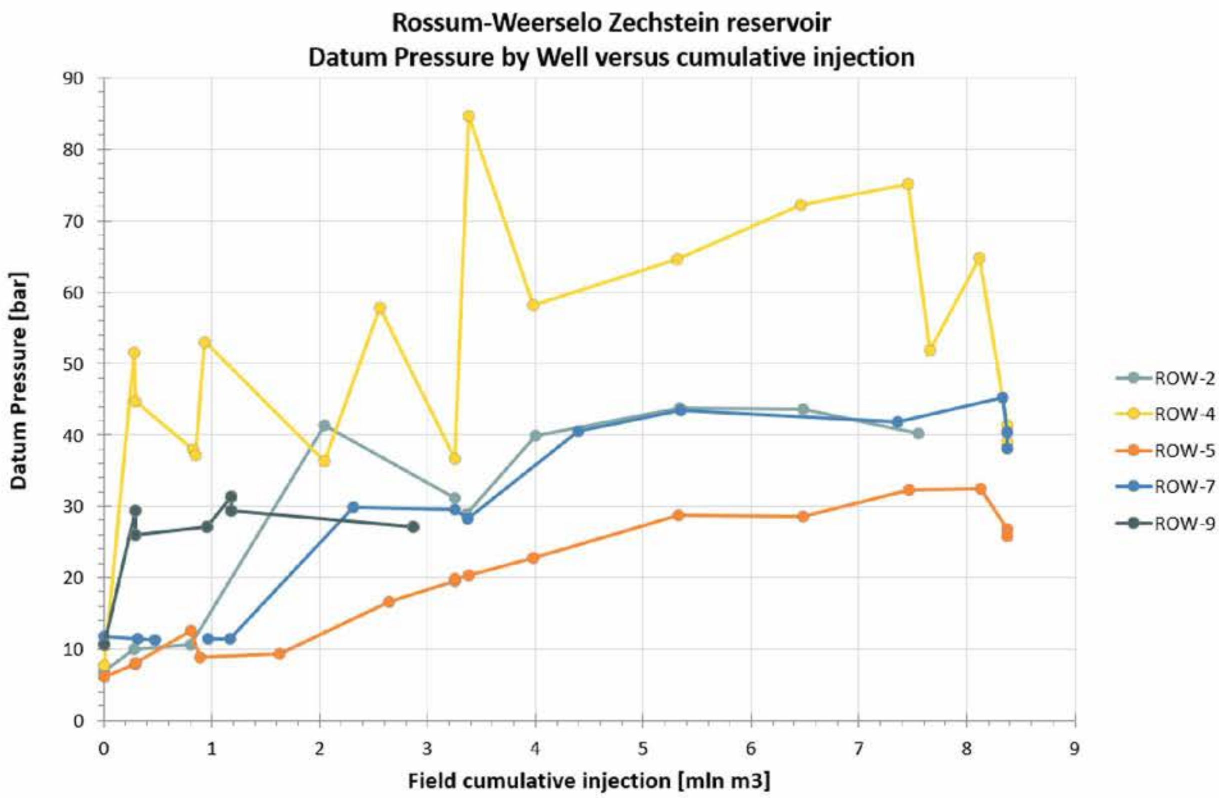

Figure 4-2: Reservoir pressures at datum for the Rossum-Weerselo Zechstein reservoir during the water injection phase as a function of the cumulative reservoir injection volume.

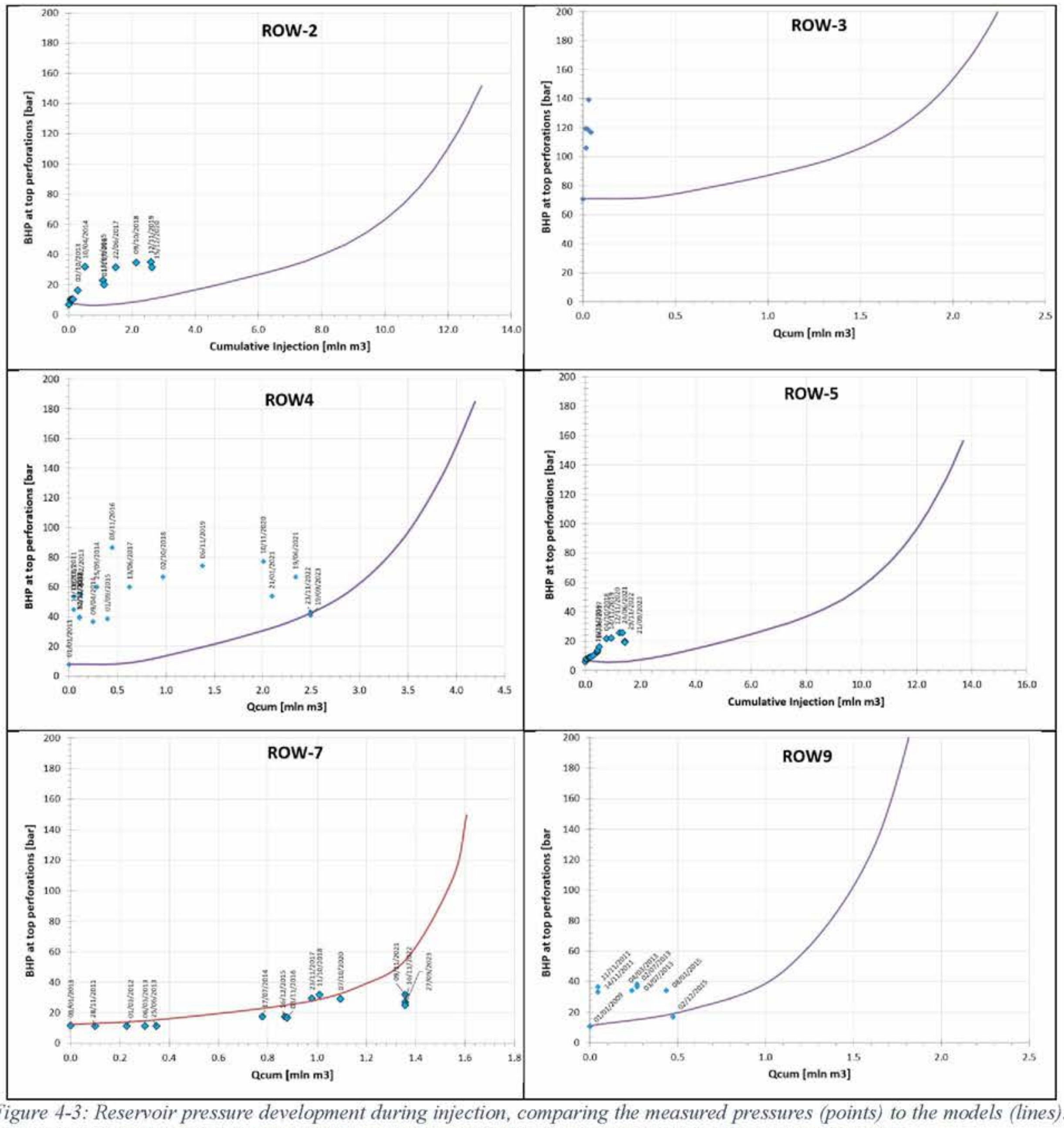

Figure 4-3: Reservoir pressure development during injection, comparing the measured pressures (points) to the models (lines). Note: all measured bottomhole pressures have been converted to top reservoir depth of their respective wells.

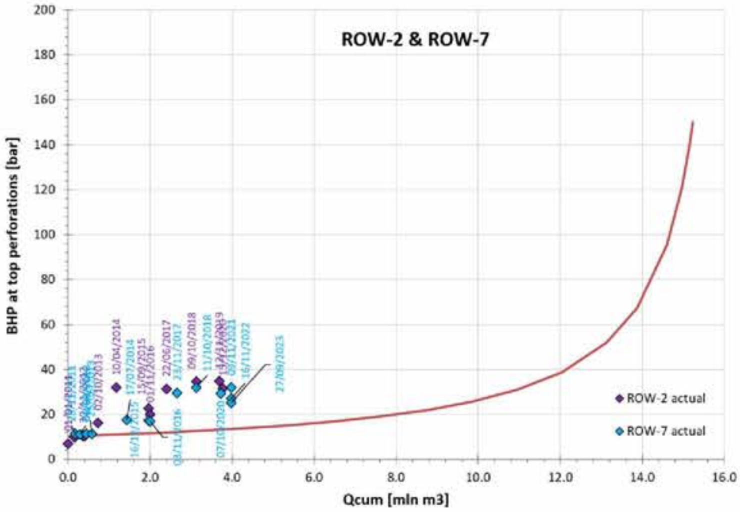

Figure 4-4: Reservoir pressure development during injection for the combined reservoir storage in ROW-2 and ROW-7, comparing the measured pressures (points) to the models (lines).

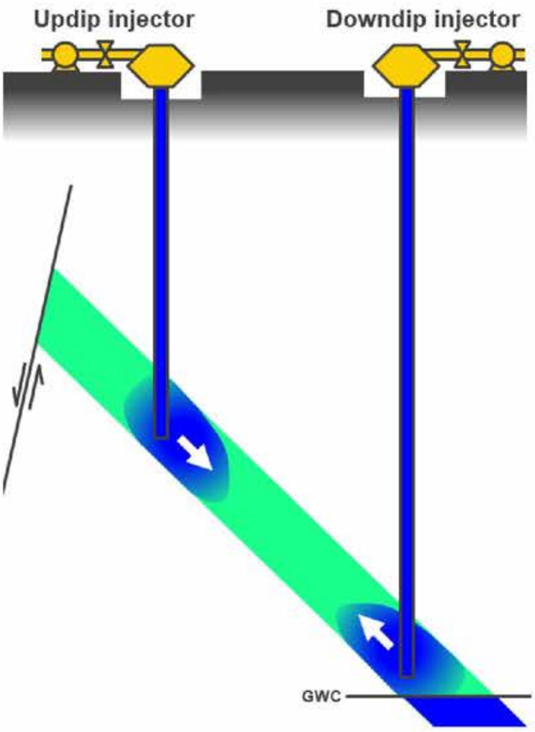

Figure 4-5: Schematic cross-section to illustrate the potential impact of gravity on required injection pressures.

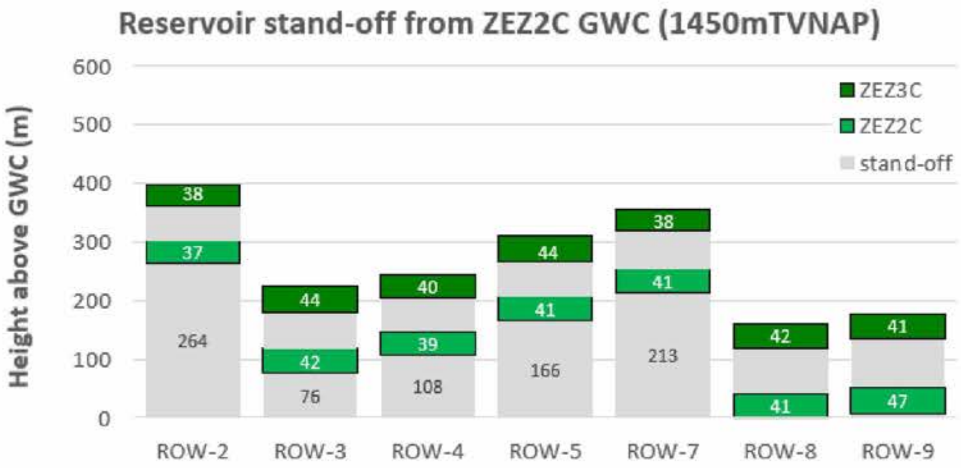

Figure 4-6: Reservoir stand-off from the Gas Water Contact for each well (ZEZ2C GWC at 1450 mTVNAP).

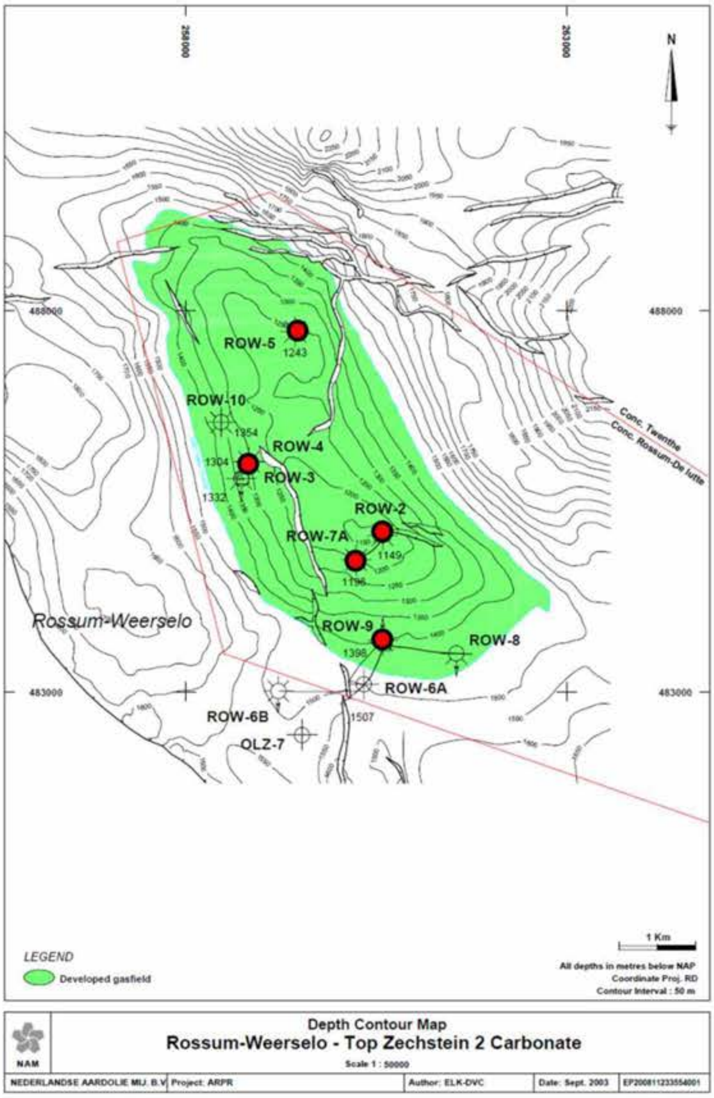

Figure 4-7: Top reservoir map (ZEZ2C), highlighting the water disposal wells in red.

Table 4-1: Injected volume of water compared to modelled and permitted capacity (as of 31/12/2022)

Location	Well	Injected volume mln m³	Modelled capacity[1] mln m³	Degree of filling	Permitted capacity[2] (per location) mln m³	Capacity used (per location)
ROW-2	ROW-2	2.626	13.2	20%	19.1	21%
	ROW-7	1.365	2.1	65%		
ROW-3	ROW-3	0.044	2.2	2%	7.8	33%
	ROW-4	2.495	4	62%		
ROW-5	ROW-5	1.414	13.5	10%	6.59	22%
ROW-6	ROW-9	0.471	1.8	26%	1.61	29%

[1] Assuming an initial gas saturation of 80%

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

4.3 Injection rates and pressures

In section 4.1 the calculation is given for $THPi_{max}$ to ensure integrity of the confining layers. A safety margin of 10% 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. As an additional barrier, a Pressure Safety Valve was installed.

Figure 4-8 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.

Figure 4-8 shows a number of wells to be sub-hydrostatic injectors: as a result of a low reservoir pressure and high injectivity, the bottomhole flowing pressure is so low that it cannot sustain a full water column up to surface (ROW-2, ROW-5, ROW-7 and ROW-9), see also Appendix B of Reference [16]. 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). Only well ROW-3 and ROW-4 are relatively tight injectors and require elevated tubinghead pressures to squeeze the water into the reservoir.

Note that occasionally, Figure 4-8 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 pressure.

Table 4-2: Maximum surface injection pressure, Reference [1].

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%

Figure 4-8: Daily flowing tubing head pressure with THP limit (bottom), daily injection rates (middle), and cross-plot of THP versus injection rate for all ROW wells (top), 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 [12], 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 4-9.

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 [1]. 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 [8].

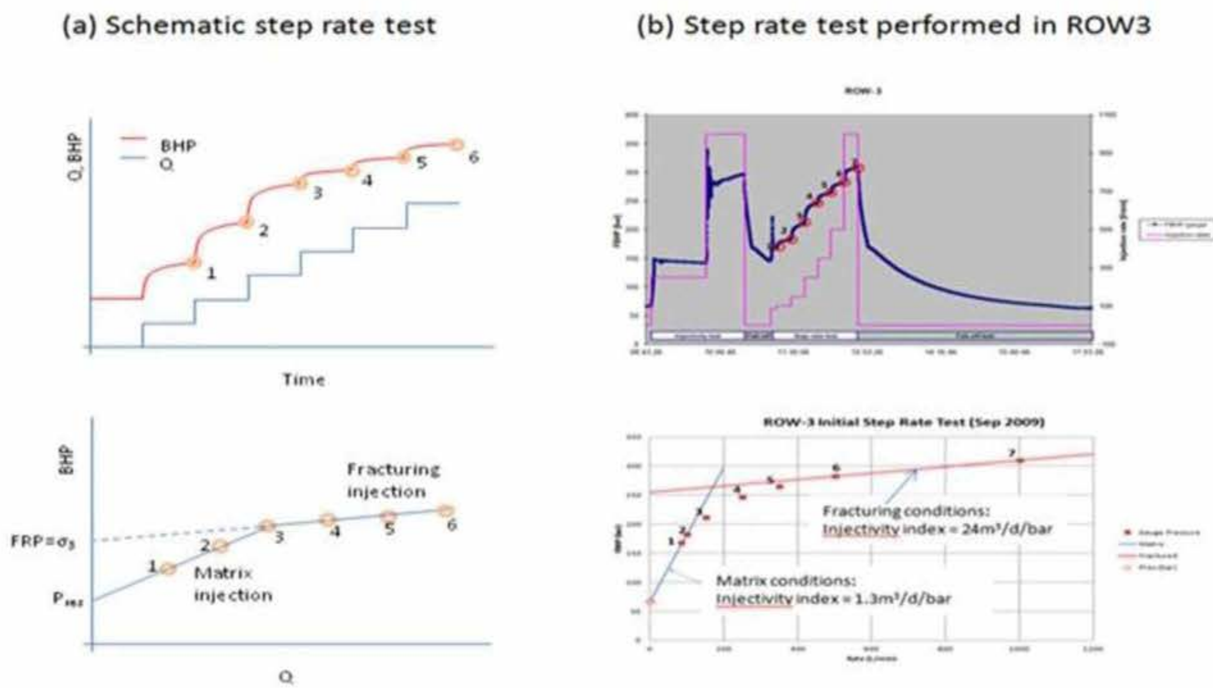

Figure 4-9: Illustration of a step-rate test in a matrix type reservoir. Data from well ROW-3 which connects to the Carboniferous (DC) sandstone reservoir.

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

Year	Well / Parameter	ROW-2	ROW-3	ROW-4	ROW-5	ROW-7	ROW-9
2009	**Injectivity, m3/d/bar**	733	1 (matrix) 26 (fractured)	-	-	-	-
	Pressure stability	Poor	Very good	-	-	-	-
	Duration per step	15 min	15 min	15 min	15 min	15 min	-
	Remark	BHP almost independent of inj. rate	Formation breakdown	No data, BHP independent of injection rate	High injectivity, no fluid at BHP gauge depth	Very good injectivity, no fluid at BHP gauge	No data
2011	**Injectivity, m3/d/bar**	324	-	6	-	-	12
	Pressure stability	Very poor	-	Very poor		-	Good
	Duration per step	1 day	-	1 day		-	1 day
	Remark		No sustained injection		High injectivity, no fluid at BHP gauge depth	Unable to remove tree cap	
2012	**Injectivity, m3/d/bar**	79	-	7	-	55	9
	Pressure stability	Very poor	-	Very poor		Good	Good

	Duration per step	5-7 days	-	5 days		5 days	5 days
	Remark	Test extended until Jan 2013	No sustained injection	Acid stim. in May prior SRT	High injectivity, no fluid at BHP gauge depth		
2013	**Injectivity, m3/d/bar**		-	6	-	192	12
	Pressure stability		-	Very poor		Very good	Good
	Duration per step		-	5-7 days		14 days	7-10 days
	Remark		Well is shut-in long term	Acid stim. in June prior SRT	High injectivity, no fluid at BHP gauge depth	Acid stimulated in June	Acid stimulated in June

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 [17]. 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 [18]. Note that other than an actual casing leak, commingled injection also exposes the casing section in between the two injection reservoirs to a potential flow path, see section 5.4. If only one of the aforementioned 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). Recently this was supplemented with pulsed neutron logging (PNLs). The monitoring results for each survey are discussed in the next sections.

Note that ROW-3 is completed on the deeper DC sands, and for that reason carries no risk of halite dissolution. Injection into this well has been minimal and it has been suspended since 2016. This well is therefore not included in the surveys discussed in this section.

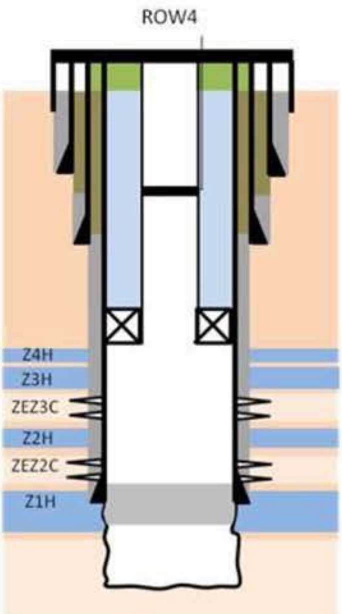

Figure 5-1: Typical water injector well schematic showing Halite sections behind production casing (ZnH represents salt layers, ZEZnC represents carbonate layers where the water is injected into. Between the salt and carbonate layers is a thin Anhydrite layer)

5.2 Temperature logging

Temperature logging was 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 straight line represents the undisturbed geothermal gradient that is generally applied for the underground in The Netherlands:

$$\text{undisturbed temperature} = 10.1°C + 0.031°C/mTV$$

In well ROW-7 the actual injection points within the Zechstein Carbonate layers can be differentiated, which appear to line up very well with the PLT that was run during the gas production phase.

Unambiguous verification of injection solely into the Carbonate formations 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.6) 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) it is relatively difficult to differentiate injection into Carbonate layers versus that into the ZEZ2H, which is located in between the ZEZ2C and ZEZ3C 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.

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.

The temperature logs showed that water is injected into the perforated Carbonate formations, and did not show any indication that injected water has come into contact with Halite layers. However, temperature logs can only be conclusive when there is significant water flow (and associated temperature effects). 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.

Given the limited ability to conclusively resolve the actual injection layers from temperature logging, dedicated temperature surveys were discontinued after 2013.

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-3	11-Dec-12	600 (1d)	1	yes	yes	Injection point aligns with perforations into highest porosity streak
ROW-4	12-Dec-12	1,200 (20d)	0.9	yes	yes	Injection point aligns with gas production PLT run in June 1991
ROW-5	30-Nov-12	1,000 (18d)	1	yes	yes	Temperature survey not run passed separation packer down to ZEZ2C. Injection point aligned with bottom perforated interval.
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	

5.3 Cement bond logging and casing condition surveys

5.3.1 Additional surveillance following ROW-2

Triggered by the observed casing shear in ROW-2 during the workover in early 2021 (section 6.1) additional surveillance was done on the other injection wells (i.e. in addition to the scope of the WMP version 2018 which was prevalent at the time). Results and conclusions of these additional non-routine surveys in ROW-4/5/7 are summarized below.

ROW-4

- Casing caliper below the completion tailpipe. Results indicate the casing to be in “moderate” condition, with maximum pitting corrosion of 33.9%. For comparison, Table 6-2 below presents a complete history of casing condition logging results.
- Production casing cementation evaluation below the completion tailpipe. The results of the 2021 survey are very similar to the earlier 2013 survey. A more detailed discussion is presented below in Section 5.3.2.
- Metal-loss survey (TGT-Pulse) of the tubing above the packer and the production casing from the perforation zone to surface. The results indicate following: (1) maximum metal loss in the tubing of 12%; (2) the production casing above the packer has 12% metal loss, without indications of casing shear; (3) the production casing below the tailpipe has maximum 10% metal loss above the perf zone, and 18% in the blank section between the two perf intervals.
- Pulsed Neutron Log, of which results are discussed in detail in Section 5.4 below.

ROW-5

- Casing caliper below the completion tailpipe. Results indicate the casing to be in “good to moderate” condition, with maximum pitting corrosion of 18.1%. For comparison, Table 6-2 below presents a complete history of casing condition logging results.
- Production casing cementation evaluation below the completion tailpipe. Results are discussed below in Section 5.3.2.
- Metal-loss survey (TGT-Pulse) of the tubing above the packer and the production casing from the perforation zone to surface. The results indicate following: (1) maximum metal loss in the tubing of 10%; (2) the production casing above the packer has 15% metal loss, without indications of casing shear; (3) the production casing below the tailpipe has maximum 15% metal loss above the perf zone, and 7% in the blank section between the two perf intervals.
- Pulsed Neutron Log, of which results are discussed in detail in Section 5.4 below.

ROW-7

- Metal-loss survey (TGT-Pulse) of the tubing above the packer and the production casing from the perforation zone to surface. The results indicate following: (1) maximum metal loss in the tubing of 15%; (2) the production casing above the packer has 17% metal loss, without indications of casing shear; (3) the production casing below the tailpipe has maximum 11% metal loss above the perf zone, and 11% in the blank section between the two perf intervals.
- Archer Space-Panorama survey (ultrasonic imaging tool) of the casing below the completion tailpipe. Overall good casing condition, with some light casing wear observed on the low side. No indication of casing deformation. Some pitting observed (up to 64%) in casing below perf zones.
- Pulsed Neutron Log, of which results are discussed in detail in Section 5.4 below.
- EV Camera and X-Y Caliper of casing below the completion tailpipe. Unfortunately, these surveys did not yield any usable data.

Caliper surveys of the casing section below the production packer and tubing tailpipe have been recorded since 2013 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. 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.

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.

The condition of the production casing below the packer has been assessed at various time intervals (in line with the revision of the Waterinjectie Management Plan in force at the time). Multi-finger calipers have been recorded in all wells except ROW-7. In the latter well, multi-finger tools cannot provide meaningful data due to the large ID difference between casing and tubing. In ROW-7 casing condition is monitored by EMIT survey (2015) and Multi-Tube Integrity (MTI, tradename TGT-Pulse, i.e. metal-loss) surveys (2020 and later).

Section 6.3 presents an overview of the results of tubing and casing condition surveys since 2013.

5.3.2 ROW-4 and ROW-5 CBL results

Cement Bond Logs in the ROW wells were done in 2013, and were previously presented and discussed, see e.g. references [2], [3] and [4]. Following the ROW-2 casing failure repeat CBLs were acquired on wells ROW-4 and ROW-5 in 2021. No reliable log could be obtained from ROW-5 due to the low pressure in the wellbore during shut-in. Another attempt was done whilst injecting (to increase the pressure) but this caused high "noise" levels in CBL signal. Given the relatively higher pressure in well ROW-4 (section 4.2) a successful CBL log was acquired there. The interpretation of this CBL by Expro Well Services was shared with SodM on 24 December 2021. The interpretation showed presence of reasonable to good quality cement, with some small intervals of poor cement to a depth of 1375mAHDFE. This was in line with the conclusions from the first CBL on the well which was taken in 2013 (no CBL had been taken when ROW-4 was drilled in 1971).

However, when the 2013 and 2021 CBLs are plotted directly next to one another, a change can be seen. Figure 5-2 shows how both measurements are virtually identical across the whole interval. But at the base of the Zechstein 2 halite, at a depth around 1365 m AHDFE, a clear change can be seen between both measurements: the amplitude of the measurement in 2013 stays low, whilst the 2021 data increases beyond 60 mV. The change is confirmed in the VDL data, which rules out a measurement error in the CBL amplitude data.

Table 5-2 summarizes the conclusions from the CBL and casing condition surveys, and presents the risk level of exposure of the Halite to injected water.

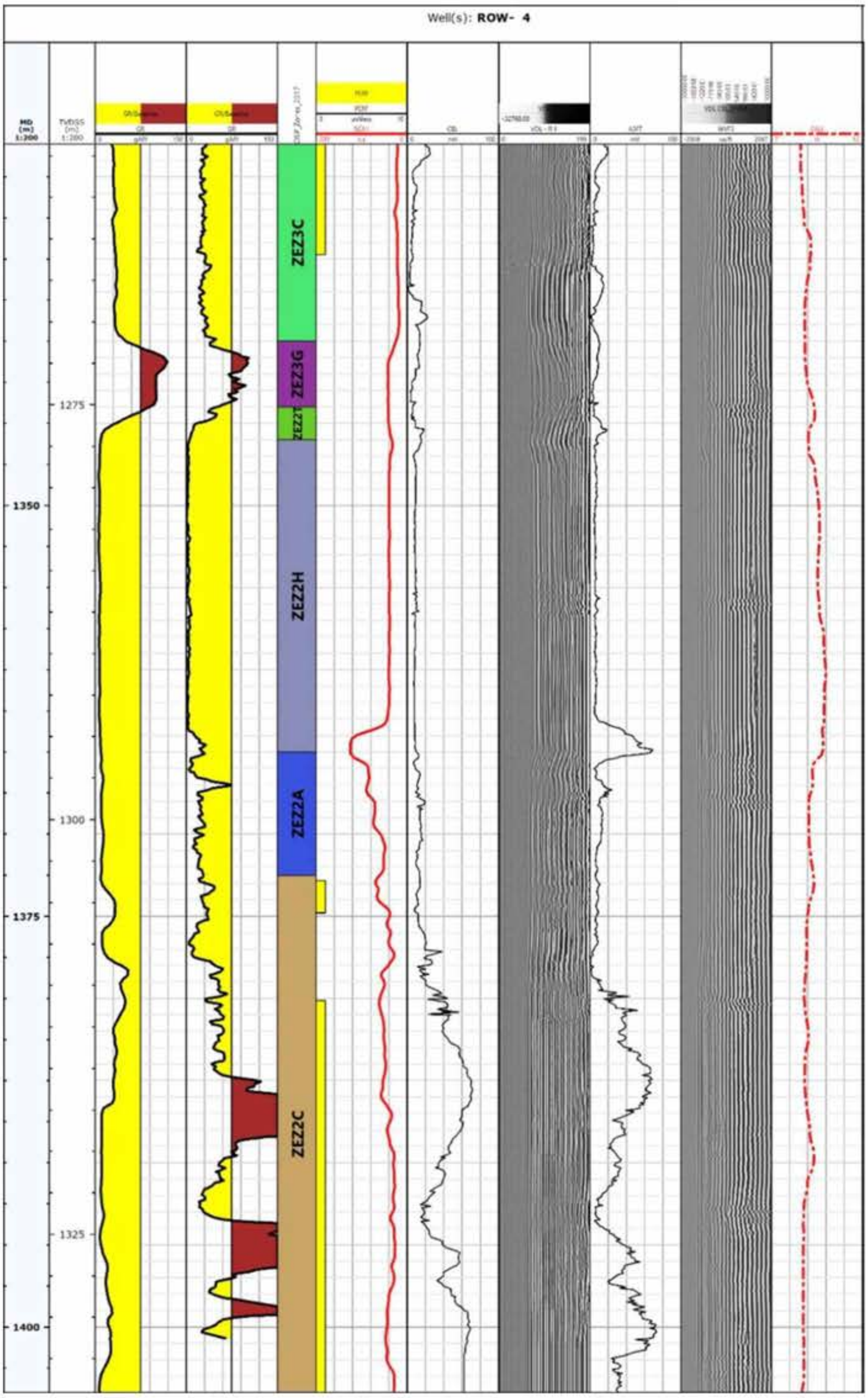

Figure 5-2: CBL measurements from 2013 compared to 2021. Track 1: along hole depth (mAHDFE), 2: true vertical (mTVNAP), 3: Open hole gamma ray 1971, 4: gamma ray 2021, 5: lithology indicator, 6: apparent sigma 2021 (red), perforation interval (yellow), 7: CBL amplitude 2013, 8: VDL 2013, 9: CBL amplitude 2021, 10: VDL 2021, 11: open hole caliper

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

Well	High level conclusions	cement*	casing*	Way forward	Risk level
ROW-2	Good cement bond; no casing corrosion detected			No follow-up, well has been subsurface-abandoned at top Zechstein level	Low
ROW-4	Mainly good cement bond. Indication of deteriorating cement bond at base of ZEZ2H. Pitting and metal loss indicates casing over the Zechstein formations to be in good condition			Well is currently suspended. No follow-up, well will not be used for any future injection.	Low (no further injection)
ROW-5	Good to fair cement bond. ZEZ3C-ZEZ3H transition interval cement bond masked by fast formation. Poor cement bond at ZEZ2C, but good bond over ZEZ2H. Pitting and metal loss indicates casing the Zechstein formations to be in good condition			Well is currently suspended. Continue with monitoring of casing condition if/when injection is resumed.	Low
ROW-7	Legacy/historic CBL data indicate good cement bond over relevant intervals. MTI results indicate <5% metal loss in the casing section below the packer and above the perforations , including the section opposite the tubing tailpipe			Well is currently suspended. Continue with monitoring of casing condition if/when injection is resumed.	Low
ROW-9	Good cement bond, no casing corrosion but minor corrosion in tubing.			No follow-up. Well is suspended, not in use as water injector.	Low

*Cement / casing risk rating over halite intervals, colour coding: low (green) -medium (amber) – high (red).

5.4 Pulsed Neutron Logging

As part of the investigation around ROW-2, NAM executed additional surveillance in 2021 on the active (Rossum-Weerselo) water injection wells, which included Pulsed Neutron Logging. This concerned an experimental application of the PNL technology, which is normally applied to monitor changes in gas saturation behind casing. In well ROW-4 an anomaly was found at the base of the halite layer between the Zechstein 2 and Zechstein 3 carbonate injection reservoirs, which could indicate brine behind the casing. A repeat survey in January 2022 confirmed this measurement. In July 2022 NAM submitted an investigation into the ROW-4 measurements to SodM, reference [5]. An extract from the main conclusions is given below.

Salt water was observed in well ROW-4, behind the casing where normally a hard halite layer is present (ZEZ2H). This halite layer is located between the two injection reservoirs. No excursions were detected at the halite layer above the injection reservoirs (ZEZ3H). Consequently there has not been any loss-of-containment, and there are no consequences for people or environment.

The ROW-4 situation concerns a local washout effect of limited lateral depth, between 0.15 and 3m, a laterally extensive cavity – i.e. pancake-shaped – is physically not possible, see section 5.1 of Reference [5]. Two scenarios were identified which could have resulted in dissolution of halite behind casing:

- U-tubing
- Halite dissolution by cross-flow between two injection reservoirs

In both scenarios the process starts with the presence of a micro-annulus, which can originate over time by deterioration of the cement bond with the casing (e.g. by thermal cycles) or by deterioration of the cement itself. When the non-salt-saturated injection water starts to flow through such a micro-annulus, if it gets exposed to the halite layer it can start to leach out the salt and increase the size of the flow-path (cylindrical shaped growth).

Both scenarios can explain the observations from the logging. From calculations of the physical flow mechanism a range was established for the flowrate behind casing and the associated diameters of the flowpath. A flowrate of 0.3 liter per day through a micro-annulus can already explain the measurements. Because it is impossible to pinpoint the actual dimensions of the cavity with measurements, these calculations are indicative at best. Given these low flow velocities, a repeat PNL survey under flowing conditions is not expected to yield any conclusive results.

For both identified scenarios, the risk (for now and in the future) is mitigated by the following measures:

- Mitigate risk of further increase in cavity size at ROW-4 by stopping injection into this well.
- In the 2022 WMP update (Ref. 17) an addition was included to the annual inspection program: Measurement of the halite caprock. Time-lapse PNL make it possible to detect changes in the formation behind casing at the active water injection wells.

As per the updated WMP, repeat PNL surveys were executed for ROW-4, ROW-5 and ROW-7 in September 2023. No changes have been observed in the 2023 operation, with exception of the fluid inside the cavity behind casing in ROW-4. This is interpreted as a change from salt water to fresh water, attributed to the fresh water flush that is done as part of the logging procedure to ensure access to the logging target interval, reference [19]. The Halite rocks in ROW-4 , ROW-5 and ROW-7 show to be unchanged from the previous acquisition in 2022.

6 Well integrity surveillance and management

6.1 ROW-2

6.1.1 Overview

In well ROW-2 a casing shear was observed just above the Zechstein 2 Carbonate injection reservoir during a work-over in 2021. This could not be cost-effectively repaired and the well was abandoned with a cement plug.

NAM submitted a root cause analysis to SodM in May 2021, reference [20]. At the request of SodM, NAM conducted further investigation: Part 1 was issued in December 2021, reference [21], and Part 2 in March 2022, reference [16]. SodM concluded in May 2022 that the ROW-2 event was sufficiently investigated, reference [22]. There has been no damage to people or the environment. The ROW-7 well, which had been precautionary closed in due to its proximity to ROW-2, is available again for injection.

Reference [16] concludes that the casing shear cannot be conclusively attributed to a single cause. It is likely that a combination of various effects from gas production and water injection have resulted in the casing shear.

Consequently, the risk of a similar event happening at other injection wells cannot be fully excluded. However, potential consequences can be detected timely with an adequate surveillance program, and can be mitigated and controlled. Hereto the Waterinjectie Management Plan has been updated. The casing shear event is interpreted to be related to a pressure event that was observed on the A-annulus of ROW-2 in 2017. The pressure thresholds for NAMs procedures at the time did not reveal a root cause. After the observed casing shear in 2021 NAM has adjusted its surveillance and monitoring program as captured in an update of the WMP. Furthermore NAM has executed additional surveillance at wells ROW-4, ROW-5 and ROW-7, which included TGT-Pulse metal-loss logging, downhole camera surveillance and Archer Space-Panorama ultrasonic imaging. This did not lead to any new conclusions, see also Section 5.3. The surveillance efforts have demonstrated that no casing shear similar to ROW-2 has occurred in the other injection wells. Also for the nearby injector ROW-7 well integrity was demonstrated, both the tubing and casing are intact.

An extract from the main conclusions of reference [16] is given in the following sections.

6.1.2 ROW-2 casing shear bow-tie analysis

The ROW-2 casing shear event was analysed using a Bow-Tie approach (Figure 6-1). A range of plausible mechanisms for casing shear were identified and further investigated. These 6 “threats” constitute the left side of the Bow-Tie and have been further investigated through modelling and research.

The right side of the Bow-Tie describes the barriers that were in place when the event occurred and which served to prevent damage to the environment or people. These barriers consisted of casing and tubing, both including surveillance and monitoring, and most importantly the presence of a thick caprock of Zechstein layers.

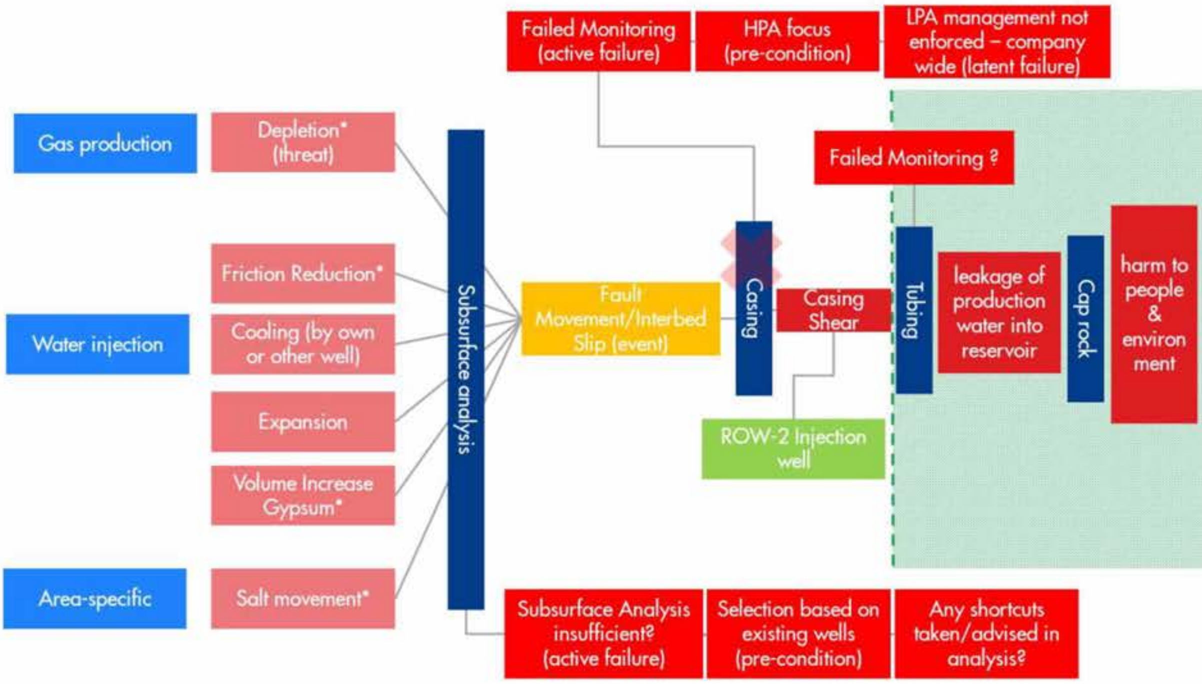

Figure 6-1: Bow-Tie for ROW-2 casing shear.

6.1.3 Left hand side of the Bow-Tie

Although cooling (the injection water is colder than the reservoir) appears to be a dominant threat for the fault/bedding slip plane to move, it cannot be ruled out that a combination of threats, eventually, was responsible for a critical stressed plane to induce or trigger sliding/slipping. It is plausible that wetting of a fault/bedding slip plane in combination with cooling provided the necessary conditions for the casing shear, possibly supported by remnant shear stresses from the depletion phase. The other mechanisms have also been investigated but either appear to have negligible effect on the subsurface stress conditions or modelled displacements (salt movement). Finally, anhydrite to gypsum conversion is unlikely to occur.

6.1.4 Right hand side of the Bow-Tie

One of the outcomes of the full investigation into ROW-2 is the failure within NAM to come to an integrated and timely analysis of anomalous casing pressure signals, inadequate internal communication, and subsequent reporting to SodM. This so-called 'active failure' has been described in the Bow-Tie and is preceded by what is called a 'pre-condition' and a 'latent failure', shown by the red boxes. The latent failure can be described as the company wide lack of attention given to low pressures (because there is no history of incidents causing harm due to low pressures) and the focus on preventing high pressure incidents (with known incidents in the company and industry)

Furthermore, the Bow-Tie shows completion items (casing and tubing) as barriers (blue, vertical bars). These barriers prevent fluid access into undesired areas, when intact or deformed (but still intact). Barrier integrity can be breached when rocks slide over sufficient distance. Completion items will likely shear off, either fully or partly, depending on the dimensions of the tubulars.

Finally, the far-right side of the Bow-Tie contains the cap rock as a geological barrier. This barrier is 50 meters thick and consists of a sequence of carbonate, anhydrite, and halite layers. These layers provide an extremely tight seal above the injection zones. Around the wellbore annular flow is protected by cement and across halite layers additional pack off around the casing prevents injection fluid to reach areas above the cap rock.

6.1.5 Remedial actions to date

An extension of surveillance methods with focus on low pressure annulus measurements has been proposed and implemented. These instructions are rolled out to operators in the field and have also been recorded in the updated WMP. With the closer surveillance of the liquid level in the A-annulus, a casing shear event as happened in ROW-2 cannot be prevented but does allow for timely measures to be taken to isolate the well and keep it safe.

6.1.6 Conclusions and recommendations for other Twente water injectors

The Bow-Tie used for ROW-2 can also be applied to the other Twente water injectors. Three conditions are key for the water injectors to operate safely:

1) Adequate subsurface analysis; identify nearby faults on seismic
2) Updated monitoring & surveillance program for casing, tubing and packers is in place, in case condition 1 cannot be met.
3) Cap rock above injection zone is thick and provides a reliable seal away from the well and has a proven seal around the well either by cement and/or formation pack-off by halite or shales.

If above conditions apply, the risk to people and environment are negligible and meet the ALARP principles accepted in the industry.

Table 6-1 compares the 6 subsurface threats on the left-hand side of the ROW-2 bowtie for the other Twente water injectors. Furthermore, the presence for nearby faults and/or a slip plane have been considered. This overview provides a relative ranking of the subsurface conditions and associated suitability for water injection (condition 1 above). It shows that all other wells score better than ROW-2, indicating a lower risk of a similar casing shear event for all other wells, including ROW-7. Conditions 2 and 3 equally apply for all water injectors in Twente, offering sufficient guarantees for safe water injection for now and in the future.

Table 6-1: Relative comparison of subsurface threats for the Rossum-Weerselo water injectors.

Well	Fault	Slip Plane	Depletion	Friction Reduction by water	Cooling by water	Expansion	Volume increase	Salt Movement	Relative rating for water injection
ROW-2	-	-	+	-	-	+	++	++	2+
ROW-4	+/-	+	+	+	+	+	++	++	9+
ROW-5	+	+	+	+	+	+	++	++	10+
ROW-7	+	+	+	+	+	+	++	++	10+

+ = likely no impact
++ = no impact
+/- = might have impact
- = impact likely
-- = high impact

6.2 Hold-Up Depth Monitoring

Monitoring of the Hold-Up Depth (HUD) in the wells is done to monitor the possible accumulation of solids at the bottom of the wells. 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 6-2 presents the recorded HUD measurements since the wells were completed on their present reservoir zone, before as wel as after they were converted to water injectors. Since becoming water injectors, the wells only show minor variations in HUD. Except for the Notes provided in the caption of Figure 6-2, these minor variations are 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.

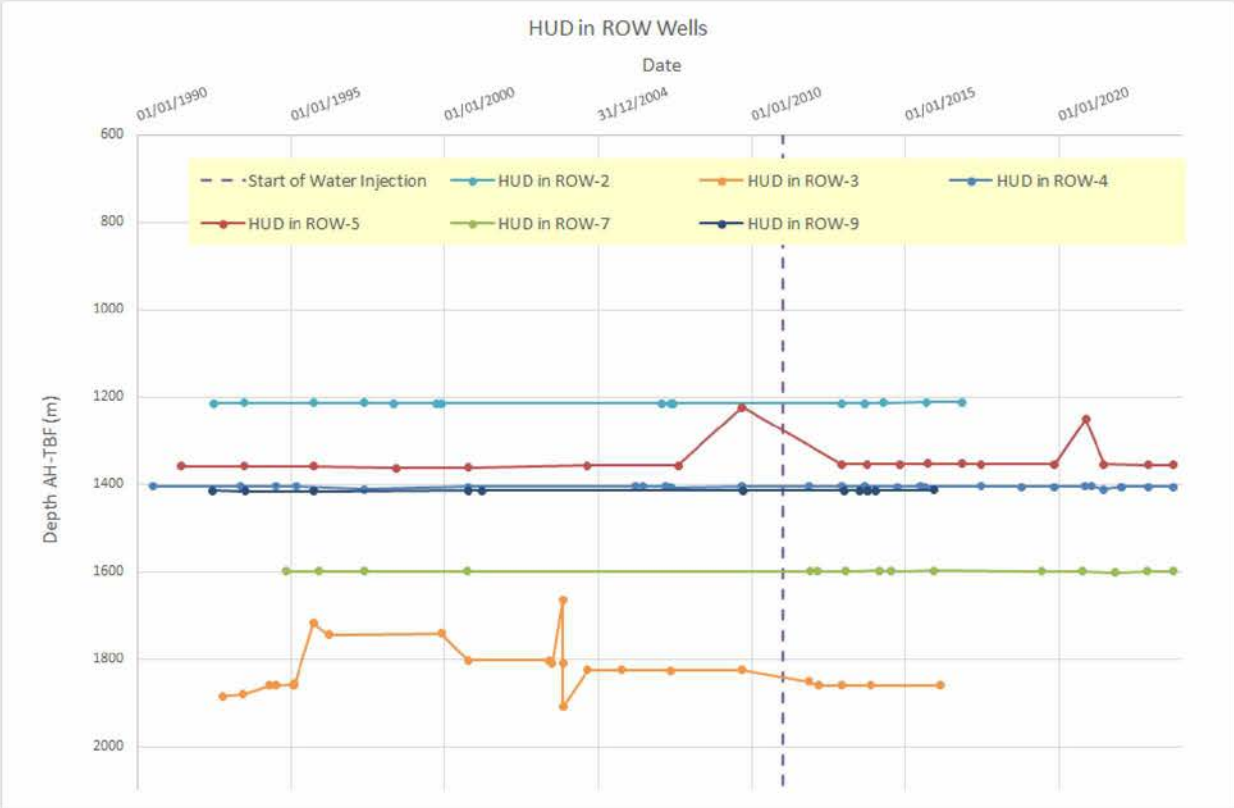

Figure 6-2: Measured well Hold-Up Depths in the ROW wells, before and after the start of water injection.
Note 1: ROW-2 data presented only for the period before onset of tubing deformation (see also Refs [20], [16])
Note 2: ROW-5 HUD in 2009 and 2020 was affected by the slickline tool not passing the separation packer in this well
Note 3: No HUD data from wells ROW-3 and ROW-9 since their suspension in 2015/2016

6.3 Tubing and Casing condition 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 are regularly carried out in all ROW 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 6-3. The red dashed line indicates a notional pitting degree limit of 60%, which was used in the past as a trigger to consider change-out of the tubing, References [23] and [24]. Figure 6-3 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 notional pitting degree limit of 60%, except for ROW-7. From 2015 onwards the caliper survey in ROW-7 indicates pitting in excess of 45% recorded at roughly the same depth of 1162-1165mAHTBF. Some of these measurements even indicate pitting in excess of 60%. Uniaxial strength calculations however indicate that the tubing in ROW-7 can stand up to 80% pitting before the strength reduction would become critical for use as water injector under the current conditions of pressure and temperature. 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 when water injection is resumed.

Table 6-2 summarizes the actual integrity state of the casing for each well with respect to the observations from the various surveys. Wells that are no longer used for water disposal are not part of the surveillance scope.

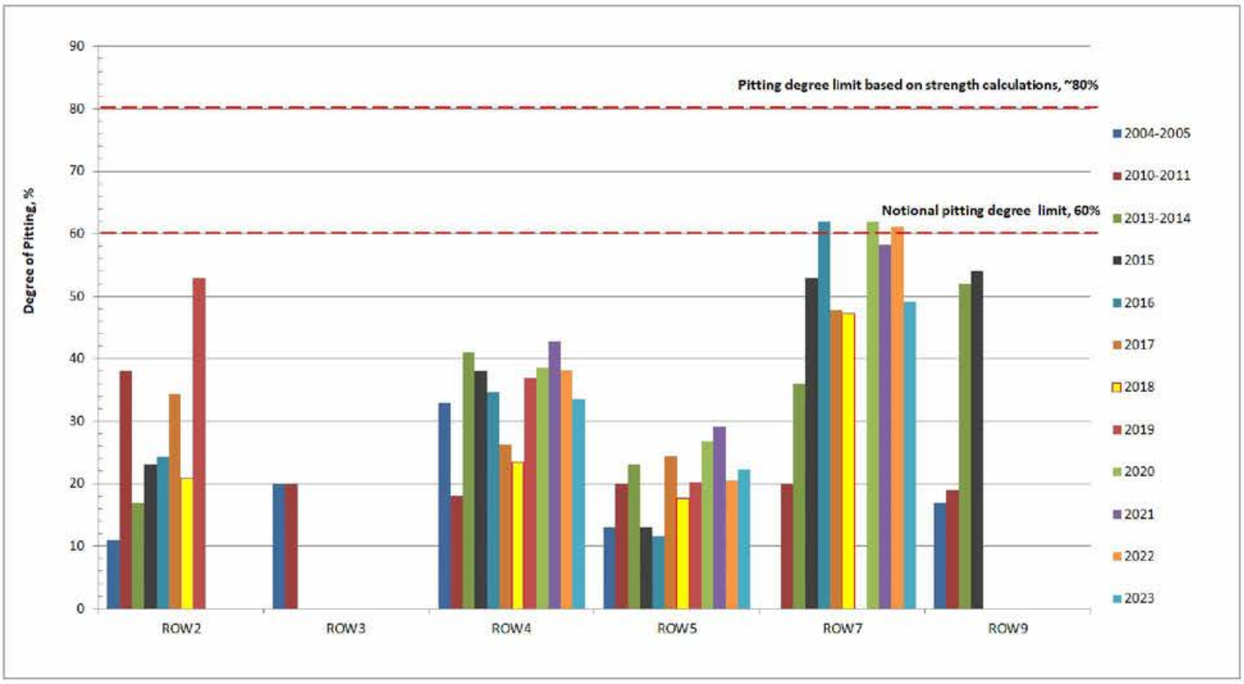

Figure 6-3: Maximum wall penetration for the ROW wells derived from caliper surveys since start of injection
Note 1: ROW-3 and ROW-9 have been suspended since 2015/2016 therefore no recent tubing caliper surveys
Note 2: Tubing caliper in ROW-7 could not be executed in 2019 due to operational issues.

Table 6-2: Overview of casing conditions from survey data

	Time of survey & Surveillance Tool	ROW-2	ROW-3	ROW-4	ROW-5	ROW-7	ROW-9
Production casing size, inch		7	9-5/8 and 4-1/2	7		9-5/8	7-5/8
Production casing / lner install date		1955	1968	1971	1972	1976	1978
Start of water injection		2011	2011	2010	2010	2011	2011
Years as gas producer		56	43	39	38	35	33
Packer top depth mAHDFE		1147	1656	1211	1144	1210	1302
Wireline Entry Guide bottom depth mAHDFE		1156	1666	1221	1153	1220	1312
Top of perforations / open hole mAHDFE		1179	1808	1373	1207	1283	1359
Max penetration casing below packer @ depth	2013/2014		ROW-3 not logged as no risk of halite dissolution				
Max metal loss casing below packer @ depth	PMIT	8% @ 1165m		3.1% @ 1227m	13% @ 1180m	10.3% @ 1520m	13% @ 1340m
Casing survey interval mDFE	EMIT	1156-1175m		1224-1402m	1153-1359m	1230-1600m	1312-1414m
Max penetration casing below packer @ depth	2015			34.9% @ 1326m	47% @ 1286m		<20%
Max metal loss casing below packer @ depth	MFCT / PMIT	7.6% @ 1165m		10.4% @ 1366m	12% @ 1180m	9.7% @ 1319m	18% @ 1340m
Casing survey interval mDFE	EMIT			1221-1402m	1153-1344m	1221-1597m	1313-1414m
Max penetration casing below packer @ depth	2016	23.8% @ 1156m		29.2% @ 1215m	21% @ 1167m	Casing not logged	ROW-9 Suspended
Max metal loss casing below packer @ depth	MFCT	8.60%		1.3% @ 1215m	12.1% @ 1168m		
Casing survey interval mDFE		1156 - 1174m		1215-1295m	1153-1268m		
Max penetration casing below packer @ depth	Q4-2020	Casing not logged		25.8% @ 1215m	Casing not logged		
Max metal loss casing below packer @ depth	MTI			8.7% @ 1215m		9% @ 1275m	
Casing survey interval mDFE	MFCT			1215-1314m		1191-1590m	
Max penetration casing below packer @ depth	2021	ROW-2 Subsurface-abandoned		33.9% @ 1222m	18.1% @ 1183m		
Max metal loss casing below packer @ depth	MTI			10% @ 1265m 10% @ 1222m	15% @ 1185m 13.2 @ 1183m	11% @ 1275m	
Casing survey interval mDFE	MFCT			1220-1402m	1153-1357m	1198-1592m	
Max penetration casing below packer @ depth	Q3-2023			31.2% @ 1215m	19.5% @ 1176m		
Max metal loss casing below packer @ depth	MTI			9.2% @ 1218m	14% @ 1170m	12% @ 1277m	
Casing survey interval mDFE	MFCT			1221-1375m	1153-1266m	1138-1589m	

6.4 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 (original) 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 N_2 gas.

For all water injection wells in Twente, integrity tests (WITs[8] and SITs[9]) 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, reference [16].

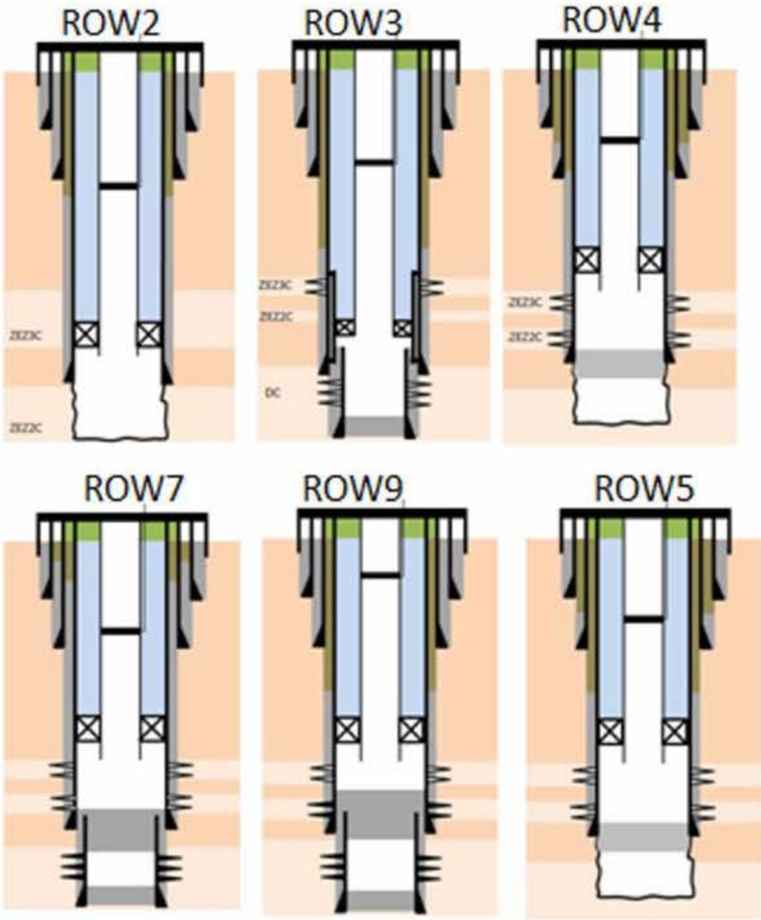

Figure 6-4: Well schematics for the water injection wells

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[8] 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.

[9] 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.

6.5 A-annulus Liquid Level Monitoring

The level of the packer fluid in the A-annuli of the active water injection wells has been monitored on a yearly basis since early 2020. This monitoring activity became a requirement in the WMP version 2022 [1]. Figure 6-5 below presents the results.

The liquid level is determined via the N_2 method, in which the volume of N_2 gas needed to increase the pressure in the annulus by several bar (typically < 5 bar) is measured. The added gas volume and the resulting pressure increase are then used to calculate/estimate the total volume of gas in the A-annulus above the packer fluid. Note that this method is prone to inaccuracies in measuring the pressure increase in the annulus and the corresponding pressure decrease in the N_2 gas bottles that are used as the gas source; small gauge reading errors can have a considerable effect on the outcome of the calculation. The N_2 method is a rough but fit-for-purpose method to get a snapshot of the annulus fluid level. However, the alternative of echo-shots also becomes very inaccurate when the liquid level is located close to surface, as is the case in the measured ROW wells.

Considering the accuracy of the N_2 method, the results presented in Figure 6-5 indicate that since 2020, the liquid levels in the A-annuli have remained close to surface and have not really changed. Note that in this period no liquid top-ups have been done. From these data there is no indication that the integrity of the A-annuli is compromised.

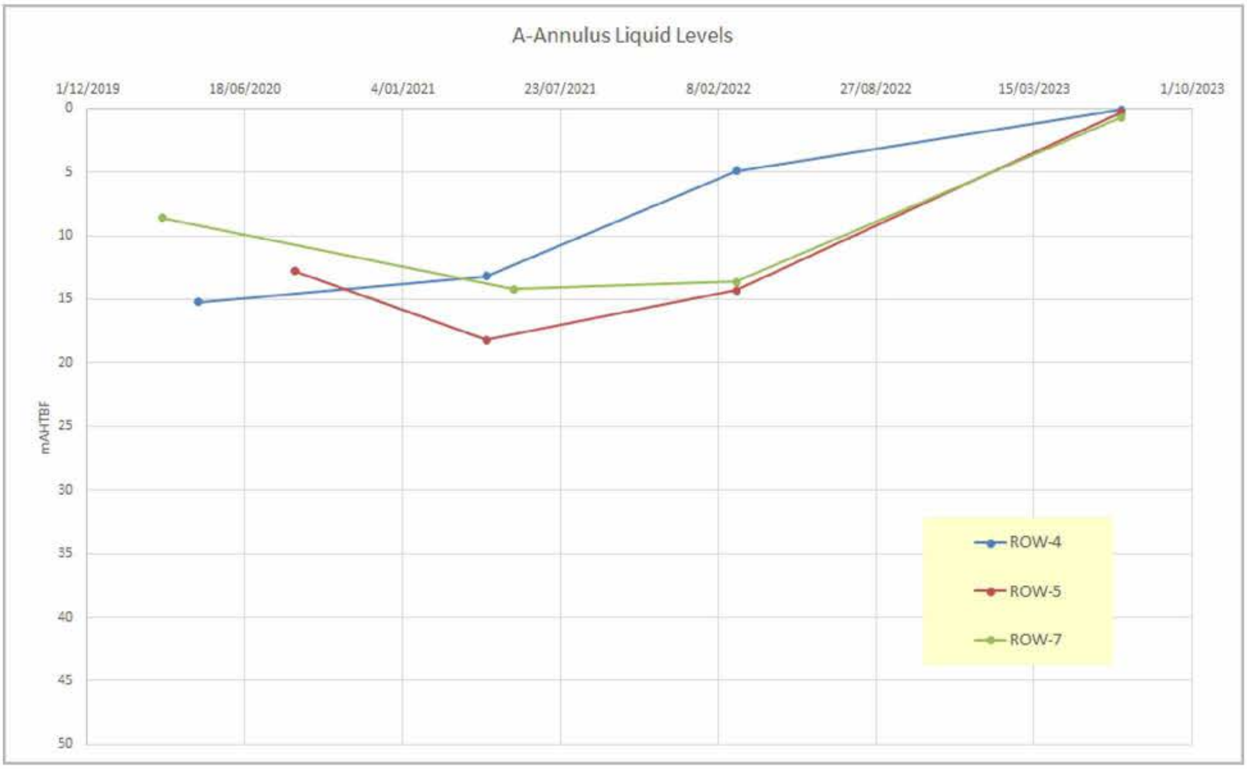


Figure 6-5: A-annulus liquid levels (in mAHTBF) of ROW-4, ROW-5, and ROW-7.

Shortly after the liquid level measurements were done in Jul-2023, the A-annulus pressure in ROW-4 suddenly dropped from 8.1 bar to vacuum. Subsequent A-annulus checks indicated that the liquid level had dropped to about 870 mAHTBF, equalizing with the reservoir pressure. It is suspected that the Side Pocket Mandrel/Dummy Valve and/or the Sliding Side Door, which are located in the upper completion a short distance above the Production Packer, have started leaking resulting in tubing-to-A-annulus communication. ROW-4 was safeguarded by setting a deep plug in the completion tailpipe, i.e., below the suspected tubing accessories, in early Aug-2023. The yearly well integrity logging, which was carried out in Sep-2023 under deviation, did not further clarify a possible cause of the T-A communication. Afterwards ROW-4 was again safeguarded and suspended by a deep plug.

Based on the PNL results recorded for ROW-4 (discussed above in Section 5.4), the well is not considered suitable for water injection in the future. It will remain suspended until well abandonment.

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 2023 periodic evaluation for wells ROW-2, ROW-3, ROW-4, ROW-5, ROW-7 and ROW-9.

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 well monitoring program (as defined in the 2022 WMP update, Reference [1]) 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. By adding PNL logging as a novel surveillance technique, time lapse surveillance can be done for halite dissolution behind the casing. Annual liquid level measurements in the A-annulus were added to the WMP, and the minimum annulus pressure is now further specified in operational procedures.

The conclusions from the technical evaluation carried out are:

- From time-lapse PNL logging it was established that a brine-filled cavity of some 3m height has developed behind casing in well ROW-4 in between the ZEZ2C and the ZEZ3C injection reservoirs. The repeat PNL survey in 2023 showed no change since the 2022 acquisition, which confirms that the dissolution process is related to active water injection (no water was injected in between these two surveys).
- Well ROW-4 is no longer used for water injection and can be abandoned after approval of SodM.
- Time-lapse PNL surveillance on wells ROW-5 and ROW-7 showed no indications of halite dissolution behind casing.
- Well ROW-5 is in a good condition.
- 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.
- With the updated Waterinjectie Management Plan, it is safe to inject in wells ROW-5 and ROW-7.
- Well ROW-2 was abandoned after the observed casing shear in 2021.
- Wells ROW-3 and ROW-9 have been shut in since mid-2015. No new data came available since the last evaluation in 2017 respectively 2020.

Regarding the water injection volumes, the following is concluded:

- The actual total injection rate has been significantly lower than predicted in the FDP, due to lower performance of Schoonebeek Oilfield production wells and restrictions in the water export pipeline.
- Thus far, only 24% of the modeled injected volume has actually been injected into the Rossum-Weerselo Zechstein reservoir, and only 2% was injected into the Rossum-Weerselo Limburg reservoir (ROW-3 well).

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 reservoir pressures as a function of cumulative water injection are in reasonable agreement with the modeled reservoir injection capacity.
  - ROW-2 and ROW-7 are both connected to (and fill up) the same reservoir storage space. By lumping ROW-2 and ROW-7 in a single model, the model match is improved.
  - Well ROW-4 is also connected to the same reservoir storage volume, pressure monitoring shows how well ROW-7 is now aligned with the pressure in ROW-4. However, the reservoir connection is baffled, it took some 1-2 years for the pressure to equilibrate since injection was shut-in. The best match for ROW-4 is achieved with its original model.
  - Well ROW-5 is on a distinctly different pressure trend and shows a reasonable match with the original model.

- All wells except for ROW-3 and ROW-4 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.

- 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-2, ROW-5 and ROW-7 is considered very high, whereas in wells ROW-4 and ROW-9 it is moderate, and in well ROW-3 it is poor.
- Fall-off test analysis suggested a relatively lower fracture density around ROW-9.

On well and tubing integrity, the following is concluded:

- Tubing strength calculations show that all the tubings have sufficient wall thickness (degree of pitting ≤ 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 Annular Surface Pressure (MAASP).
- Pressure data demonstrate full pressure isolation between the tubing, A-annulus and B-annulus.

8 References

[1] NAM, Waterinjectie Management Plan 2022 Twente, EP202205201100, May 2022.

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

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

[4] NAM, Second technical evaluation of Twente water injection wells TUB-7, TUB-10, ROW-7 and ROW-9, EP202012203362, May 2021.

[5] NAM, "ROW-4 onderzoek, EP202207200487," July 2022.

[6] NAM, "Overkoepelende Analyse Ondergrondse Risico's Waterinjectie Twente en Schoonebeek, EP202208202006," NAM, August 2022.

[7] SodM, Brief aan NAM: Beoordeling aanvullend onderzoek ROW-4 en overkoepelende risicoanalyse waterinjectie Twente, 26 september 2022.

[8] SodM, Uw addendum op het evaluatierapport Twente waterinjectie, kenmerk 15137190.

[9] NAM, Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal. EP201310203080, December 2014.

[10] NAM, Subsidence caused by Halite dissolution due to water injection into depleted Carbonate gas reservoirs encased in Halite, 2014 (2016 revisie).

[11] NAM, Jaarrapportage 2022 Waterinjectie Twente, EP202301200033, 20 maart 2023.

[12] NAM, "Schoonebeek Water Disposal: Update of 2006 Water Disposal FDP".

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

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

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

[16] NAM, Eindrapportage onderzoek toedracht scheur put ROW-2, EP202111204310, 31/3/2022.

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

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

[19] Baker Hughes, RPM Pulsed Neutron Data analysis Sigma Monitoring in ROSSUM-WEERSELO Field, Nov/2023.

[20] NAM, Well integrity investigation of well ROW-2, EP202104200659, May 2021.

[21] NAM, Reactie op het onderzoek toedracht scheur put ROW-2 (tussenrapportage), EP202112200643, 23/12/2021.

[22] SodM, Oordeel naar aanleiding voorval ROW-2, 30 mei 2022.

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

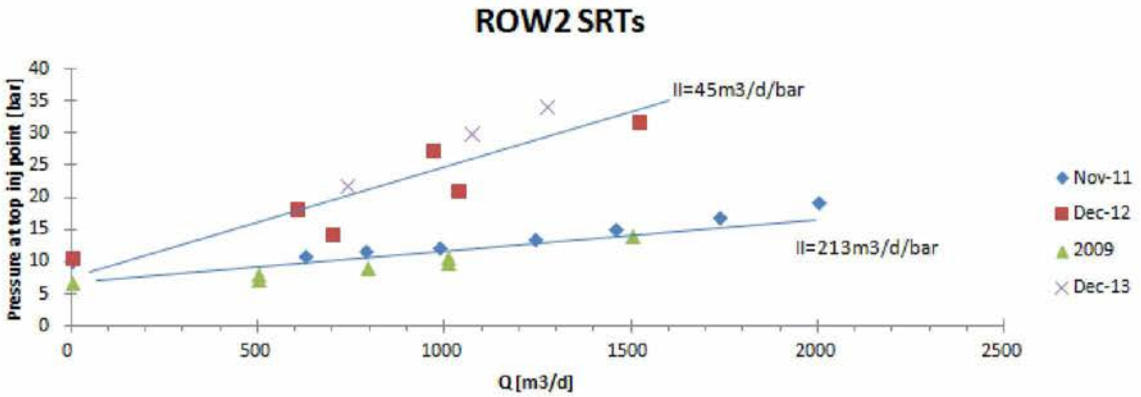
[24] A. Ciufu, Twente water disposal wells - tubing integrity review, March 2016.

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

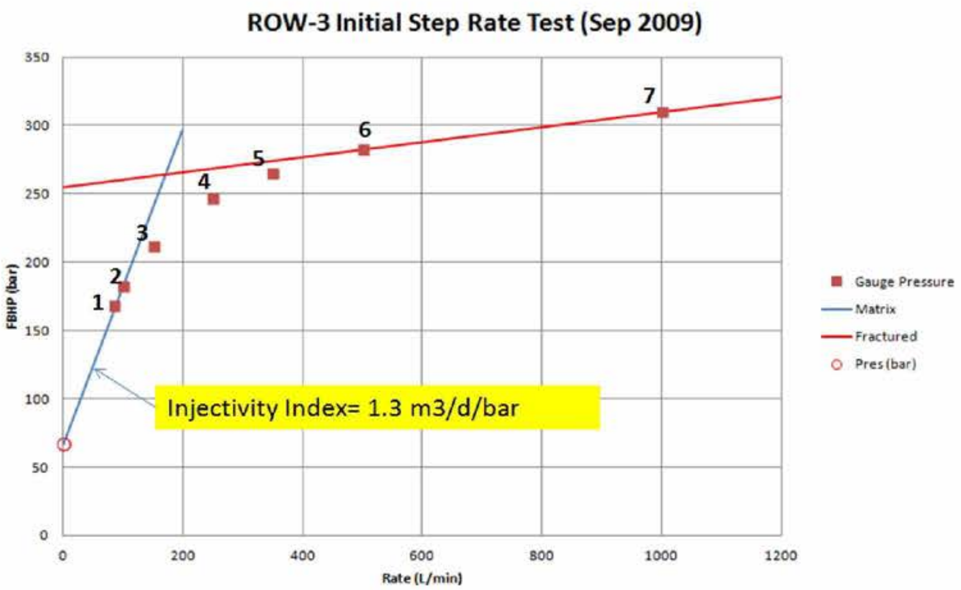
Appendix A Step-rate test results

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

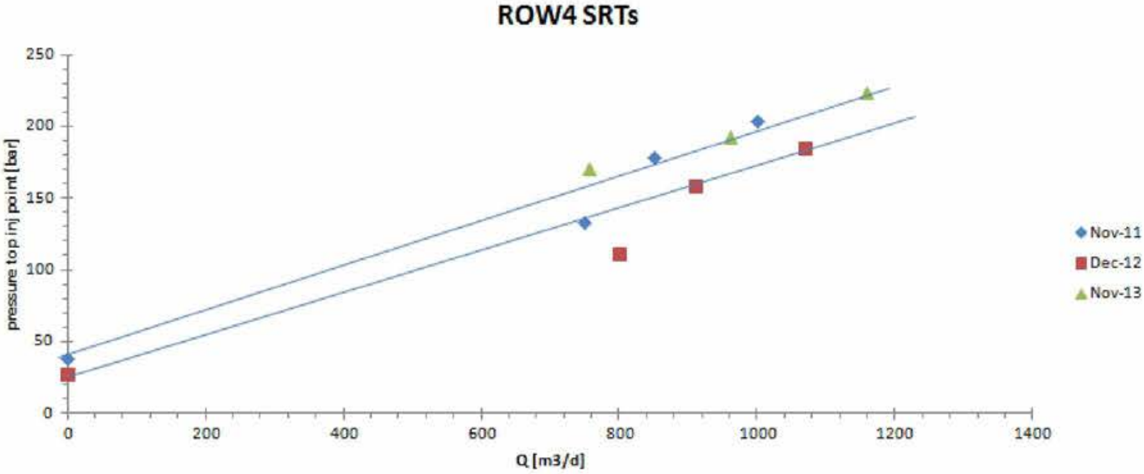
A.1 ROW-2



A.2 ROW-3



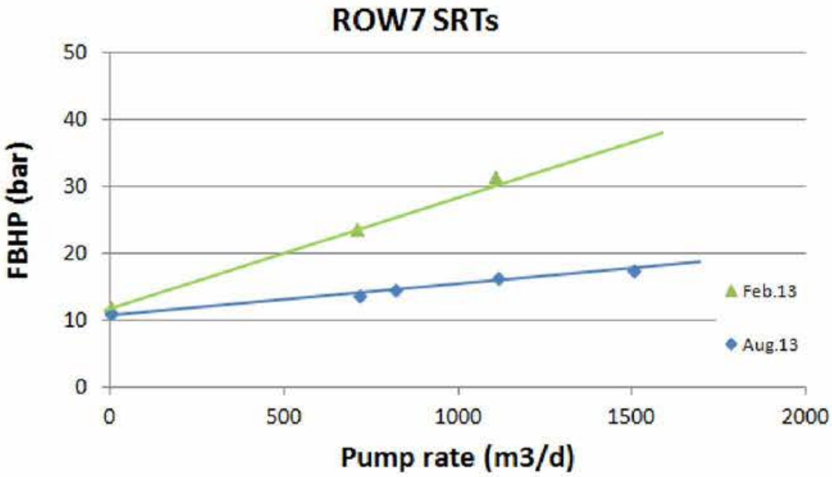
A.3 ROW-4



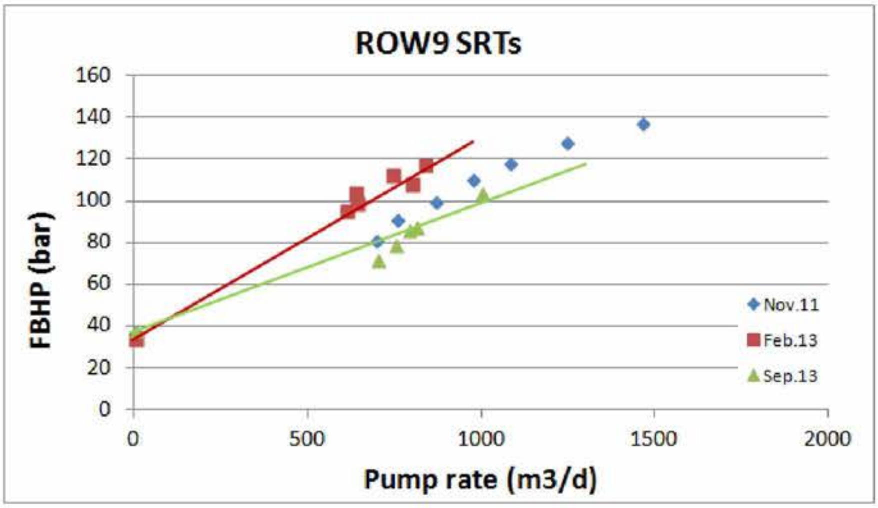
A.4 ROW-5

In ROW5 the injectivity could not be measured as the fluid level leaked off so fast into the reservoir that the fluid column in the wellbore did not even reach the downhole gauge, installed in the tailpipe nipple right above the injection reservoir. This indicates a very good injectivity for this well.

A.5 ROW-7



A.6 ROW-9


ROW9 SRTs
FBHP (bar)
Pump rate (m3/d)
0
20
40
60
80
100
120
140
160
0
500
1000
1500
2000
Nov.11
Feb.13
Sep.13

Appendix B Temperature logging results

B.1 ROW-2

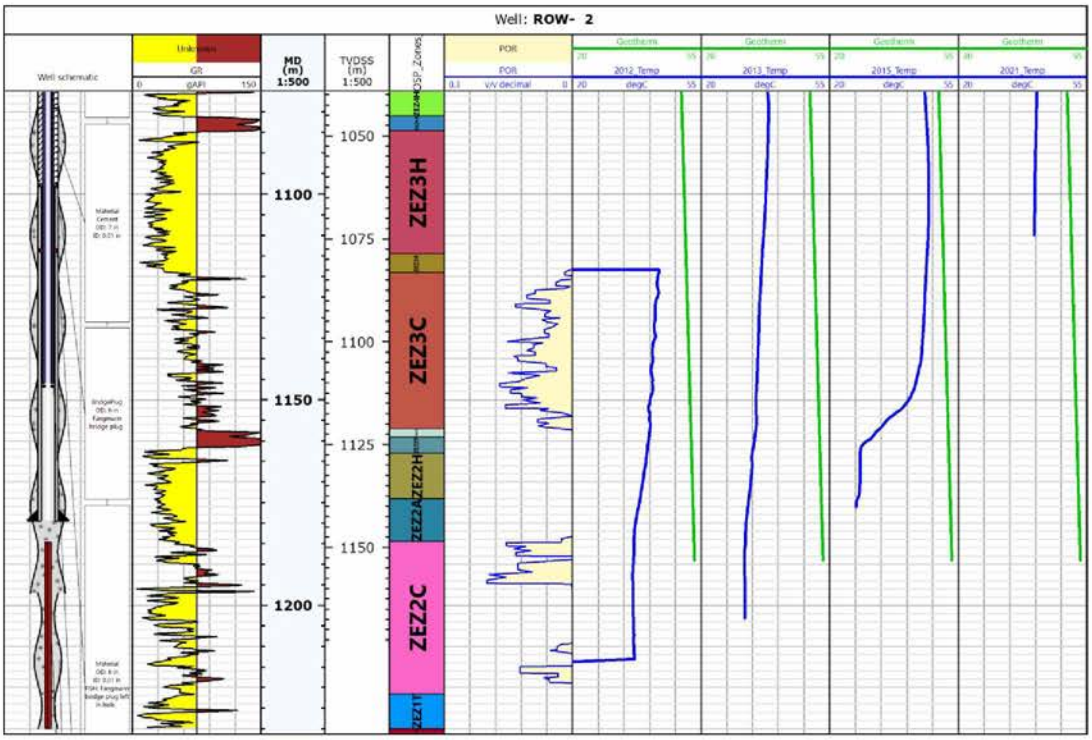


Figure B-1: Temperature survey in ROW-2, the survey in 2012 was taken after 129 days shut-in which was preceded by injection of 50000m³ cold (15 deg C) water over a period of 63 day.

B.2 ROW-3

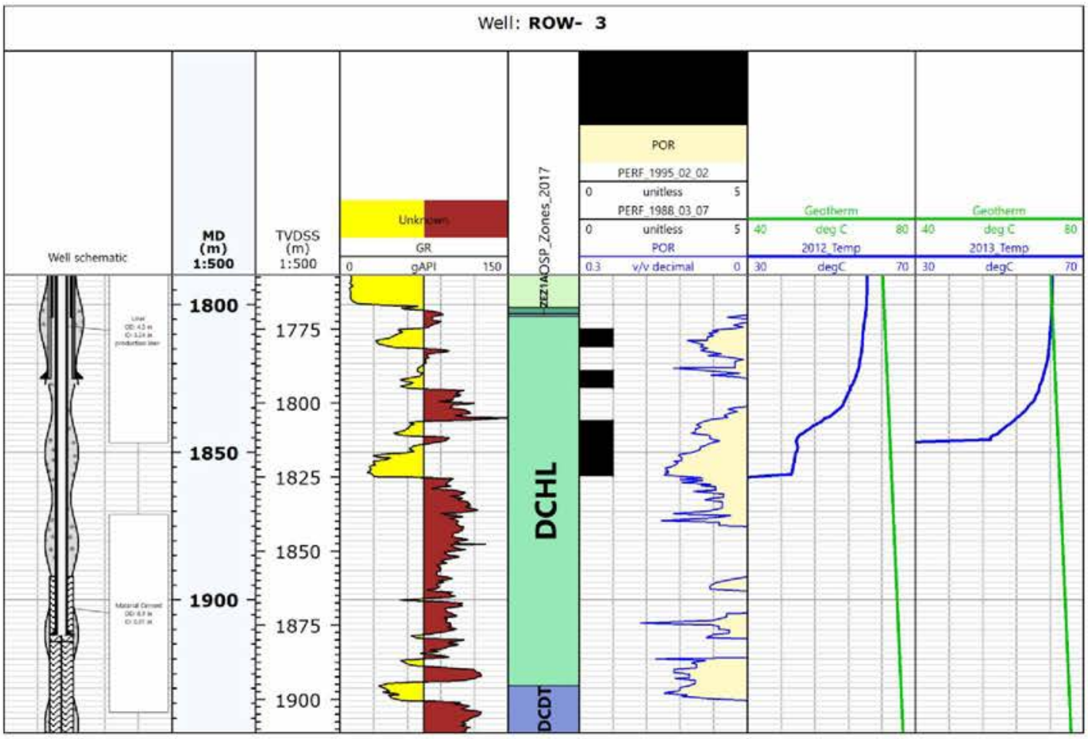


Figure B-2: Temperature survey ROW-3 in 2012 was taken after 4 days shut-in which was preceded by injection of 600m³ cold (15 deg C) water over a period of 1 day

B.3 ROW-4

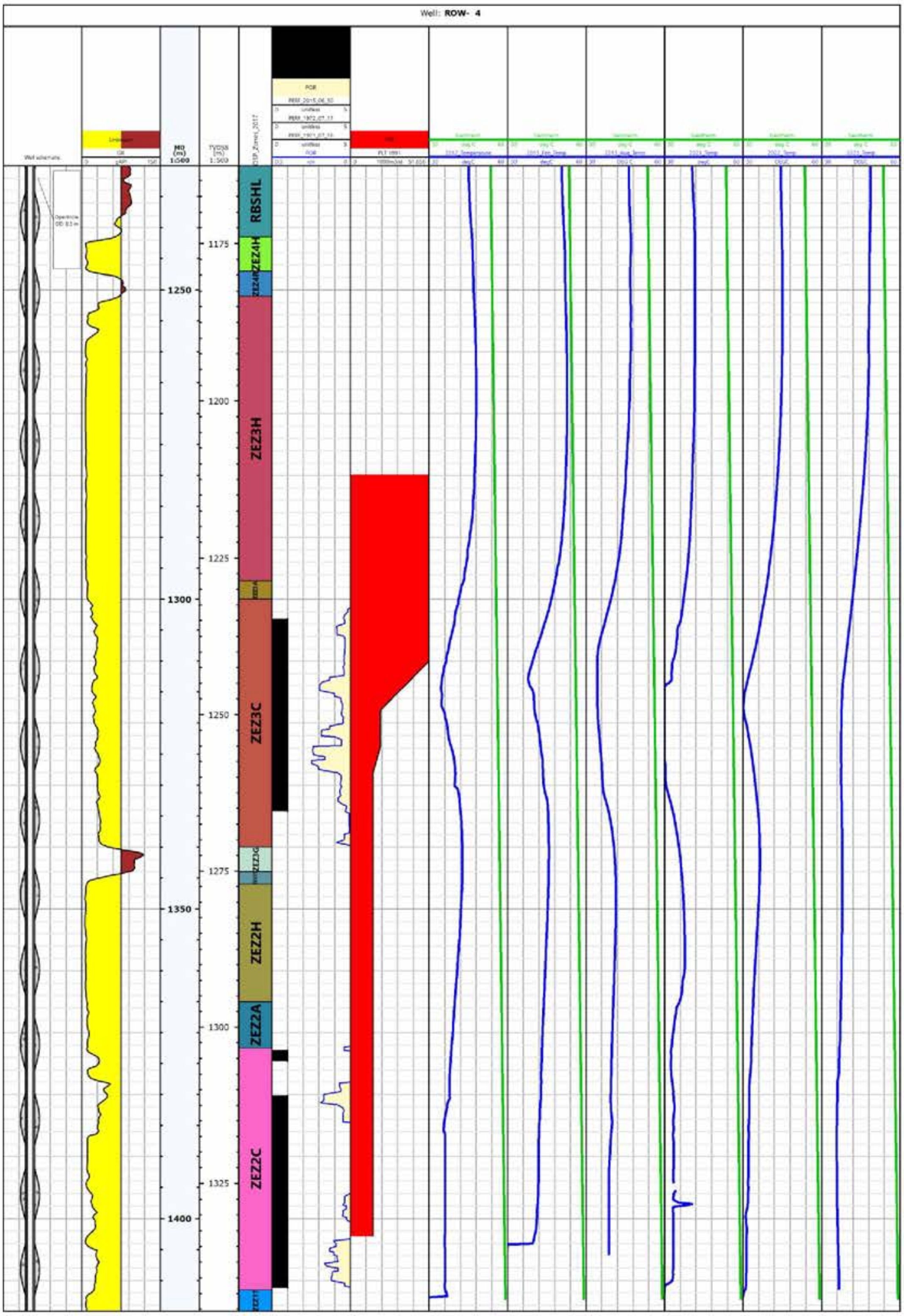


Figure B-3: Temperature survey of 2012 was taken after 21 hours shut-in which was preceded by injection of 1200m³ cold (15 deg C) water over a period of 20 days.

B.4 ROW-5

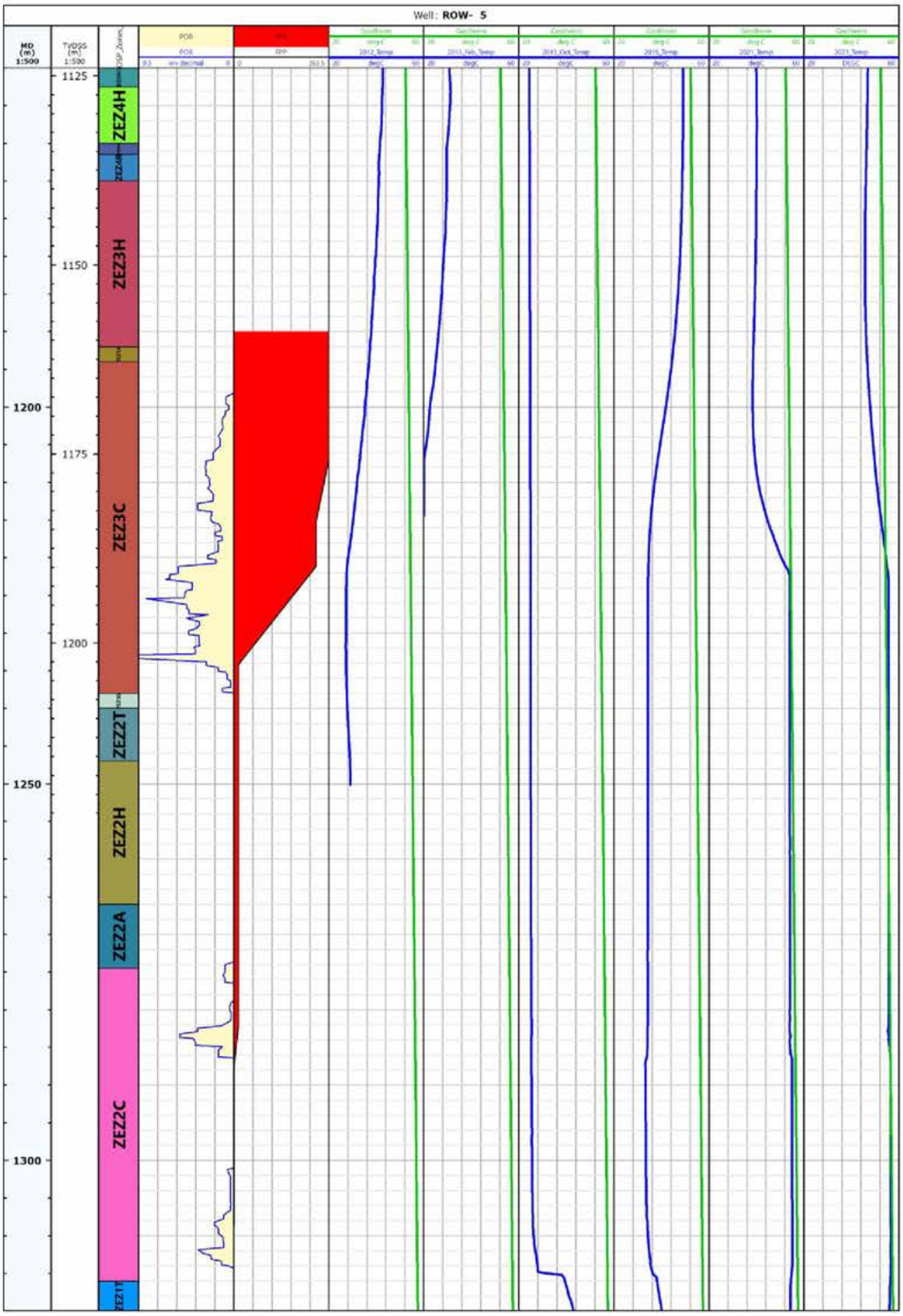


Figure B-4: Temperature survey of 2012 was taken after23 hours shut-in which was preceded by injection of 1000 m³ cold (15 deg C) water over a period of 18 days.

B.5 ROW-7

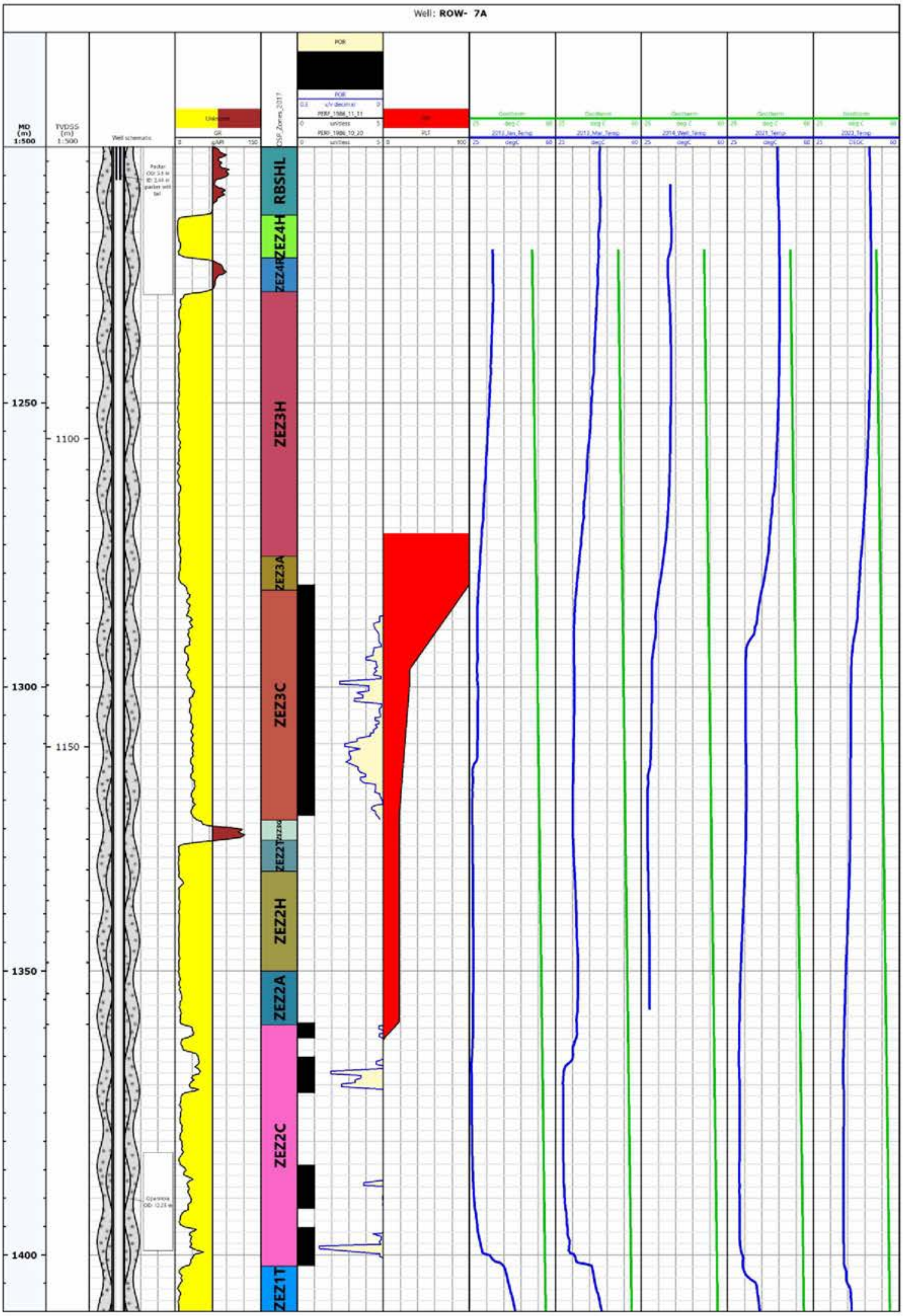


Figure B-5: ROW-7 temperature survey, in January 2013 was acquired after 26 hours of shut-in, which was preceded by injection of 28000 m³cold (15 deg C) water over a period of 31 days.

B.6 ROW-9

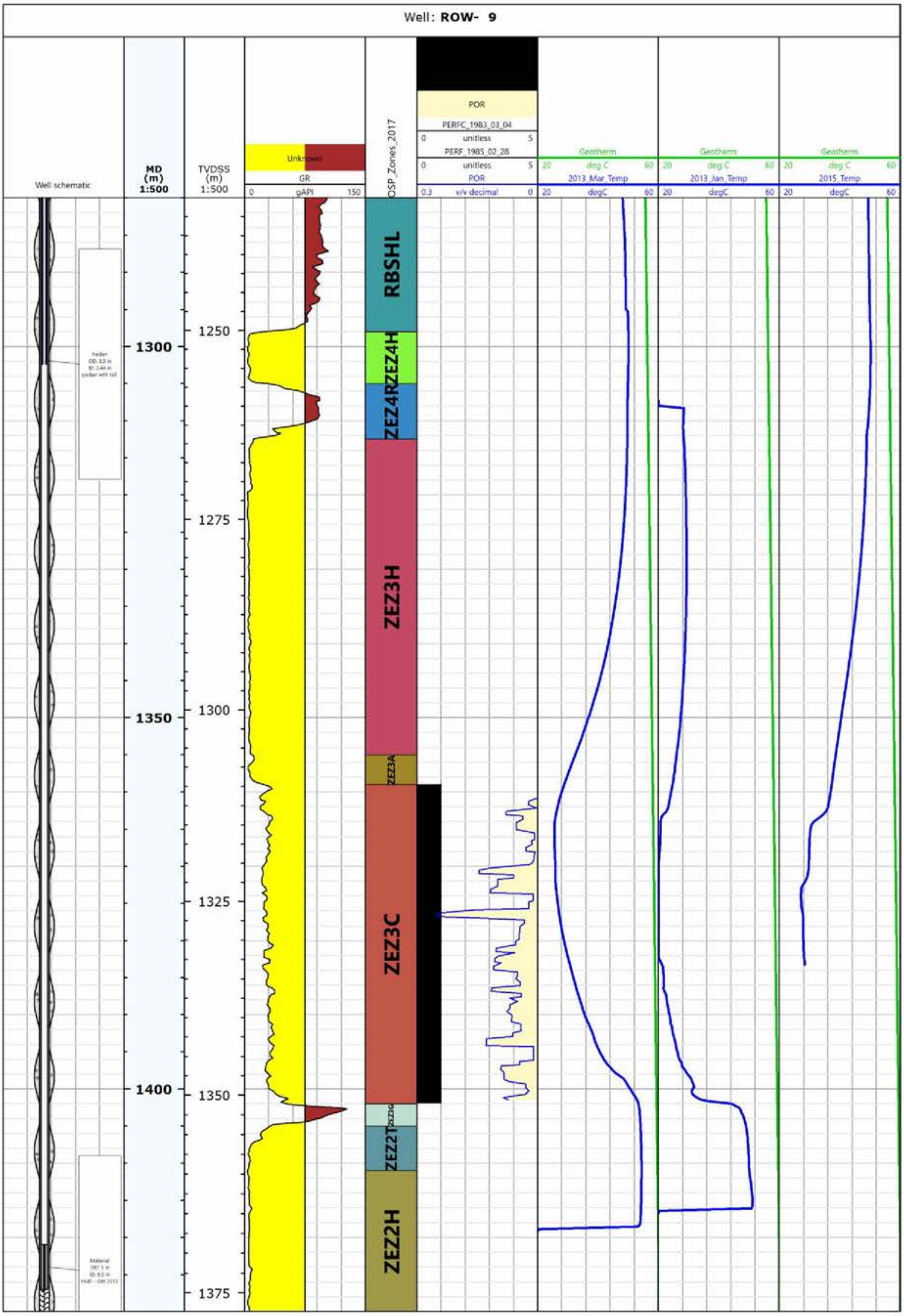


Figure B-6: ROW-9 temperature survey of December 2012 was acquired after 6 hours of shut-in, preceded by injection of 11000 m^3 cold (15 deg C) water over a period of 17 days.

Appendix C Measured reservoir pressures

well	Date	Cum Well Injection [mln m3]	Datum pressure [bara]	measured pressure at top perforations [bar]
ROW-2	01/01/2009	0.00	6.9852	6.9
ROW-2	04/11/2011	0.06	10.0	9.9
ROW-2	30/11/2012	0.11	10.6	10.5
ROW-2	02/10/2013	0.29	*	16.3
ROW-2	10/04/2014	0.53	41.4	31.9
ROW-2	15/09/2015	1.09	31.2	22.7
ROW-2	01/11/2016	1.12	28.9	19.9
ROW-2	22/06/2017	1.48	39.9	31.4
ROW-2	09/10/2018	2.12	43.7	34.7
ROW-2	12/11/2019	2.60	43.7	34.9
ROW-2	15/12/2020	2.63	40.2	31.5
ROW-3	01/01/2009	0.00	70.8	70.7
ROW-3	07/11/2011	0.01	122.0	119.5
ROW-3	05/03/2012	0.02	108.7	106.1
ROW-3	11/12/2012	0.02	135.2	132.6
ROW-3	14/02/2013	0.02	122.2	119.6
ROW-3	19/11/2013	0.03	141.6	139.1
ROW-3	26/02/2016	0.04	119.3	116.8
ROW-4	01/01/2009	0.00	7.6	7.7
ROW-4	08/11/2011	0.05	51.5	53.6
ROW-4	11/11/2011	0.05	44.7	44.7
ROW-4	12/12/2012	0.11	37.9	40
ROW-4	30/12/2012	0.11	37.1	39.2
ROW-4	14/02/2013	0.12	53.1	55.2
ROW-4	09/04/2014	0.25	36.4	36.5
ROW-4	25/09/2014	0.29	57.9	59.9
ROW-4	01/09/2015	0.40	36.6	38.6
ROW-4	08/11/2016	0.44	84.7	86.7
ROW-4	13/06/2017	0.63	58.1	60.1
ROW-4	02/10/2018	0.97	64.6	66.8
ROW-4	06/11/2019	1.38	72.3	74.4
ROW-4	10/11/2020	2.01	75.1	77.3
ROW-4	21/01/2021	2.10	51.9	53.9
ROW-4	19/06/2021	2.34	64.9	66.9
ROW-4	23/11/2022	2.50	41.3	43.2
ROW-4	19/09/2023	2.50	39.0	41

ROW-5	01/01/2009	0.00	6.2	6.1
ROW-5	09/11/2011	0.03	7.8	7.8
ROW-5	11/11/2011	0.03	8.1	8
ROW-5	30/11/2012	0.13	12.6	9.1
ROW-5	20/01/2013	0.13	8.9	8.8
ROW-5	14/12/2013	0.19	9.3	9.2
ROW-5	21/10/2014	0.28	16.6	10.3
ROW-5	23/09/2015	0.43	19.5	12.6
ROW-5	23/09/2015	0.43	19.8	12.9
ROW-5	10/11/2016	0.45	20.3	13.9
ROW-5	14/06/2017	0.49	22.7	16.1
ROW-5	04/10/2018	0.76	28.7	21.8
ROW-5	14/11/2019	0.94	28.6	22.2
ROW-5	12/11/2020	1.24	32.4	25.7
ROW-5	24/06/2021	1.33	32.4	25.6
ROW-5	29/11/2022	1.42	26.7	19.8
ROW-5	21/09/2023	1.42	25.8	19.3
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	0.23	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-7	09/11/2021	1.36	45.3	31.9
ROW-7	16/11/2022	1.36	40.4	27
ROW-7	27/09/2023	1.36	38.1	25.2
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

*) unknown fluid gradient for converting from downhole gauge to datum level

Appendix D PNL logging results

D.1 ROW-4 Composite Plot: comparison of 2021-2022-2023 measurements

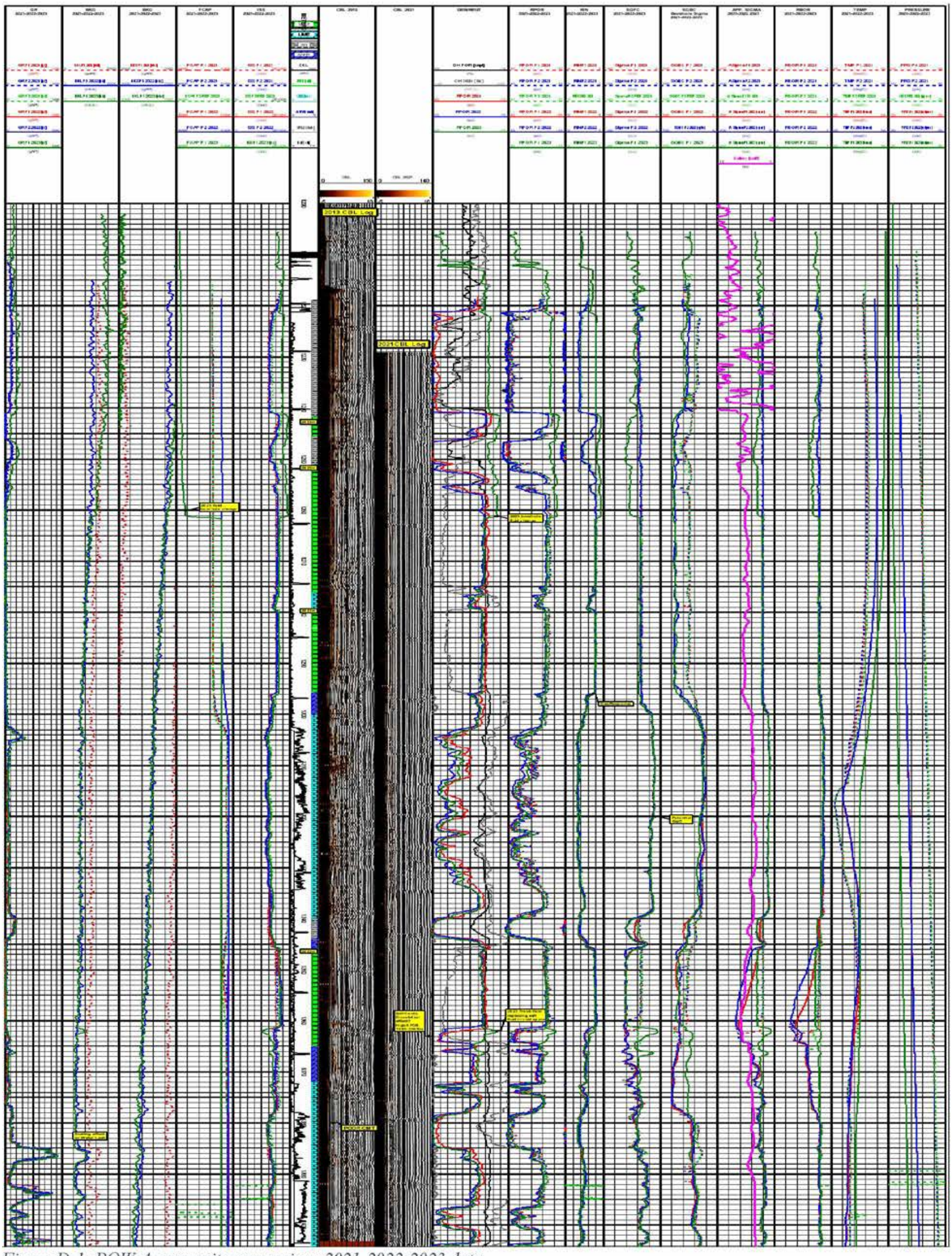


Figure D-1: ROW-4 composite comparison 2021-2022-2023 data

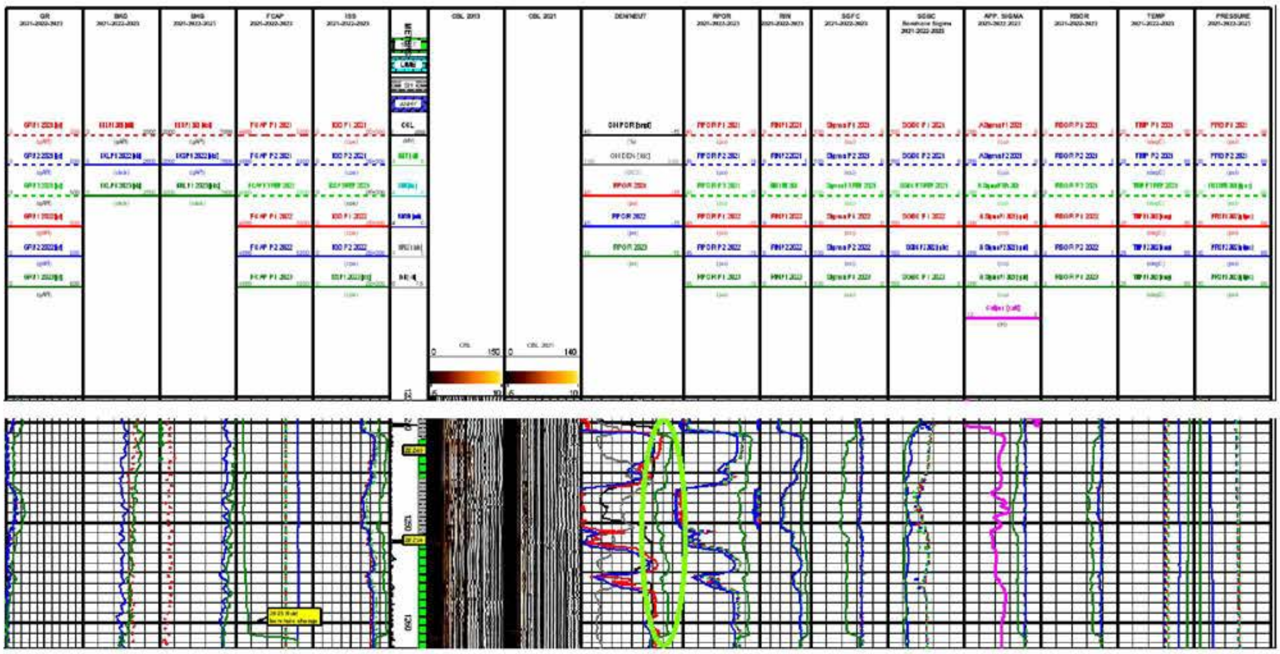


Figure D-2: ROW-4 Pulsed neutron log composite including borehole caliper and cement log and indicating the change in response, due to the possible gas presence in the borehole

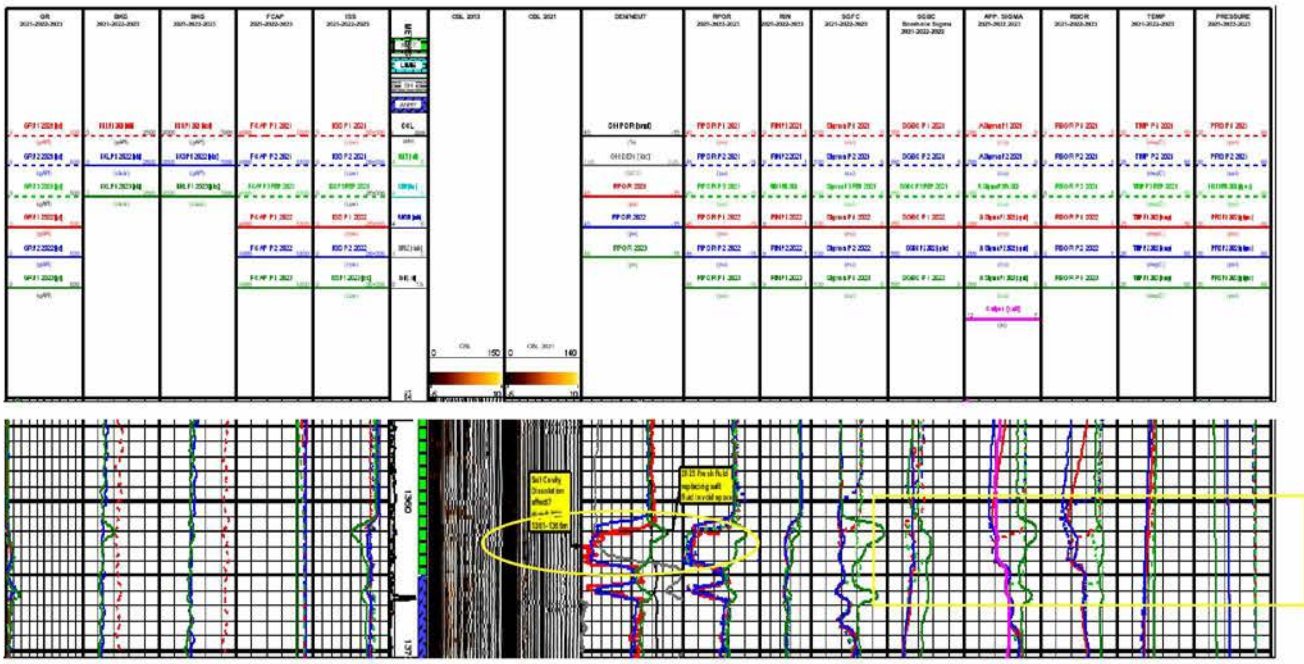


Figure D-3: Expanded section in base of Halite ZEZ2H to highlight the changes in Apparent Sigma, RPM porosity (1360-1365.5m). Yellow Circle focuses on the unchanged void thickness visible from 2021 application, while Yellow Rectangle indicated the change of salinity range along the SALT ZEZ2H meaning fresh water. A low salinity water flush is done just prior to logging to ensure access, this has most likely affected the log response observed here.

D.2 ROW-5 Composite Plot: comparison of 2021-2023 measurements

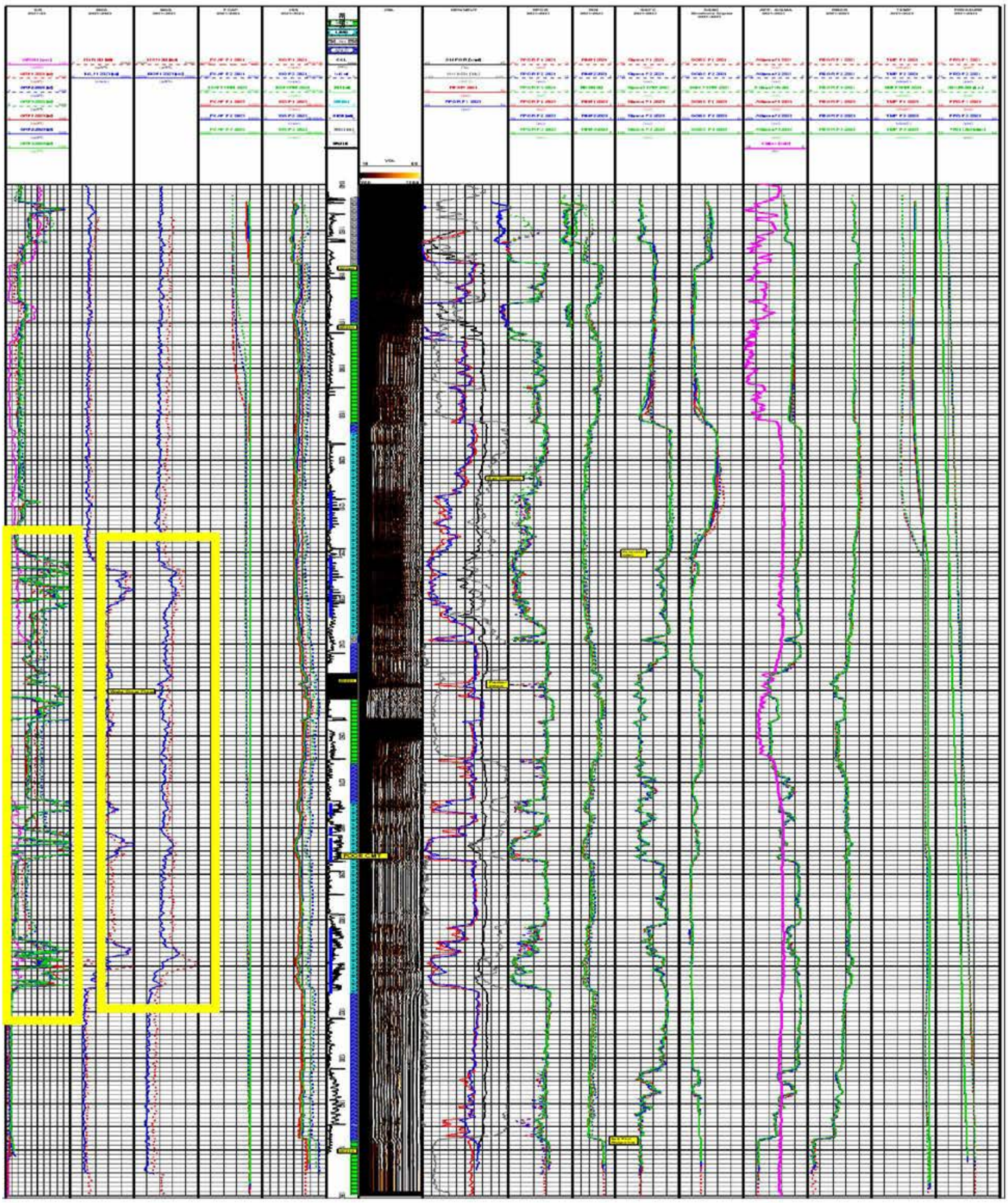


Figure D-4: Row-5 composite comparison of 2021 and 2023 data. The Oxygen activation indicators in the yellow rectangle highlight the potential water flow between the upper and lower perforations.

D.3 ROW-7A Composite Plot: comparison of 2021-2023 measurements

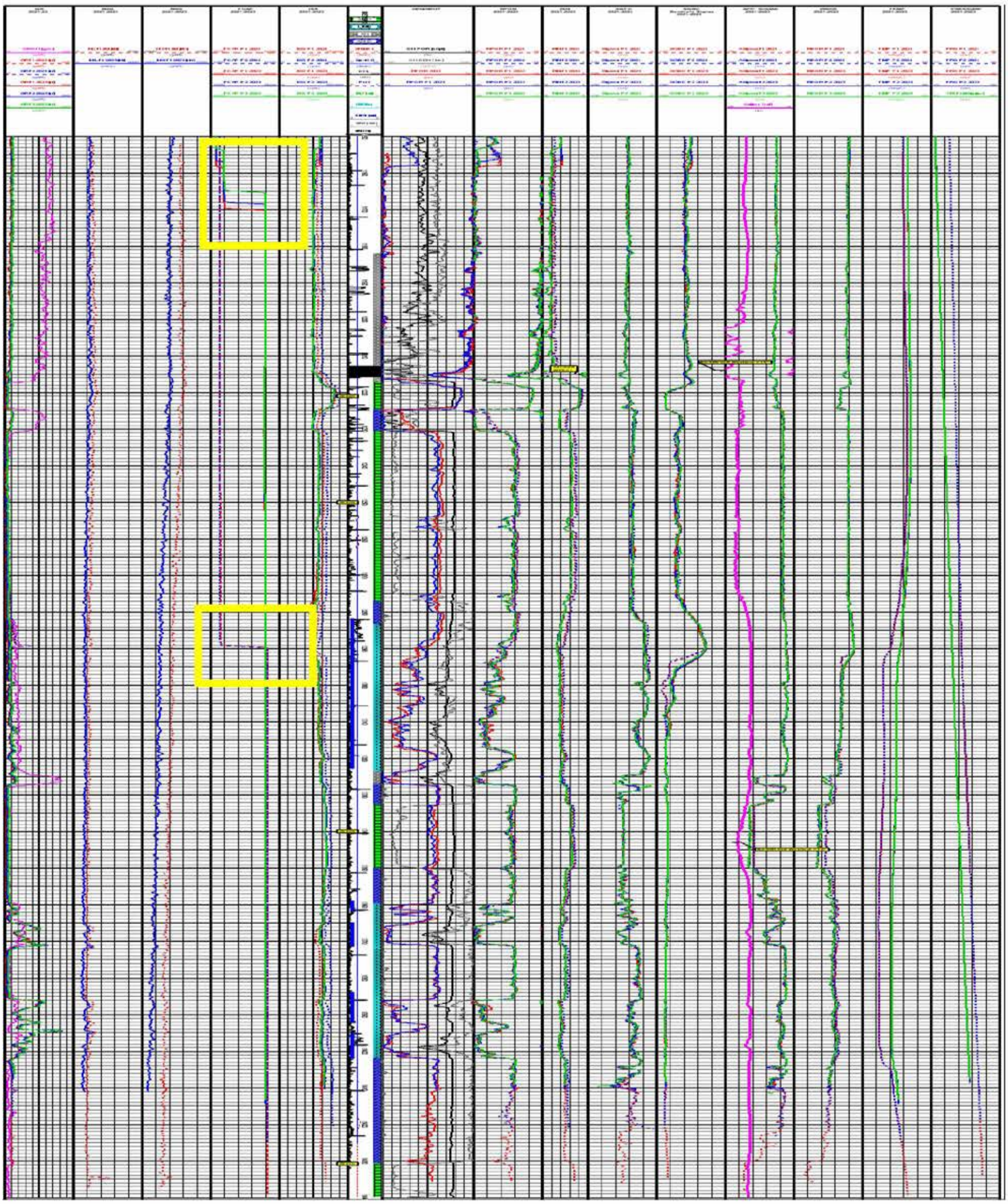


Figure D-5: Row-7A composite comparison plot from 2021 and 2023 does not indicate relevant changes in salt layers. Only a fluid interface from water to gas is visible at 1170m from previous 2021 contact (Yellow rectangle)