Review of ROW-2 Well Integrity Investigation May 2021 EP202104200659

Final Report

30 June 2021

Purpose

This report provides the results of a review of data and of a report providing analysis of the events leading to the loss of the ROW-2 well as a Twente waste fluid injection well. The review is intended to assist the Netherlands Ministry of Economic Affairs and Climate Policy Consulting Authority, State Supervision of Mines in its assessment of this report, and to provide insights and guidance for its recommendations to the Operator, as well as answers to a series of questions posed by Ministry in soliciting this review. An Executive Summary providing answers to the three primary questions is followed by a discussion of the implications and further thoughts. This is followed by a series of Appendices including the list of documents reviewed, a bulleted series of answers to the main questions prepared as a preliminary report for discussion, and answers to specific questions revised based on the Ministry's review and comments on the preliminary report. A final Appendix shows the ROW-2 well completion, and the locations of tubing constrictions and of formation tops in the critical completion interval of the ROW-2 well.

Report Executive Summary

The principal goals of the Report being evaluated in this Study are to explain the loss of ROW-2 as an injector, and to address the implications for the other injection wells in the field or in similar fields. Specifically, the questions to be addressed, and the high level answers, are:

1. What has happened? Tubing deformations have occurred over time throughout the life of the ROW-2 well within the ZEZ3C interval. A casing shear displacement at the depth of the shallowest tubing closure allowed connection of the ZEZ3C to the annulus, and would have allowed injection into the ZEZ3C as soon as deformation caused a tubing breach. Tubing damage did occur, and was almost certainly caused by the casing deformation. Monitoring data was provided e.g. of annulus pressure and fluid level, and in hindsight this situation could have been identified much sooner if this data had been collected more frequently and if more attention had been paid to it. That said, there is no evidence in the report to indicate that injected fluid was lost other than into the ZEZ2/ZEZ3 zones of injection in this field. This is a fortunate consequence of injection well completion design.
2. What is the underlying cause of this incident? The primary cause of tubing deformation is casing lateral deformations exerting loads on the tubing. It is possible that there was an additional contribution to failure from axial shortening loads (tubulars are weaker under complex loading conditions); in other words buckling may have been involved. These incidents occurred in lower strength sections; undoubtedly this also contributed to the severity of deformation. Such sections would be expected to fail first even if loads were exerted across longer intervals. Formation loading was the cause of casing lateral deformation, either due to shearing along shallow-dipping interfaces or to low shear-rate deformation of ductile layers; deformation loaded the casing and the critical failure occurred near the interface between softer and stiffer materials. It is unclear whether additional deformation, for example, axial loads exerted over the ZEZ3H section due to (salt) dissolution contributed, or if mineralogical phase transformations of anhydrite to gypsum may have played a role. There is no definitive evidence to determine whether the intervals affected were exposed to injected (chemically incompatible) fluids. It is possible that the Fall 2017 sudden loss of tubing pressure was caused by the incident; it is also possible that it triggered the incident and was caused by something else, either a loss of packer integrity or a surface leak; but even if so the incident would eventually have happened.
   Although it is more likely that the measured casing shear predated the work over, it could be that prior to the work over the tubing had provided partial support of the casing, which when removed during operations allowed further casing displacement to occur; if so the measured offset does not provide information about the magnitude of any shearing incident that may have occurred to cause tubing deformation. it is notable that local seismic monitoring systems were sensitive enough and did not detect a seismic event of sufficient magnitude to explain the full displacement. The Report adequately addresses these causes (with the exception perhaps that axial loading was not discussed and its unclear if the possibility of a surface leak was addressed) and concludes that there is no clear evidence to eliminate either of the explanations it proposes.

3. <u>What are the implications of this for future water injection activities in similar cases?</u> The ZEZ3C, as for the other intervals under injection, will deform over time, and those deformations will exert point shearing loads on any completion; deformations are likely also within the unsupported intervals of this formation into which injection is occurring even where highly deformable intervals have not previously been identified; salt dissolution and conversion of anhydrite to gypsum will be more likely within injection intervals because they will have exposure to multiple pore volumes of incompatible fluids. Thus, while conditions at ROW-2 combined to cause it to fail first, such deformations are undoubtedly occurring within the sensitive intervals of other injectors. Monitoring is essential to identify when and where this occurs. Other measurements of well integrity need to be made more frequently than at present. Together this includes to measure tubing shape (bend radius and cross-sectional shape), to ensure integrity and isolation of each wellbore volume for example by conducting tubing/annulus pressure/flow tests at regular intervals, to track fluid levels and pressures to determine continuous pressure profiles vs. depth in the annulus and in the intervals connected to the injection zones, and to detect changes e.g. in reservoir conditions that may reveal problems that require mitigation, for example by measuring injectivity.

Of primary importance for the future is that many (although not all) of the geological conditions that contributed to the ROW-2 incident are present at other wells. Differences in well location w.r.t. the geological structure, and in completion type and completion location in the geologic section, mean that the specific symptoms and consequences will be different and the onset may be delayed.

The well completions are designed to minimize the consequences of such similar incidents. It is fortunate also that the critical elements that ensure the integrity of the completions in the other wells are not adjacent to the intervals where these incidents are most likely to occur.

The goal should be to monitor, at more frequent intervals than is now done and with more frequent and more careful reporting, to anticipate the imminence of such incidents and to ensure well integrity in other words that the wells are capable of performing as designed; perhaps to tag fluids so that they can be tracked by fluid sampling to determine if leakage across barriers within the well or the reservoir has occurred; and to conduct operations so as to minimize future problems, for example to reduce the geochemical risks of salt dissolution by modifying the chemistry of injected fluids.

Regarding the leak that allowed the fluid pressure drop to zero at surface which occurred in Fall 2017, there is no information that would allow determining if it occurred at depth or at surface. Determining that would require continuous monitoring of fluid height and a pressure sensor that can detect levels of vacuum. If pressure loss occurred at surface, and fluid in the annulus was already depressed relative to design level, the pressure difference across the tubing could have been much larger than anticipated, and, the differential pressure change could have been abrupt.

The reservoir and geomechanical modeling discussions in this report are its weakest sections. Some effort should be expended to address a large difference between pressure measurements and the predictions of injection models that was reported in an accompanying document.

The cost and effort associated with building and calibrating a proper reservoir model of these fractured reservoirs, in which flow is carried along preferred pathways and permeability is strongly sensitive to local stresses and their changes, and in which pore volume collapse perhaps significantly decreased storage volume (porosity), would be significant. However, limited modeling contained by the appropriate measurements could help to provide a risk assessment of the likelihood of future problems for example if the injection pressure were to increase faster than anticipated. Better well tests, with sensors placed below fluid levels, should also be conducted. Details and suggestions for future monitoring are provided below.

Discussion and Further Thoughts

The principal evaluation result is that the scenarios(s) proposed in the report are both reasonable to explain the casing shear and tubing collapse (and the associated loss of apparent A-annulus integrity to the ZEZ3C, and connection during work over to this well's ZEZ2C injection interval). But they are impossible to choose between given the available data. This is because there is no way to know if the packer leaked first (or if a leak occurred at the surface leading to an unknown pressure drop at depth), or if the well/tubing sheared first causing the pressure drop. The specific conditions external to the well that created the conditions to cause this event also remain largely unknown, as there are no measurements, for example, of local pressures / temperatures / strains / stresses in the rock surrounding the well, or of the presence of fluids which could have altered the properties of the shale layer. It is also unknown when exactly the shearing displacement occurred; whether suddenly when the A-annulus pressure dropped suddenly to zero, or aseismically over time during, preceding or following that pressure drop. It would be appealing to assume that the pressure drop coincided with a shearing event, however that is probably unlikely as (a) there was no event as such recorded on seismic monitoring equipment, and (b) there was no immediate tubing deformation at the event depth, so additional casing displacements would have had to occur over time.

The assertion that no overall loss of well integrity occurred is likely correct, though no well integrity test data following the event has been provided; in fact, the event did connect the A-annulus to the ZEZ3C formation at the depth of the sheared casing. Thus there is no guarantee, as the Report itself states, that the ROW-2 well did not begin injecting into ZEZ3C following the event. This might have been revealed through injectivity or other well tests conducted with downhole pressure sensors. However, this integrity loss is also not important, as offset wells are actively injecting into this interval. The report states that the injection intervals are in pressure communication however no supporting data is provided.

There is no evidence of a breach of annular isolation into overlying formations (and the casing inspection logs confirm the casing physical integrity). The risks of injection at the top of structure at the location of ROW-2, into the ZEZ3C interval, for which the injection plan has not been designed, have not been evaluated.

Regarding the likelihood of prediction of events of this type (extreme deformation of casing leading to casing breach and/or leading to connection of the A-annulus to the injection flow path) in the other wells of this field, this would require considerable additional geomechanical data. And, the location in the geological section of the interval within which the consequences would be the same (i.e., above the isolation packer where tubing passes through cemented casing) is above the ZEZ3C in the other wells. However, a more useful question to address is whether (1) the imminent occurrence of a precipitating shear event might be detectable before it caused problems, and (2) the consequences can be predicted and a plan for mitigation of those consequences can be developed.

Casing or wellbore shear is always a possibility especially when large changes in pressure due to depletion are followed by later pressure increases due to injection. Juxtaposition of stiff / brittle layers against softer, deformable or viscous layers, causes nucleation of loads at the interfaces which are amplified if clay-bearing, potentially ductile shales are present. Thus the highest likelihood locations at which these events could occur might be predictable.

The risk of an *identical* event causing casing/tubing breach as in ROW-2 is small in the other current injection wells in this field, for all of the reasons stated in the Report. That does not mean the risk of a *similar formation deformation* event should be ignored - in fact, such events are likely although they would not, because none of the wells have casings extending across the most likely geological interval of occurrence, result in the same kind of casing/tubing breach above the isolation packer. That said, this was an event which occurred due to the unrecognized juxtaposition of a relatively weaker completion adjacent to a geological interval with a much greater likelihood of exerting large loads on the casing, in a zone into which injection is occurring in nearby wells, at the top of the structure where smaller pressure changes and fluid replacement of gas by (fresh) water may have larger effects than on the flanks. Other unrecognized situations may exist; in fact it is less likely though possible that overlying horizons could deform enough to cause casing loads to impinge on tubing above the isolation packer. Thus it is important to monitor to detect (more often than was done in ROW-2) and design to mitigate the effects of such events, rather than to rely on preventing or predicting them.

Further thoughts and the preliminary answers to the general questions, and revised answers to the specific questions to be addressed for this review are included below in a series of Appendices. Also in an Appendix is a well diagram of ROW-2 within the affected interval which includes some details about the completion and shows the locations of a series of tubing constrictions that were identified at progressively shallower locations in the well over its lifetime. This progression is most likely because once a constriction is present it's not possible to run tools below it; however if the progression is real it could be related to the process which led to the incident under review.

Appendices

Appendix I. - List of Reviewed Documents

Appendix II. - Preliminary Responses to Questions June 14 2021

Appendix III. - Detailed Answers to Specific Questions

Appendix IV. - Figure showing locations of tubing deformations detected over the life of the ROW-2 injector

Appendix I. List of Reviewed Documents

Received as requested for additional review 2021-06-02

1. bijlage-1-beantwoording-vragen-over-weergave-gegevens-eindrapport-herevaluatie-verwerking-productiewater-schoonebeek.pdf (in Dutch) - 06-Dec-2016 letter with report referred to in the ROW-2 integrity review related to reservoir / geomechanics modeling

Received as email attachments 2021-06-01

2. ROW-2 InTex CBL interpretation.pdf - Baker Hughes InTex casing bond log acquired 22-Feb-2021
3. ROW-2 LIB photo's.pdf - rig-site photos of cut tubing and LIB recovered from ROW-2
4. ROW-2 Shear 7inch Prod. Casing.pdf - images acquired 20-Feb-2021 using downhole camera after cutting tubing in ROW-2
5. ROW-2_A-Annulus_Pressure_History.pdf - figure showing A-annulus pressure data acquired since October 2016 in ROW-2
6. ROW-2_FORMATION TOP DATA.pdf - table of formation depths of formation tops, some with dip and dip direction (14dip; 41azi), for ROW-2
7. ROW-2_Well Status Diagrams.pdf - showing formation tops, completion diagram, and locations of various events
8. Casing_Caliper_Analysis_Report_ROSSUM_WEERSELO_2.pdf - ROW-02 7" casing SCMT-PMIT interpretatie
9. Supporting email from the NAM (mostly in English)
10. ROW panel top 3C.pdf - Rossum-Weerselo panel (logs) leveled at top Zechstein 3C.
11. ROW-2_SCMT-PMIT_evaluation_Oct-2013_EP201310209305.pdf - Multi-finger Caliper Analysis Report of February 17th 2021
12. ROW-2 4inch tubing fish (1).pdf - Various pictures of the underside of recovered tubing
13. Winningsplan Rossum-Weerselo - field development plan.pdf - 19 december 2003 plan document

Received as email attachments 2021-05-28

14. DOMUS-21104157-v4-Input_reviewer_ROW-02.pptx - additional detailed questions to be addressed
15. Technisch evaluatierapport Waterinjectie Twente - kenmerk EP201701214429 - april 2017.pdf - the operator's required 6-year injection report for the Twente injection wells including ROW-2
16. 2017 Twente waterinjectie - EP201801202157 - FINAL.pdf (in Dutch) - injection well report data
17. ROW-2 Well integrity investigation May2021 EP202104200659.pdf - report on ROW-2 well integrity to be reviewed in this project

Also reviewed

18. 6-dr-ellsworth-review-of-twente-threat-assessment.pdf - microseismic monitoring plan review

Appendix II. - Preliminary Responses to Questions June 14 2021

What has happened (preliminary conclusions)?

- There was a total and unexplained loss of (2-4 bars) annular pressure maintenance in ROW-2 in late 2017, followed by slow recovery. If this was due to loss of packer integrity and the well was sealed at surface, it could have created a vacuum - but the data shows only that pressure went to zero, not the location of the leak.
- Tubing ovalization had been detected at several points opposite the ZEZ3C prior to and following this pressure loss event; locations got progressively shallower as time went on
- Casing shear displacement is inferred to have caused ovalization of injection tubing at 1116 m approximate depth in late 2019, leading to inability to run tools into the well
- A-annulus fluid level measured in early 2020 while servicing surface equipment was lower than expected
- The well was worked over revealing details of the deformation and damage
- There do not appear to have been any proven adverse consequences other than loss of this well which was a highly effective injector - this in part because the breach was at a shallower injection zone where fluid loss posed no risk

What is the underlying cause of this event (preliminary conclusions)?

- The event was caused by formation loads concentrating deformation at the depth of a shale layer near the top of the ZEZ3C.
- Alternative explanations e.g. axial loading causing buckling are unlikely but possible contributors
- Formation shear and deformation exceeded casing deformational load limits.
- There is not enough information to unambiguously explain the cause of the formation shear; it likely did not occur instantaneously but rather developed over time.
- Additional contributors include loss of internal annular pressure which otherwise might have supported the casing against the shear event, and a low collapse rating for the casing and, in the interval where the tubing failed, the tubing system itself.
- There were deeper locations of tubing ovalization, the causes of which have not been fully explained, which were not associated with a weak shale layer.

What are the implications of this for future water injection activities in similar cases (preliminary conclusions)?

- Appropriate isolation should be maintained such that a similar event does not compromise
    - well integrity
    - well performance
- This includes ensuring that critical completion elements are protected from excessive deformation, for example, by placing them in such a way as to isolate risky intervals from the rest of the well even if an event were to occur
- Monitoring should be improved based on watching for and reacting appropriately to the predicted symptoms of imminence or occurrence of similar or related failures
- Prediction will be difficult - it is better to measure precursors of such events and design for mitigation their effects

Appendix III. Detailed Answers to Specific Questions

Data:

- **Is the database sufficient to be able to understand the geo-mechanical process leading to the shearing event**
    - Fundamentally, no. The cause could have been shear failure on a fault, or bedding-plane slip on a near-horizontal layer, or differential strain rates between the 3C/3H. Modeling could be carried out to test whether one or more of these could have occurred, however the results would be difficult to validate as the required data may not be obtainable.
        - geomechanical measurements (micro-frac tests to measure S3; long term shut-in to determine pore pressure) would provide information on the reservoir stress path. This could be done through perforations in casing. Perhaps, stress orientation could be detected, or fracture orientations if those are aligned, or bedding dips if those are steep enough, using acoustic measurements of shear-wave azimuthal anisotropy; this is possible in a cased well though it might require pressurizing the well to ensure good casing connection to the formation. Together these would provide constraints on how slip might have occurred given the orientation of the slip plane if that could be determined.
        - Note a vertical profile of stress measurements would be very informative regarding how to model differential deformation with depth and at interfaces.
        - Laboratory creep and mechanical properties testing of samples from the affected intervals could inform models of time-dependent deformation. Compaction studies could provide estimates of stress path changes between depletion and injection, and the degree of irreversible compaction that resulted form production-related pressure drops.
        - Fluid compatibility testing could help determine the extent to which incompatible fluids contacting the affected intervals might have altered their properties and perhaps contributed to the event occurring.
        - Direct fluid sampling of intervals at appropriate locations, and measurement of e.g. oxygen isotopes, might identify injected fluids even if those were not previously tagged thereby helping to map fluid injection pathways.
    - If differential displacement across the 3C/3H boundary, localizing forces leading to bedding-parallel slip within the “shale,” then so many ambiguities exist that it would be difficult to resolve them even with more “geomechanical” data
        - installing fiber to measure deformation would be one way to monitor for and anticipate similar events

    - using laboratory measurements of creep rates under realistic in situ conditions in the various materials to constrain models for how the system is loaded; following that with FEA of the completions given those loads

    - using real-time or semi-continuous measurements of fluid level, e.g. echo-meter or other fluid level monitoring of the annulus, along with surface pressure monitoring, can provide key information for well / annular integrity

    - direct fluid pressure monitoring and sampling of the annulus could be carried out on an ongoing periodic basis if capillary tubing or other sampling systems were to be deployed.

  - If shear failure due to "fault slip" of a shale layer, there are a number of possible causes; elevated pore pressure; hydrological weakening of the shale; differential deformation of the reservoir in response to withdrawal and injection over time; natural growth of the salt structure without regard to operations; all could be contributors, and extensive modeling, monitoring, and data gathering would be required to create plausible scenarios that explain the event.

- **What data may be useful to better understand the geo-mechanical process**

  - Reservoir related data is not discussed in much detail in this Report. These are fractured reservoirs, modeling results using equivalent poroelastic media are approximations at best (I note with concern the large under predictions of injection related pressures, which are explained by differences in water vs. gas mobility) though such models can be improved with measurements for calibration

    - knowledge of reservoir pressure variation with time and location, from initial production through current time - I note that the pre-production pressure and ultimate depleted pressure are provided, but discussion is minimal of how they developed and the consequences of changes on stresses and stability of structures

    - knowledge of depletion and injection stress path

    - poro-elastic / poro-plastic parameters of the reservoir material

    - interference or other testing to establish flow paths / connections between locations and between the different geological horizons

    - formation wet ability - water-wet? oil-wet? can be critical - which fluid if partially saturated carries the pressure gradient? Can hydrolytic weakening contribute to failure?

  - stress orientations and magnitudes / changes with pressure - it has been assumed that horizontal stresses are the same, and no information on stress orientation is presented

  - orientation of slip planes / possible displacement surfaces (dip-meter?)

- **Would directional data of present day stress and/or deformation of tubulars add to the understanding and possible modelling**
    - yes, but not by itself
    - this region is remarkably seismically quiet; this is unfortunate because microseismic monitoring and focal mechanism determinations could provide information on the local strain tensor and identify zones where conditions are approaching seismic stability limits of pre-existing faults or fractures
    - direct pressure measurements between injectors, and interference testing if possible, would allow monitoring fronts, determining permeability anisotropy associated with fractures and faults, and help predict reservoir filling / fluid distribution to allow comparison to microseismic activity;
    - see above; shear-wave anisotropy might reveal the orientation of the maximum principal stress if the material is sufficiently stress-sensitive and if the stress difference is large enough.

Described underlying cause as given by NAM

- **Are more, realistic, scenarios possible than those (2) proposed**
    - No, although the event sequence might have been different, or other loadings might have contributed to tubular deformation and failure.
    - It's remotely possible and likely un-knowable that the pressure breach occurred at the surface rather than downhole - the fact that pressure went to zero, and not below zero or close to but not zero, is interesting from this perspective. In order to differentiate between a surface and a reservoir-level breach it would be necessary to continuously track fluid level especially during sudden pressure changes and/or install a pressure sensor that can measure vacuum levels.
    - One possibility is that some of the casing shear occurred at the time of removal of the tubing; if so, it's possible that the well casing was intact (although deformed) but there was a loss of A-annular isolation from the reservoir at a previous time, not through a tubing breach - which would favor scenario B. While unlikely this could probably be eliminated as a possibility using extant data
    - Another, is that buckling contributed to casing rupture, due to vertical loads imposed by deformation - the apparent change in the axes of ovality between the casing shear and the top of tubing, and the rotation in the apparent ovality in casing in the caliper data, suggests that possibility. Dussault discusses these failures in a 2001 paper in SPE Drilling & Completion titled "Casing Shear: Causes, Cases, Cures."
    - I note there was a large and perhaps sudden (?) release of hanger support when removing tubing, which would lead to a sudden increase in load on the tubulars, and could have triggered a stress wave that led to some additional damage, but suspect this was handled in such a way as to avoid risks of high compression causing tubing buckling.
- **Are the scenarios described properly and physically possible?**
    - yes
- **Is the evaluation of choosing the most likely scenario done properly?**
    - to the limit of the available data, yes (see above related to geomechanics and pressure monitoring of the well and reservoir(s))
    - <u>one exception is the overly simplified modeling of reservoir fill-up</u> - extent of fluid, pressure, and thermal fronts away from injectors. This was done using original porosity, an assumed Darcy porous material, and complete fill up
        - if the simple model is correct, then failure of ROW-2 could not have been triggered directly by offset injection, leaving other possibilities (normal salt movement; secondary effects of injection; leakage of fluids from the ROW-2 injection zone into the overlying one through what is assumed to be a flow barrier)
    - in contrast…
        - this is a fractured system; fluid pathways might be preferentially aligned with fractures or faults

    - porosity won’t fully recover to pre-depletion conditions, however the volumes involved are small (injected volume is less than 10% of original assumed pore volume; compaction is unlikely to decrease pore volume by more than 90%).

- **Can possible shearing of wells in the ROW field be predicted with the current dataset, monitoring and understanding**
  - risk can be estimated, if monitoring is improved (see above and below), but prediction is virtually impossible given uncertainties
  - locations of likely shearing can be predicted, however, at boundaries between materials with different properties and across fluid flow barriers; also at joints where completion properties abruptly change
  - thus, potential weak sections of the completions should be identified
- **Is the creation of dissolution caves by injecting freshwater into the ROW evaporite setting feasible. Can these contribute to casing-shear events?**
  - differential compaction due to cavity creation and collapse could lead to casing shear, however dissolution sufficient to cause large strains would require multiple reservoir volumes of fluid to pass through the zone.
  - there are no large cavities identified behind casing in the bond and other logs…
  - this risk will increase as more of the water is steam condensate
  - regardless, <u>this risk could be mitigated by adjusting the solutes in the injected water so that they are chemically compatible with formation brines and minerals</u>
- **Is the cited and other academic work supportive of theses of the Operator? This is specifically the case for the point that Anhydrite-Gypsum transition due to nearby (fresh) water injection can be ruled out as a cause or contributing factor to the shear event.**
  - I’m not qualified to comment on the geochemical processes
  - it may be that “depth” is not the limit rather it’s temperature at depth…

Monitoring

- **Is the explanation given why the casing-shear event was not noticed earlier comprehensive**
    - Tubing deformation was identified quite early in the time line; this was clearly not considered to be important; given recognition that it could be due to casing damaging the tubing, undoubtedly there will be more attention paid to this in future.
    - Certainly, failure to notice the casing-shear (tubing deformation) event was a consequence of not having the appropriate measurements at short enough time intervals, for example, tubing/annulus pressure leak / pressure isolation tests, and failure to use the data available, principally the tubing pressure loss, to trigger further investigations. Repeated tubing inspections primarily internal caliper measurements are the most straightforward way to monitor tubing deformation for obvious reasons, but require periodic operational shut-downs.
    - The risk could have been anticipated using a posteriori information about the location of the event, including the weaker tubulars (pup joints). The series of pressure and other out of spec occurrences could have led to a recognition of the risk, which would have allowed earlier shut in and testing of the conditions; instituting the appropriate corrective practices might have prevented loss of the well
    - The following incidents could have been investigated which might have led to an early work over that avoided the incident:
        - multiple tubing deformation events - why???
        - 2015 low liquid level - why???
        - 2017 and following - tubular deformation - why???
        - August 2017 - sudden pressure loss - why??? if liquid levels and surface and internal tubing pressures had been monitored
    - EP201701214429 states (in an Appendix EP201605213540) that “For all water injection wells in Twente, integrity tests (WIT’s and SIT’s25) have been carried out each year” however the results are not discussed in the Report. Did such tests show no leakage between or out of the A-annulus of all wells? Or were these suspended in 2017?
    - EP201605213540 further states “Wells ROW2, ROW4 and ROW5 have a high injectivity. In those wells the fluid level did not reach the depth of the installed BHP-gauge or BHPi more or less remained constant with increasing injection rate.”
- **Are the changes proposed to the monitoring protocol sufficient to identify casing-shear events at an earlier stage**
    - further and more repeated monitoring needs to be maintained; see above.

    - wellbore (casing) strain monitoring would be the best way to identify these events ahead of time before they cause tubing deformation.
    - daily pressure and other tests of the wells can be used to identify when events have compromised integrity, but predicting casing shear, like predicting earthquakes, is impossible other than in a statistical manner using models for how such events are triggered; see also answers above and below

- **Can other improvements to the monitoring protocol be made**
    - Operator should propose various event risks and develop a monitoring protocol to identify when each of these events is likely.
    - Wells should be monitored for annulus liquid levels and surface pressures (echo-meter acoustic methods may be appropriate for the latter), and periodically pressure tested for integrity (I infer that this was in the protocol but didn't see a systematic analysis of the results)
    - Pressure testing between the annulus and the tubular interior should be instituted
    - Reservoir pressures could be measured away from the injectors to validate models for pressure behavior of the reservoir and to track liquids; periodic pressure falloff tests could be conducted and analyzed with transducers at the reservoir
    - Fluids could be tagged, for sampling purposes, to define flow paths and identify the source of sampled fluids; this will provide hard data in the event there is a loss of integrity
    - Pressure gauges must be placed below the liquid levels (I refer to the comment "liquid level remained even below the depth at which the downhole pressure gauge was installed" in the Report
    - Injectivity tests are only useful if properly implemented - and, given uncertainties and the multi-phase nature and uncertain wet ability of the formations involved, should be replaced with interference tests or monitoring of pressure away from the injectors or between them. monitoring rates and surface pressures to ensure avoidance of excessive near-well pressure would if this is done seem to be appropriate and safe.
    - I applaud the recommendation for daily annulus pressure monitoring
    - With reference to EP201605213540, temperature logging of injectors to identify entry points of fluids (or leaks) should be run several times after shut-in, not just once, to monitor thermal recovery as a function of time.
    - Tubing ID could be monitored by caliper, to identify squeezing, and by running a stiff "pig", to check for tubing bending

- Do tubing constrictions impede flow? - step rate testing could reveal changes in tubing flow characteristics… severe restrictions could cause small pressure drops

- Follow the traffic light risk mitigation process recommended by Ellsworth

Risks

- **Is shear below the production packer indeed of low significance to continued, safe operation**

    - shear between the packer and the bottom of casing could cause deformation sufficient to trigger loss of integrity at the packer; loss of packer integrity is one of the possible causes of the breach

    - a suitable distance should be ensured between the isolation point and any potential casing deformation risk

- **Light casing specs in ROW-02 are seen as an enabling factor. Is this true or would any casing be sheared under these stresses**
    - Can shear occur if casing 7¨ 32lb/ft c75 or 9 5/8¨53,5 lb/ft c75 is used
        - I cannot evaluate this, but can say that loss of pressure integrity / operation outside design limits is to be avoided; and, data suggest that this well came close to exceeding such design limits.
        - risk assessment should be carried out by an expert in tubular design and specification; assuming loss of casing support (cement integrity) also multi-mode deformations (torque, vertical load, and shear)

- **Does the non-observance of a clay layer in the other ROW wells make casing shear in these wells very unlikely?**

    - Not <u>very</u> unlikely, but perhaps <u>less</u> likely - the juxtaposition of ductile over brittle layers leads to shear localization at the boundary, irrespective of the presence of a “weaker” layer. The weaker layer just increases the risk.

        - I note that there were tubular deformations below the failure depth that were not associated with identified clay layers

    - One other well (ROW-8) did have a slightly elevated GR just below the top of the 3C…

    - Another difference between ROW-2 and the other wells is that ROW-2 is at top of structure. Row-7A is close by; the others are on the flanks; in fact, may even penetrate the original water leg of the reservoir fluid column. If there is a gas column ROW-2 will be at the riskiest point in the structure for a seal breach or geomechanical slip or hydrofracturing event.

Appendix IV. - Figure showing locations of tubing deformations detected over the life of the ROW-2 injector

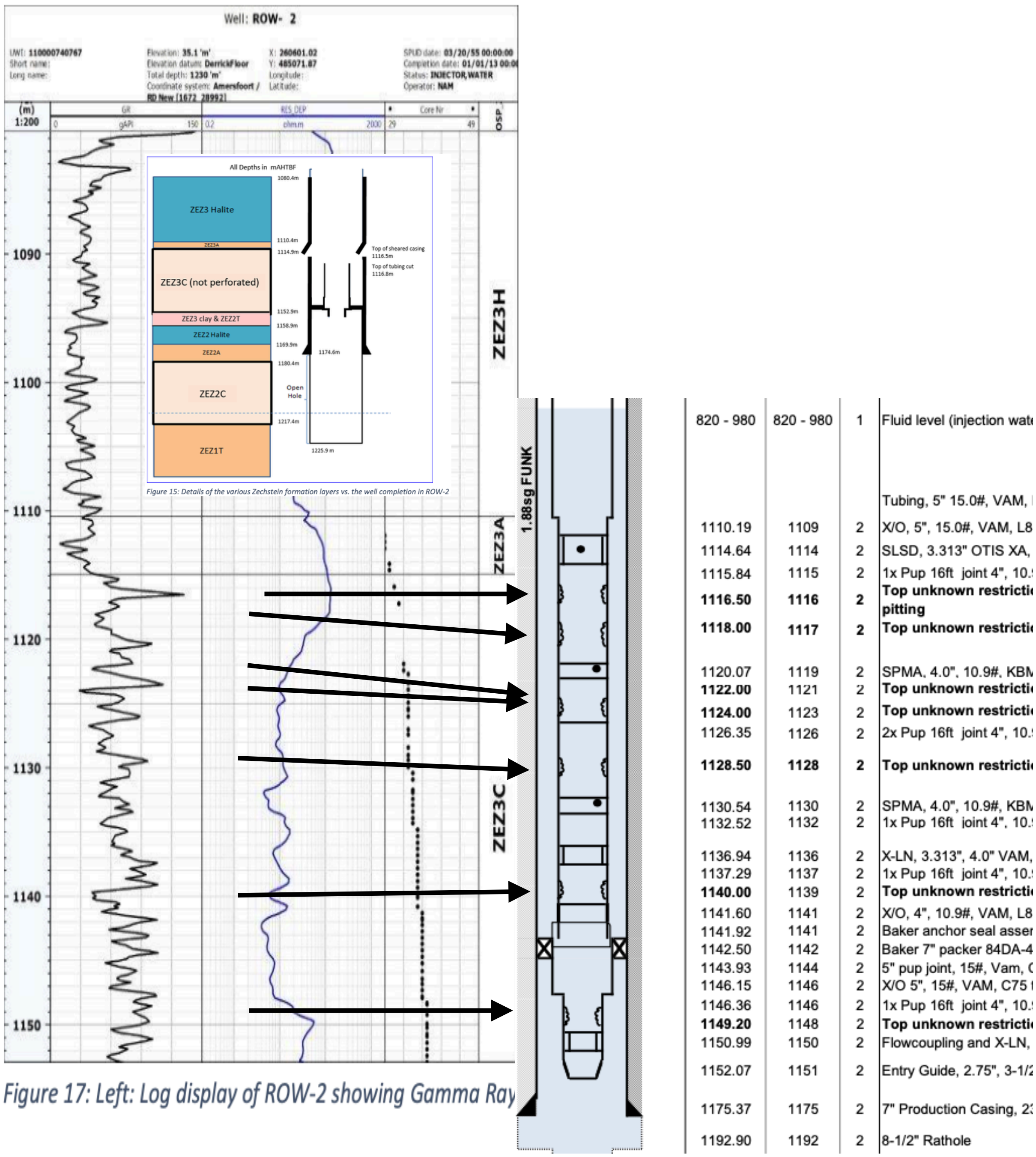

Figure 17: Left: Log display of ROW-2 showing Gamma Ray