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NAM

Nederlandse Aardolie Maatschappij

Subsidence caused by Halite dissolution due to water injection into depleted Carbonate gas reservoirs encased in Halite

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Nederlandse Publiekssamenvatting

Dit rapport beschrijft de mogelijke lange termijn bodemdaling (tussen de 8000 tot 75000 jaar) die op kan treden als steenzout (Haliet) in de diepe ondergrond gaat oplossen. Het betreft een situatie waarbij onderverzadigd zout water wordt geïnjecteerd in een kalksteen (Carbonaat) reservoir dat volledig omgeven wordt door zout (Haliet).

In de MER is uitvoerig aandacht besteed aan het mogelijk oplossen van de afdekkende steenzoutlaag indien deze laag in aanraking zou komen met het injectiewater. De MER concludeert dat deze zoutlaag niet of nauwelijks zal oplossen in het injectiewater. In het verlengde hiervan is geconcludeerd dat de gevolgen voor additionele bodemdaling te verwaarlozen zijn.

Echter om hierover aanvullende inzichten te verkrijgen is op verzoek van Staatstoezicht op de Mijnen besloten aanvullende modelleringen uit te voeren teneinde de integriteit van de afdekkende zoutlaag en de daaraan geassocieerde bodemdaling in een “meest negatieve” scenario te toetsen.

Op basis van deze uitgebreide modelleringen is aangetoond dat de conclusie uit de MER juist is en dat er geen additionele bodemdaling zal gaan optreden omdat het injectiewater bijna niet in direct contact komt met het zout, het slechts gedeeltelijk zout verzadigd wordt en het effectief rondstromen sterk belemmerd wordt.

Voor de berekeningen is een 3 dimensionaal dynamisch model gemaakt van het Tubbergen gasveld. Hierin zijn geen breuken meegenomen. Dit model is gebruikt om de lange termijn distributie (tot 1000 jaar na het stoppen van de injectie) van het injectiewater in het veld te kunnen bepalen De modelresultaten tonen aan dat, onder invloed van de zwaartekracht, het gas wat nog in het reservoir aanwezig is zich zal verzamelen in de bovenste (ondiepere) delen van het reservoir en dat het water naar de diepere delen van het reservoir zakt en zich hierbij verzamelt in de flanken van het veld.

Om het meest negatieve gevolg van zoutoplossing op bodemdaling te kunnen bepalen zijn de geologisch meest extreme situaties (zgn. worst-case scenario) aangenomen. Er is aangenomen dat het injectiewater uitsluitend in het bovenste van de twee reservoirs geinjecteerd wordt, dat de boven en onderkant van het reservoir overal in direct contact is met het Haliet en dat het water uiteindelijk volledig zout verzadigd wordt. Op basis van deze drie extreme condities is door middel van een geomechanisch model een bodemdalingsprofiel berekend. De uitkomst van dit zeer onwaarschijnlijke scenario is dat mogelijk na een periode 8000 tot 75000 jaar aan het oppervlak een geleidelijke komvormige verzakking optreedt met een diameter van ongeveer 5 kilometer en die op zijn diepste punt een diepte heeft van ca. 12-14 cm. Hierin zijn variaties in de verdeling van het geïnjecteerde water in het reservoir meegenomen (van geheel geconcentreerd in het centrum tot gedistribueerd over de flanken). Het diepste punt ligt midden boven het veld. De totale hoeveelheid steenzout die hierbij opgelost wordt is minder dan 0.5% van het totale volume van de zoutlaag boven het ondiepste reservoir. Op basis daarvan kan gesteld worden dat zelfs in dit extreme scenario de integriteit van de afdekkende zoutlaag volledig gegarandeerd kan worden.

In werkelijkheid is de verwachting dat er totaal geen additionele bodemdaling zal gaan optreden (conform de het Water Management Plan dat onderdeel is van de vergunningen). Er zijn 3 redenen waarom bovengenoemde extreme situatie niet zal gaan optreden:

[1] In het model is aangenomen dat er een direct contact is tussen het Carbonaat reservoir en de over- en onderliggende steenzout lagen. In werkelijkheid is dit niet het geval. Het Carbonaat reservoir heeft overal aan de onder en bovenkant een Anhydrietlaag, die niet oplosbaar is en derhalve direct contact tussen injectie water en het Haliet tegen gaat. Alleen in de buurt van breuken kan het Carbonaat direct in contact staan met het Haliet. In werkelijkheid is het contact oppervlak dus vele malen kleiner dan aangenomen wordt in het model en zal de totale hoeveelheid zout die op kan lossen sterk beperkt worden.

[2]. In de modellering is aangenomen dat het geïnjecteerde water volledig zout verzadigd wordt. In werkelijkheid is dit niet het geval. Het water dat van oorsprong in de gas reservoirs in Twente zit is zelfs na de vele miljoenen jaren dat het opgesloten heeft gezeten niet volledig zout verzadigd (zoutconcentratie van het water in de Tubbergen en Rossum-Weerselo velden

is 210 tot 270 gram/liter, terwijl onder de condities in de ondergrond volledig verzadigd zout water een concentratie van 300 tot 320 gram/liter zou hebben).

[3] Het geïnjecteerde water moet kunnen rondstromen in het reservoir om er voor te zorgen dat maximale zoutoplossing op kan treden (onverzadigd water moet naar het grensvlak met het zout kunnen stromen terwijl verzadigd water weg moet kunnen stromen). De mate waarin dit rondstromen kan optreden (convectie cellen) is sterk afhankelijk van de verhouding tussen de horizontale en vertikale doorlaatbaarheid (permeabiliteit) van het gesteente (Kv/Kh). In het model is een verhouding van 10^{-2} aangenomen (de vertikale permeabiliteit is 100 keer kleiner dan de horizontale permeabiliteit). Op basis van geologisch inzicht is het echter veel waarschijnlijker dat deze verhouding tussen de 10^{-3} en 10^{-4} ligt wat inhoudt dat het ronstromen in werkelijkheid waarschijnlijk veel trager gaat dan in het basis model . In een reservoir van ongeveer 50 m dikte (zoals in Tubbergen) met een Kv/Kh van 10^{-3}, waarbij aangenomen wordt dat het water in volledig contact staat met het Haliet, geeft de modellering aan dat het bijna 8000 jaar duurt voordat een convectie cel gevormd kan worden. Deze modellering laat bovendien zien dat het injectiewater slechts tot een concentratie van 150 gram/liter zout verzadigd wordt. Voor een Kv/Kh van 10^{-4} geeft de modellering aan dat het vormen van zo'n convectiecel zelfs 75000 jaar duurt.

Geconcludeerd kan worden dat in het meest extreme geval op een termijn van 8000 tot 75000 jaar een maximale bodemdaling van ca. 12 tot 14 cm zou kunnen optreden als gevolg van zout oplossing door injectiewater in de oude gasvelden. Hierbij wordt dan 0.5% van het totale volume van de zoutlaag boven het reservoir opgelost, wat inhoudt dat zelfs in dit extreme scenario de integriteit van de afdekkende zoutlaag gegarandeerd kan blijven worden.

In werkelijkheid (en conform het Waterinjectie Management Plan) wordt niet waarschijnlijk geacht dat er additionele bodemdaling zal gaan optreden omdat het injectiewater bijna niet in direct contact komt met het zout, het slechts gedeeltelijk zout verzadigd wordt en het effectief rondstromen van injectiewater sterk belemmerd wordt.

1. Summary

This report describes the impact of Halite dissolution on potential subsidence for the case of low saline water injection into depleted Carbonate gas fields encased in Halite. This was investigated to assess the possible impact of low saline Schoonebeek Oilfield production water injection into the Tubbergen and Rossum Weerselo depleted gas fields which have above described geological setting.

In the original Environmental Impact Assessment, a lot of attention was dedicated to the risk of degrading cap rock integrity through salt dissolution. The EIA concluded that this risk is very low. This was supported by the subsidence calculations done as part of the granted Water Management permits. These indicate that no additional subsidence is to be expected in the base case situation. Nevertheless, the Dutch regulator (State Supervision of Mines) requested to do a further and more detailed study into the risk and determine the worst case subsidence and caprock integrity reduction that could occur.

A simplified (un-faulted) full-field dynamic model was made for the Tubbergen field. This model was used to assess the distribution of the injection water long after injection has been stopped. Modelling results show that due to gravity segregation, the remaining gas will collect in the crest of the field and the injection water collects in the down-dip flanks of the reservoir. In order to determine a worst case subsidence scenario, the under-saturated injection water is assumed to be in direct contact with the halite over- and underlying the carbonate reservoir. Furthermore it is assumed that over time the injection water will become fully salt saturated by dissolving the surrounding Halite. A geomechanical model was used to determine the ultimate subsidence bowl caused by this Halite dissolution. Modelling results show that in the very worst case after a period of 8000 to 75000 years a subsidence bowl with a diameter of about 5 km and a maximum depth of 12-14 cm could be formed. This includes sensitivities on the possible distribution of water in the injection reservoir (from fully concentrated in the centre of the field to distributed over the flank regions). The deepest point is expected to be located above the crest of the injection reservoir. The total volume of halite that is dissolved in this case is less than 0.5% of the total halite volume in the layers overlying the carbonate reservoir. Even in this extreme case integrity risks of the halite top seal are deemed to be extremely low.

To arrive at a worst case impact assessment and tests the extremes of the possible salt caprock integrity, the assumptions for this modelling study were on purpose very conservative as explained below.

1. In the un-faulted model it was assumed that there is everywhere a direct contact between the injection reservoir and the over- and underlying Halite sequence. In reality this is not the case as the carbonate injection horizons are over- and underlain by regional anhydrite layers which form a continuous, impermeable and insoluble separation between the injection reservoir and the Halite rock (Ref 1). Only in faulted areas it is possible that Halite is in contact with the injection reservoir. The actual effective contact area is therefore very restricted and consequently Halite dissolution will be severely restricted (Ref 2)

2. In the modelling it was assumed that all injected water becomes fully salt saturated. In reality this is not expected given that even the original formation water in the gas reservoirs was not salt saturated (NaCl concentration of Tubbergen/Rossum-Weerselo formation water is 210,000/270,000 ppm whilst fully saturated brine contains 300,000-320,000ppm at reservoir conditions – a 15% to 50% overestimate of the dissolution capability)

3. In order to facilitate salt dissolution, undersaturated water needs to be able to flow towards the reservoir-salt interface and saturated water needs to be able to flow away from that interface. The extent to which such convection cells can be formed critically depends on the Kv/Kh ratio in the carbonate reservoir. In base case the full field dynamic model a Kv/Kh ratio of 10^{-2} was assumed. A geological review has shown that this ratio is more likely to be in the order of 10^{-3} to 10^{-4}. A lower ratio results in a much slower vertical flow within the injection reservoir. In a reservoir of 50m thickness (like Tubbergen) and a Kv/Kh of 10^{-3} it takes almost 8000 years for a convection cell to be formed. For a Kv/Kh of 10^{-4} this is even close to 75,000 years (Ref 2).

The base case assumption for additional subsidence to be caused by water injection in the Twente fields subsidence is expected to be negligible (ref the Water Management Plan). This negligible impact is due to 3 key parameters:

1. Due to the presence of insoluble and impermeable anhydrite layers between the carbonate reservoirs and the halite, the under saturated injection water may only have a very limited contact area with the halite
2. The injection water is not expected to become fully salt saturated
3. The possibility to create effective convection cells is severely hampered by the low Kv/Kh.

In the worst case scenario modelled, where the above 3 constraints have essentially been ignored and all of the water is assumed to only be injected in the upper of the two reservoirs, the impact of Halite dissolution may result in a maximum additional subsidence of 12-14 cm only. This only represents a reduction of 0.5% of the average thickness of the halite overlying the upper (ZEZ3C) Carbonate injection reservoir, implying that even in this extreme case the cap rock integrity will remain guaranteed.

2. Geology and Modelling assumptions

2.1 Introduction

NAM is currently injecting produced low saline water from the Schoonebeek Oilfield into depleted gas fields in Twente. Some of these gas fields (Tubbergen and Rossum-Weerselo) have Carbonate injection reservoirs in between Halites originating from the Zechstein evaporation cycles.

When performing the above described low saline water injection there is a potential risk is that some of the Halite may be dissolved by the injected, low saline water, and this Halite dissolution could result in subsidence. In the original Environmental Impact Assessment, a lot of attention was dedicated to the risk of degrading cap rock integrity through salt dissolution. The EIA concluded that this risk is very low. This was supported by the subsidence calculations done as part of the granted Water Management permits. These indicate that no additional subsidence is to be expected in the base case situation. Nevertheless, the Dutch regulator (State Supervision of Mines) requested to do a further and more detailed study into the risk and determine the worst case subsidence and caprock integrity reduction that could occur.

This report describes a study in which the worst case impact of this dissolution on potential subsidence and cap rock integrity has been assessed.

The subsidence has been predicted by modelling the ultimate water injection distribution across the injection reservoir using a full-field dynamic model. To achieve this, the model was run sufficiently long to ensure that vertical equilibrium between gas and injected water has been established (i.e. for a period of 1000years). The water is then assumed to be in direct contact with the surrounding Halite. Further it is assumed that over time the injected water will be able to become fully salt saturated by dissolving the surrounding Halite. A geomechanical model (GeoMec) was then used to determine the ultimate subsidence bowl caused by this Halite dissolution.

In order to estimate potential subsidence resulting from Halite dissolution, certain assumptions had to be made. These assumptions are conservative, i.e. the predicted potential subsidence is an ultimate worst case or even an overprediction. In order to understand the conservatism of the assumptions made, the geology and dissolution mechanism needs to be understood, which will be discussed in this chapter. Subsequently the dynamic full-field reservoir (MORES) model and geomechanical (GeoMec) model set-up will be discussed.

2.2 Geology

A geological review of the Tubbergen (TUB) and Rossum-Weerselo (ROW) injection reservoirs has been performed [Ref 1]. In this section, some of the key conclusions from this review will be repeated.

In the TUB and ROW fields the injection reservoirs are the ZEZ2C and ZEZ3C Carbonate layers in the Zechstein formation and the DC sandstone in the underlying Limburg formation. The Carbonate injection layers in these fields have an Anhydrite/Halite top and base seal whereas the seal of the DC sandstone is formed by intra Carboniferous shales and base Zechstein Anhydrites (Werra Anhydrite). Subsidence modelling by Halite dissolution therefore has been focussed on the Carbonate injection reservoirs.

The Zechstein in the TUB and ROW fields consist of the 4 evaporitic cycles as these are known to exist in the Southern Permian Basin (i.e. deposition in each cycle consisting of a sequence of Clay-Carbonates-Anhydrites-Salts and Halites/Anhydrites), whereby the 4th cycle may not be developed fully (mainly only Halites developed). Gas has been produced from the Carbonates in the 2nd and 3rd cycle, also called ZEZ2C and ZEZ3C, and upon depletion of these reservoirs, the ROW and TUB gas production wells were converted into water injectors, and water is being injected in the ZEZ2C and ZEZ3C Carbonates [Ref 3]

The Z2 and Z3 reservoirs are, in general, fairly conformal and separated by uniformly thick halite and anhydrite layers. These anhydrite layers are highly correlative between the TUB and ROW wells and are known to be developed regionally and hence to be continuously present across the TUB and ROW fields.

The ZEZ2C and ZEZ3C Carbonates are, in general, characterized by dolomitic layers interspersed by Anhydrites. In the ZEZ3C Carbonates these dolomitic layers are typically 20-30 cm thick whereas the interspersed Anhydrites range in thickness from cm to dm. In the ZEZ2C Carbonates the dolomitic and interspersed anhydritic layers are thicker (both 4-5m).

In both ZEZ2 and ZEZ3 Carbonate reservoirs, the main permeability is provided by the presence of open natural fractures. Core material shows that the fractures are present in the clean carbonates (Dolomites) and are absent (abut) as soon as an Anhydrite or anhydritic layer is present. The presence of interspersed anhydritic layers within the Carbonate reservoirs therefore means that the fracture networks are laterally quite extensive but vertically limited. This fracture distribution heavily dictates the effective permeability and Kv/Kh on a reservoir scale. The conducted geological review [ref.1] concluded that the Kv/Kh ranges from 0.005 for an un-faulted area to 0.0001 to areas, affected by fault associated fractures.

2.3 Halite dissolution mechanism

An un-faulted full-field model is used to predict the distribution of the injected water across the entire reservoir after vertical equilibrium has been reached. It is then assumed that all this water is in full contact with the surrounding Halite causing injection water at the Carbonate/Halite interface to dissolve halite. Convection cells are then assumed to redistribute the dissolved halite. Herewith gravitational forces will force relatively heavy saturated brine to flow down into the Carbonate layer whilst lighter less saline injection water will rise towards the Halite/Carbonate interface. As this is a gravity driven process, these convective fluid flows are predominantly vertical. This means that the dissolution power at each point at the Halite/Carbonate interface can be determined by calculating the volume of injection water inside the Carbonate layer underneath this point. Herewith it is assumed that ultimately all injected water will become fully salt saturated (i.e. 7m^3 water will dissolve 1m^3 Halite).

Note, the assumption that all water fully contacts the overlying Halite formation over time is an extremely conservative representation of the actual geology of the injection reservoirs, in view of the regionally present Anhydrites above and below the Carbonate layers, as explained in Section 2.1 [Ref 1]. Contact between the Carbonate and Halite layers can only occur at faults with sufficient offset to juxtapose Halite against Carbonate. However, it would be numerically too time consuming to model such an actual geological configuration on a full-field scale, i.e. model halite dissolution in a faulted full-field model. In order to arrive at a subsidence prediction therefore the simplified conservative assumption has been made that all injected water fully contacts the Halite. As described above, this assumption will lead to a gross over prediction of the total amount of Halite dissolution and therewith also an over prediction of the amount of subsidence. The subsidence prediction made in this study will therefore represent an unrealistic, ultimate worst case scenario.

Further it should be noted that the formation waters, originally present in the Zechstein Carbonate reservoirs in TUB and ROW are <u>not</u> salt saturated. The NaCl concentration in TUB formation water is 210,000ppm and in ROW 270,000ppm whereas at saturated conditions a NaCl concentration of 300,000-320,000ppm is expected. The assumption that all injected water will become salt saturated is therefore also very conservative (a 15% to 50% overestimate) and, in fact, unrealistic.

Finally, it also should be noted that convection cells, as a result of formation water density contrasts, take a significantly long time to develop in low Kv/Kh Carbonate reservoirs. A separate reservoir modelling study [Ref 2] shows that it takes almost 8000 years for a convection cell inside a 50m thick Carbonate cell with $Kv/Kh=10^{-3}$ to saturate the water inside the cell from zero to 150,000ppm NaCl concentration (note, fully salt saturated water contains 320,000ppm NaCl concentration). For a Kv/Kh of 10^{-4} this is even close to 75,000years.

2.4 Dynamic reservoir model

A static geological model of the Tubbergen field was used to create an upscaled dynamic model that includes the stratigraphy as summarised in Table 2.1. Figure 2.1 displays output, generated with the Shell in-house simulator GeoMec, in which the stratigraphy is graphically shown.

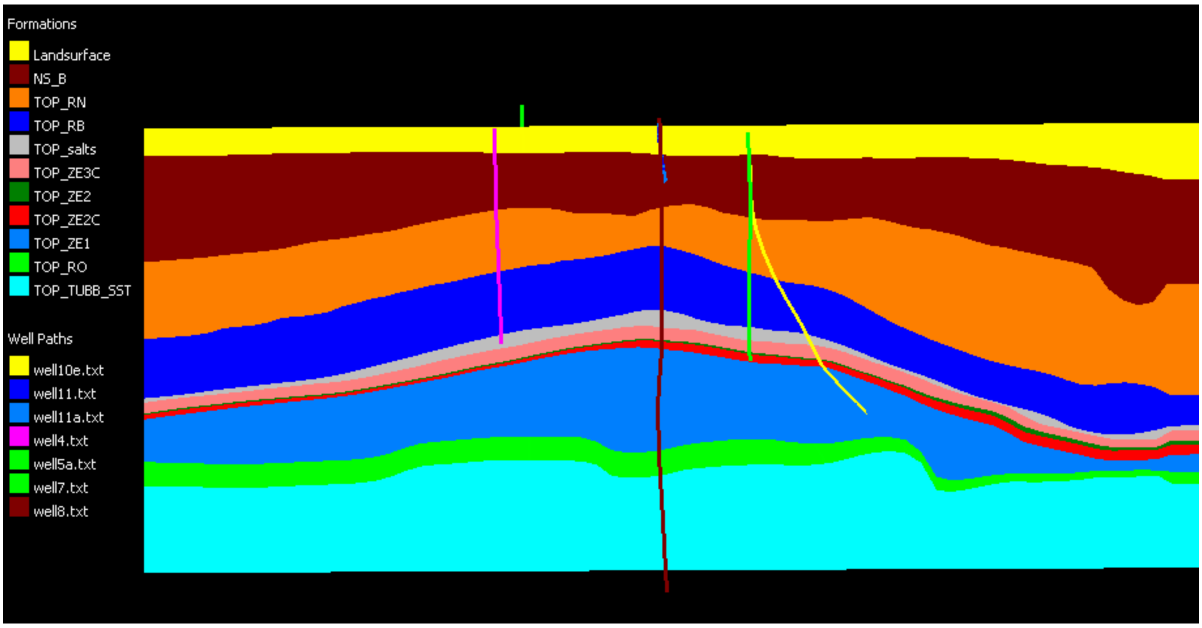

Figure 2.1: Geology of the Tubbergen static model (as Geomec mesh cross section) used to construct the dynamic Dynamo-MoReS simulation model and. Formations of interest include the Zechstein 3 Halite (TOP_salts: grey), the Zechsteain 3 Carbonate (TOP_ZE3C: pink), the Zechstein 2 Halite (contained within the TOP_ZE2 interval along with ZEZ2 Anhydrite and ZEZ3 Grey Salt Clay: dark green), and the Zechstein 2 Carbonate (TOP_ZEZ2C: red).

It is important to realise that the layering in the model does not include all the anhydrite layers, which shield off the Carbonate reservoirs from the over- and underlying Halite formations. However, since the objective of the dynamic model is to predict the ultimate injected water distribution across the reservoir and not to directly model halite dissolution, this stratigraphic definition is considered sufficient.

Also, it is highlighted that the model used does not contain faults. In reality the injection reservoirs do contain faults. These faults however are not expected to sufficiently hamper water flowing towards the down dip flanks of the reservoir. The injection water distribution achieved with the un-faulted model is therefore considered to be sufficiently realistic for the time range considered (1000years).

Table 2.1: Formations and associated Dynamo-MoReS ZONEID identifiers used in the dynamic full-field model. Note that the full Zechstein 1 formation thickness is not included in the model.

Formation Number	Formation Name	MoReS ZONEID	Average Interval Thickness (m)
1	Zechstein 3 Halite	4	65.3
2	Zechstein 3 Carbonate	5	68.9
3	Zechstein 3 Grey Salt Clay	6 - 7	9.1 + 4.6
4	Zechstein 2 Roof Anhydrite		
5	Zechstein 2 Halite		
6	Zechstein 2 Carbonate	8	39.4
7	Zechstein 1	9	50 (truncated)

In the modelling the Zechstein carbonate matrix porosity was assumed to be 0.03, the horizontal effective permeability 177 mD, and a Kv/Kh ratio of 10^{-2}. A geological review, which was performed in parallel to this study, has shown that the Kv/Kh ratio is more likely in the range 10^{-3} to 10^{-4} (this Kv/Kh reflects the impact of the thin Anhydrite beds which are interspersed in the Carbonate reservoir). A lower vertical communication will significantly slow down any halite dissolution at the top of the injection reservoir. The assumption that all water will become fully salt saturated is therefore less likely at the more realistic lower Kv/Kh ratios. Also at low Kv/Kh ratio's the water is expected to slower collect at the down-dip flanks of the reservoir therewith avoiding local halite dissolution at these flanks. Assuming a Kv/Kh of 10^{-2} is therefore a very conservative assumption.

Table 2.2, Summary of Corey-model parameters used to calculate relative permeabilities as a function of water saturation.

Relative Permeability Corey-Model Parameter	Primary Drainage	Secondary Imbibition
Connate Water Saturation (S_{wc})	0.25	na
Residual Gas Saturation (S_{gr})	na	0.15
Gas end-point relative permeability (at S_{wc})	0.9	0.9
Water end-point relative permeability (at S_{gr})	na	0.5
Gas Corey exponent (n_g)	2	3
Water Corey Exponent (n_w)	4	4

The saturation curves are described in Table 2.2 and shown in Figure 2.2. These curves are based on previous work as is described in the water injection FDP [ref.4] and a water disposal study, performed by Horizon Energy Partners in 2004 [ref.5].

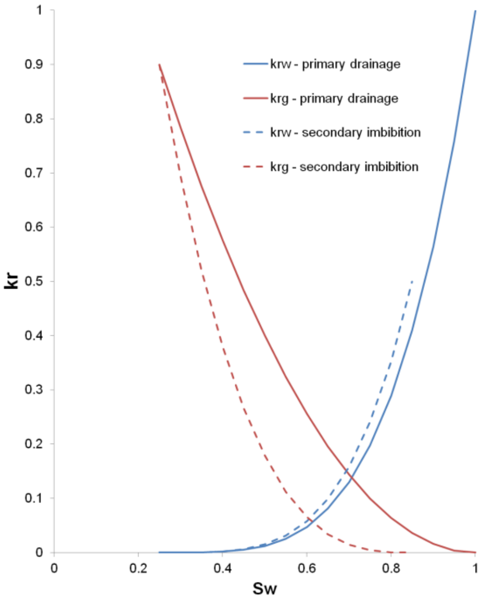

Figure 2.2: Corey-Model primary drainage and secondary imbibition relative permeability curves used in this study (input parameters are summarised in Table 2.2).

The dynamic simulator was used to model a case where 4000m^3/d, the planned daily injection rate into the Tubbergen field, was injected over a period of 20 years. All of the water was injected into the Zechstein 3 Carbonate as this represents a worst case where the capacity to dissolve halite is not split between formations.

2.5 Geomechanical modelling

A field-wide halite dissolution profile can be made using the ultimate water distribution, predicted from the dynamic reservoir model as described in section 2.4, and the halite dissolution assumptions as described in section 2.3. This halite dissolution profile is then converted into a salt dissolution strain, which is an input into a Finite Element Model in order to determine the resulting subsidence. In the following sub-sections further explanation is given on the salt dissolution strain calculation and the Finite Element Modelling.

2.5.1 Salt dissolution strain

In this study the (very) conservative assumption has been made that all injected water will become fully salt saturated. In case also the conservative assumption is made that the injection water has no initial salt content, then 7 m^3 of injection water are is required to dissolve 1 m^3 of Halite.

As discussed in section 2.3, density driven convection cells are assumed to redistribute the dissolved halite predominantly vertically. The amount of dissolved salt per square meter Carbonate/Halite interface is therefore dependent on the amount of cubic meters of fresh injection water below this square meter interface. In other words, the salt dissolution capacity V_d per m^2 Carbonate/Halite interface V_d is (1/7) of the amount of injection water V_w in the carbonate underneath.

When calculating V_w it should be noted that some of the pore space is already occupied by salt water and some of the pore space will remain gas-filled. The fraction of injection water occupying the pore space at each point in the reservoir can be determined from the ultimate water saturation S_w (i.e. after vertical equilibrium has been reached in the dynamic reservoir simulator) minus the original water saturation $S_{w,0}$ at that reservoir location. V_w is then calculated as the Carbonate reservoir height H_c times the average porosity ϕ, multiplied by the change in water saturation (S_w-$S_{w,0}$). Based on this V_d then can be calculated as follows:

$$V_d = {}^1\!/_7\,\phi H_c \left(S_w - S_{w,0}\right) \qquad (1)$$

The salt dissolution strain ε_d, using Halite layer thickness H_s rather than volumes (dissolved salt / in place salt) is hence:

$$\varepsilon_d = \frac{V_d}{V_s} = {}^1\!/_7\,\phi \frac{H_c}{H_s}\left(S_w - S_{w,0}\right) \qquad (2)$$

Since Geomec presently has no easy way of operating ratio's on thicknesses of layers, the strain was not assigned to the rock salt, but to the top carbonate, rendering the same volume of "contraction", hence to almost the same subsidence (given the almost identical depth).

$$\varepsilon_d = \frac{V_d}{V_s} = {}^1\!/_7\,\phi\left(S_w - S_{w,0}\right) \qquad (3)$$

The porosity of the carbonates in the reservoir simulator and the Geomec model has been set at 3%, which is an average of the matrix and fracture porosities. A different porosity assumption would also give a different water distribution, hence they are related.

2.5.2 Finite Element Modelling

In order to investigate the salt dissolution effects on potential subsidence, a Finite Element Model was built. It was created using the Shell in-house simulator Geomec, running on TNO-Diana Finite Elements. Formation surfaces were exported as pointsets from a Petrel model, available at NAM offices. Given the crestal structure without large fault throws, a Hexahedron Model (8 nodal brick elements) was built from the surfaces. The lateral grid was taken as 100 m × 100 m and the vertical element dimension varies with the layer thickness.

Material properties (like laboratory data on core), to be used as input parameters for the geomechanical modelling, were not present or not retrieved, given the age of the field. Appendix 1 provides more information on the applied values, basically estimated from global trends.

Figure 2.3 shows a double cross section of the Geomec mesh, showing the field's crestal structure. Figure 2.4 is a zoom in on the (gas) reservoir part of the field, showing the two reservoirs below a salt cap. The injection reservoirs are annotated by TOP_ZE2C and TOP_ZE3C.

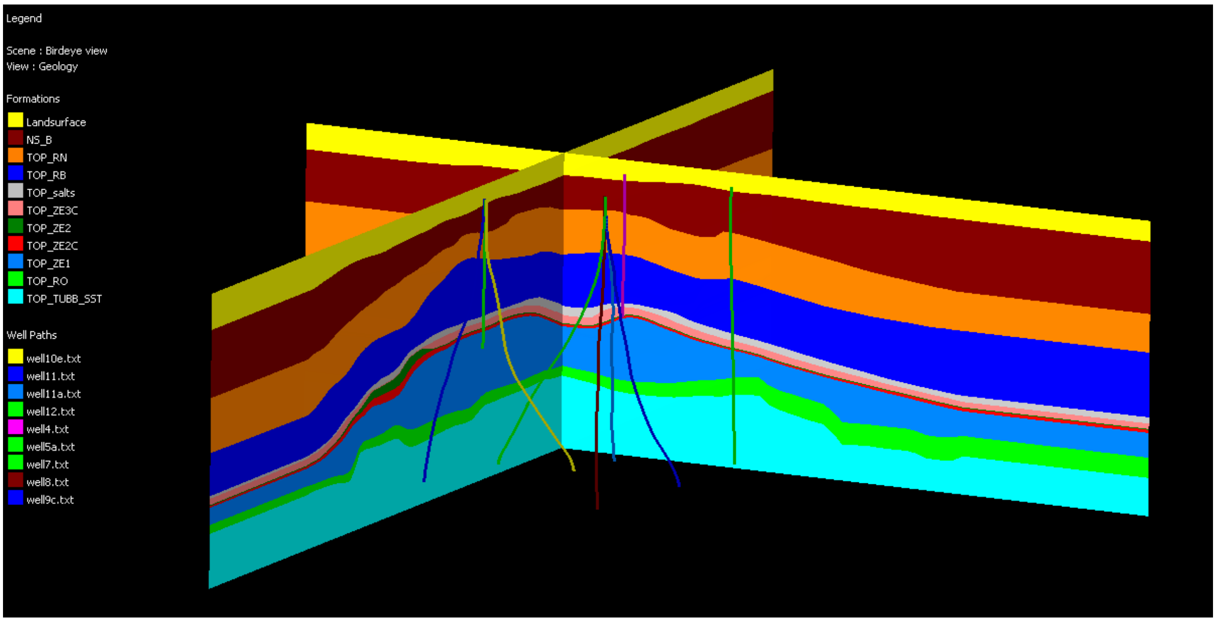

Figure 2.3: Geology of the Tubbergen static model (as Geomec mesh cross section) given two cross sections and some wells, some crossing the reservoirs.

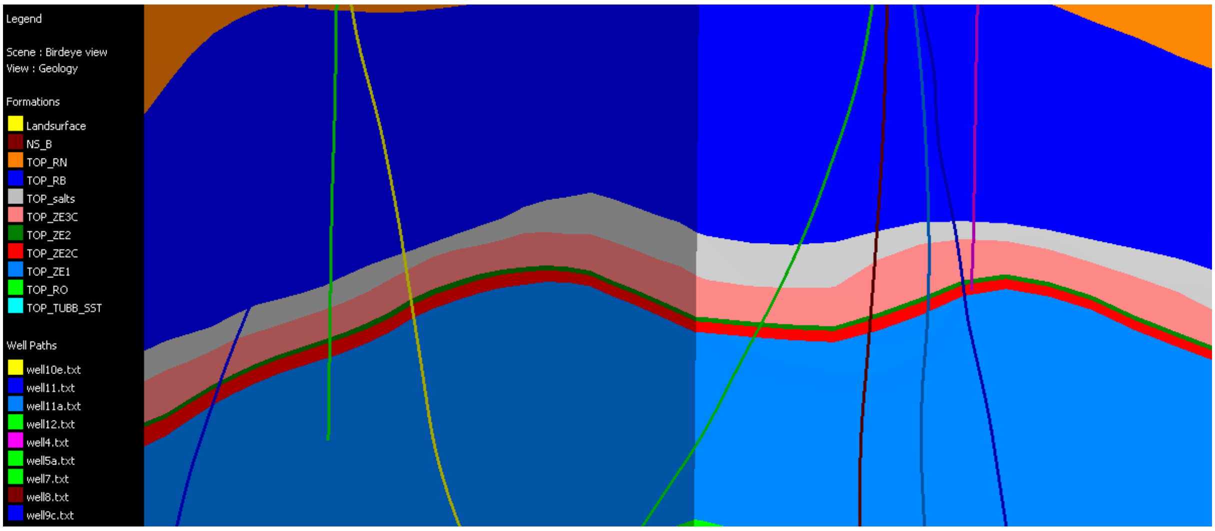

Figure 2.4: Zoom in on cross sections with crestal properties of layer thicknesses. The grey layers is the top salt cap. The pink and red layers are the carbonate reservoirs ZE(Z)3C and ZE(Z)2C

Figure 2.5 shows an impression of the Finite Element Mesh, visualised for the reservoirs and the under burden.

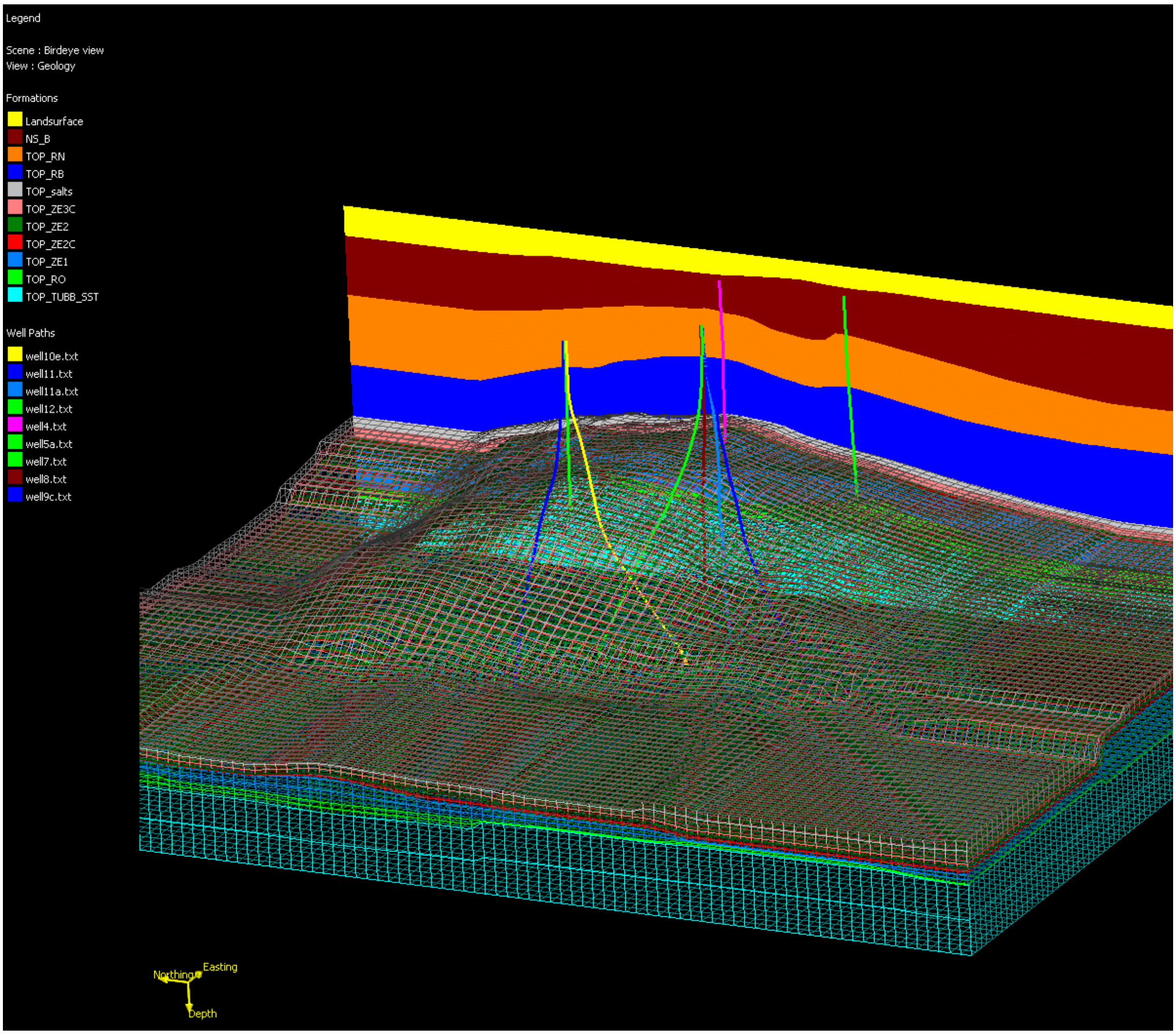

Figure 2.5: Cross section and partial mesh (salt, carbonates and underburden) with some wells for orientation. The surface (lateral) mesh is 100x100 m. The vertical size of the elements varies per location (depending on layer thickness).

3. Results

3.1 Dynamic reservoir modelling results: injected water distribution

The dynamic reservoir model, as described in section 2.4, was used to model the distribution of injection water for the case where 4000m^3/d water, which is the planned Tubbergen injection rate, was injected into the ZEZ3C formation over a period of 20years. The resulting injected water distributions as a function of time are given in figure 3.1.

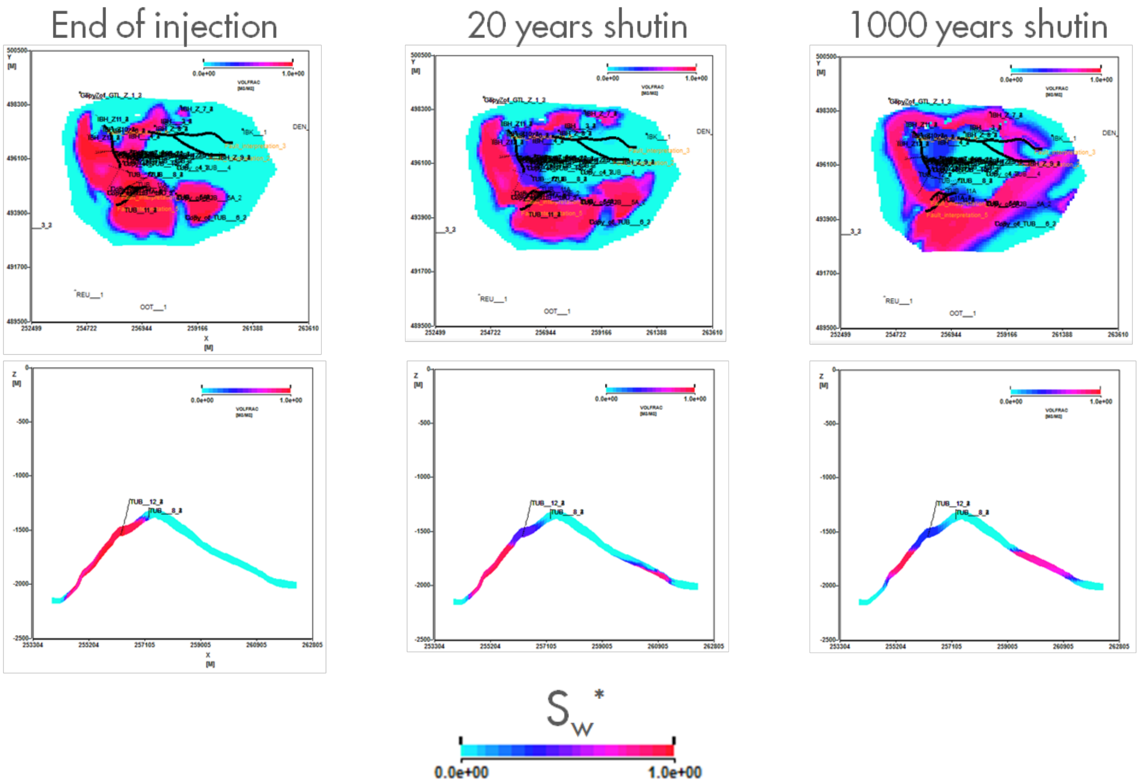

Figure 3.1: XY and XZ slices through the full field model showing the fresh water fraction of the total water saturation (S_w^*) distribution after 20 years (end of injection), 40 years (20 years shut in), and 1020 years (1000 years shut in). S_w^* is defined as the water saturation multiplied by the injection water tracer concentration.

Figure 3.1 shows a rapid gravity segregation of the injection water. The more buoyant natural gas occupies the crest of the structure with injection water moving down the flanks. Vertical equilibrium is (nearly) completely achieved after 1000 years shut-in, and in fact the distribution after 20 years shut-in is already not too far away from the final (1000 year shut-in) distribution. The conclusion is that relatively rapidly after shut-in, the injected water stops flowing.

As described in section 2.3 the distributed injected water is conservatively assumed to be in full contact with the overlying Halite. Another conservative assumption was that this full contact causes the injected water to become fully salt saturated. The resulting Halite dissolution was subsequently converted into a dissolution or shrinkage strain εd as explained in section 2.5.1. This strain was then used as input into a geomechanical model to estimate a potential worst case subsidence bowl. The next section will show the geomechanical modelling results.

3.2 Geomechanical modelling results

The ZEZ3C layer was loaded with a “shrinkage” strain, as explained in sections 2.5.1 and 3.1. The saturation changes were taken from MoReS as a pointset, as depicted in Figure 3.2. Black areas are areas with void cells (no results) where Geomec assumes the saturation changes are zero.

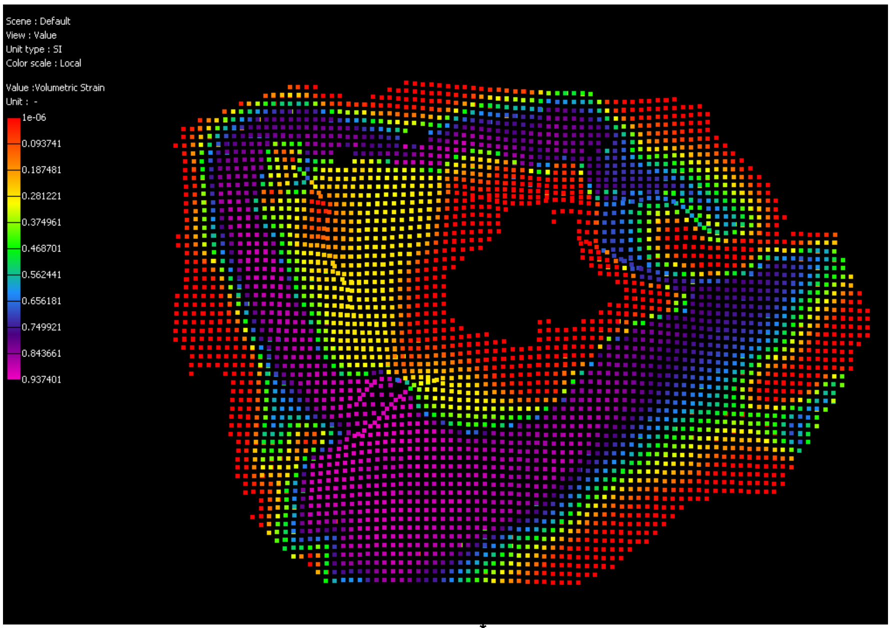

Figure 3.2: Total water saturation change (S_w^*) distribution after 1000 years shut in, usued to predict salt dissolution. The purple area is the area of fresh water injection. In the middle, there is still a high gas saturation and at the edges, the water (brine) saturation was initially high.

The salt dissolution shrinkage was computed from the saturation changes by computing:

$$\varepsilon_d = \tfrac{1}{7}0.03\left(S_w - S_{w,0}\right) \quad \textbf{(4)}$$

These shrinkage strains have been assigned to the ZEZ3C layer as loading. The Carbonates have been given a high Poisson’s ratio to prevent the volume from being stored in the carbonates. Since we are not looking for non-linear behaviour in the carbonates (or proper lateral stress build-up), this is a valid approach to load the system with “salt convergence”.

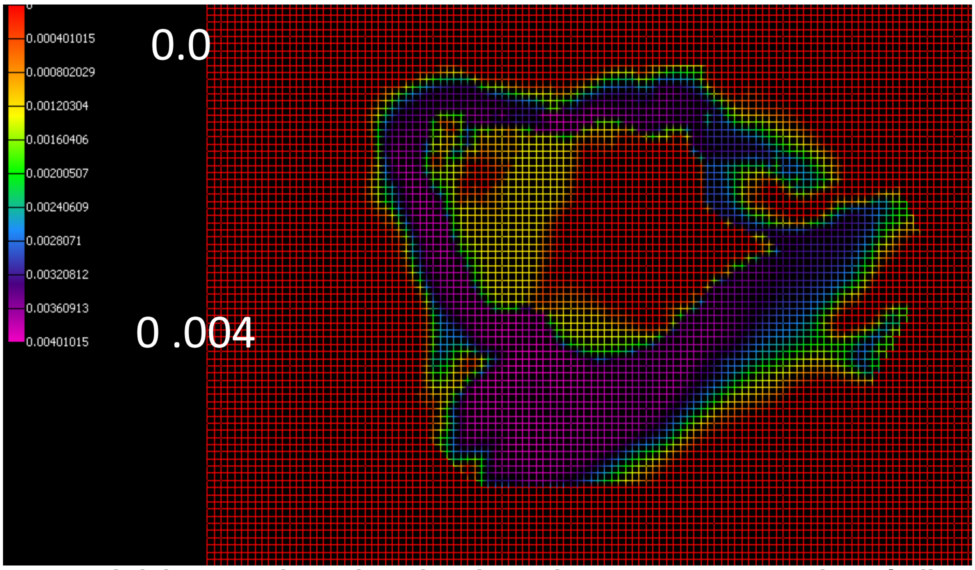

Figure 3.3: Shrinkage strain assigned to the carbonate to represent the salt dissolution volume.

The worst case subsidence bowl, as the result of the shrinkage strain loading results a maximum of some 12 cm in the centre. The total volume of the bowl (calculated by summing the product of subsidence and cell area over the full mesh in Excel) is some 4 MMm^3, roughly $(1/7)^{th}$ of the 30 MMm^3 water injection and roughly equal to the total expected salt dissolution.

When distributing the 4 MMm^3 halite dissolution across the area of shrinkage strain as per Figure 3.3 (16 km^2) then the average halite thickness that is dissolved is 0.25 m. This is less than 0.5% of the average Halite thickness above the Carbonate injection reservoirs (127 m for the Tubbergen field and 67 m for the Rossum-Weerselo field).

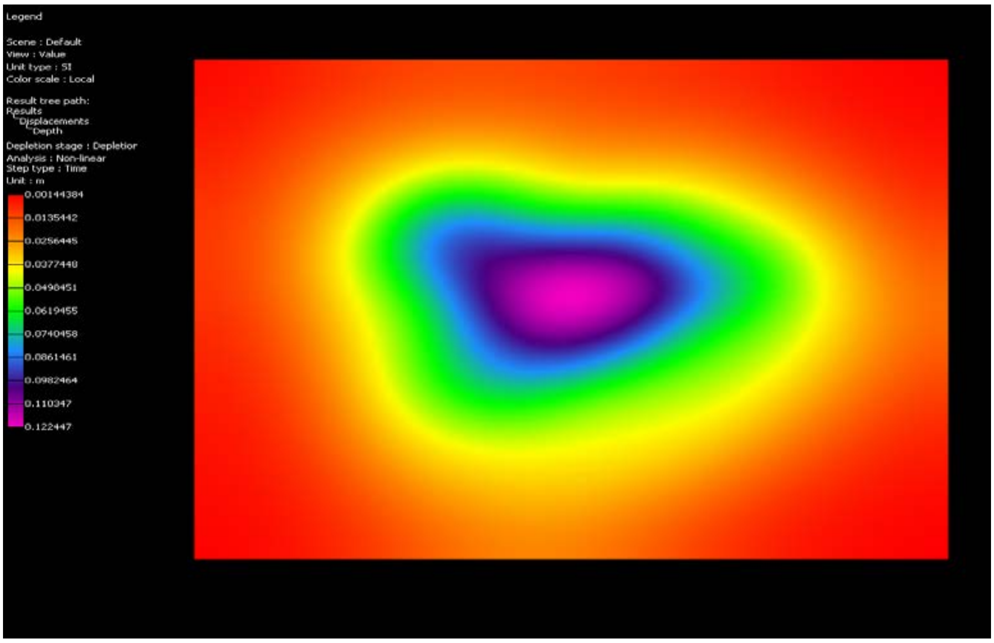

Figure 3.4: Subsidence bowl (0-12 cm) resulting from salt dissolution and salt creep leaving zero brine volume in the salt.

As sensitivity also a fully different water injection and salt dissolution was taken, concentrating in one part, but resulting in the same 4 Mm^3 of salt dissolution, see Figure 3.5. This could be possible if both the ZEZ2C and ZEZ3C take water and distribution to the flanks is somehow limited and the porosity is higher (6%) to take all the water. In this case the contraction strain almost increases a factor of 4, but on a much more limited area.

The subsidence is slightly higher, as was to be expected from concentrating the contraction to a limited area. The maximum subsidence increases from 12 cm to 14 cm in a more confined bowl, see Figure 3.6.

Other sensitivities have been run, like stiffness parameters of the overburden, but all give a similar picture. The largest uncertainties are:

- Distribution of the fresh water (also in time)
- Speed of dissolution (convection cell effectiveness and dissolution baffles like anhydrite layers)
- Injection water picking up salt, which is present within the Carbonate layers (this limits any dissolution of overlying Halite)

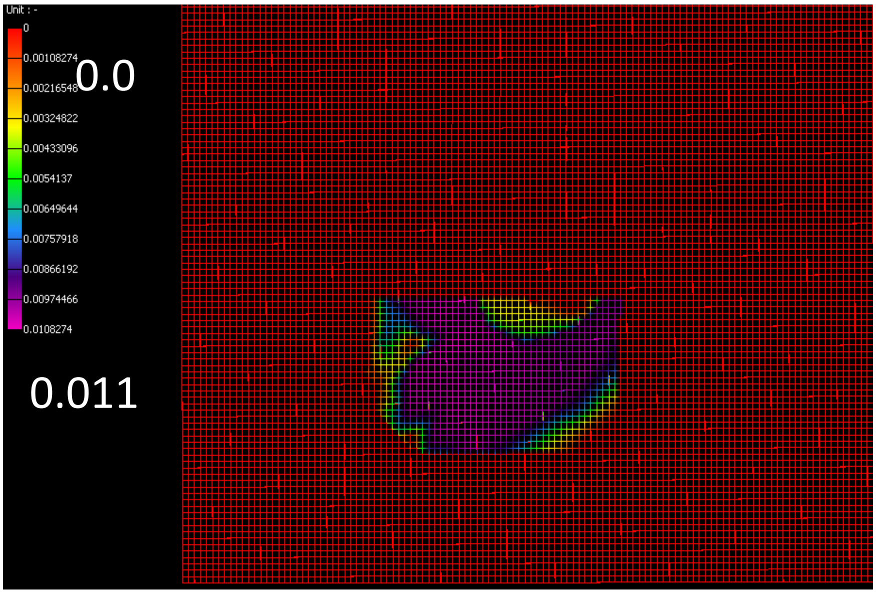

Figure 3.5: Concentrated salt dissolution (shrinkage strain) for the same total amount (painted on mesh).

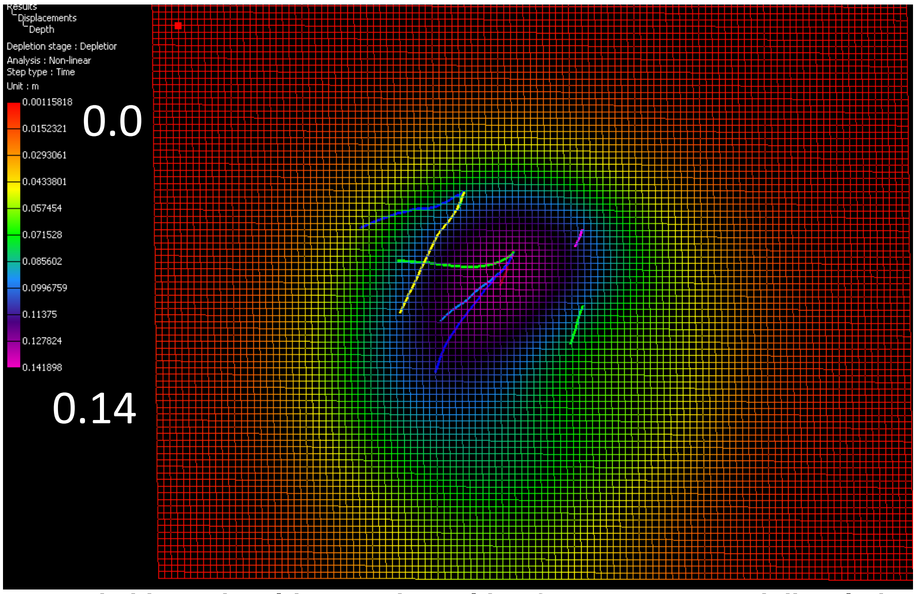

Figure 3.6: Subsidence bowl (0-14 cm) resulting from concentrated dissolution, also showing some well paths.

4. Conclusions

This report describes the impact of Halite dissolution on potential subsidence for the case of low saline water injection into depleted Carbonate gas fields encased in Halite. This was investigated to assess the possible impact of low saline Schoonebeek Oilfield production water injection into the Tubbergen and Rossum Weerselo depleted gas fields which have above described geological setting.

In the original Environmental Impact Assessment, a lot of attention was dedicated to the risk of degrading cap rock integrity through salt dissolution. The EIA concluded that this risk is very low. This was supported by the subsidence calculations done as part of the granted Water Management permits. These indicate that no additional subsidence is to be expected in the base case situation. Nevertheless, the Dutch regulator (State Supervision of Mines) requested to do a further and more detailed study into the risk and determine the worst case subsidence and caprock integrity reduction that could occur.

A simplified (un-faulted) full-field dynamic model was made for the Tubbergen field. This model was used to assess the distribution of the injection water long after injection has been stopped. It show that due to gravity segregation, the remaining gas will collect in the crest of the field and the injection water collects in the down-dip flanks of the reservoir. In order to determine a worst case subsidence scenario, the under-saturated injection water is assumed to be in direct contact with the halite over- and underlying the carbonate reservoir. Furthermore it is assumed that over time the injection water will become fully salt saturated by dissolving the surrounding Halite. A geomechanical model was used to determine the ultimate subsidence bowl caused by this Halite dissolution. Modelling results show that in the very worst case after a period of 8000 to 73000 years a subsidence bowl with a diameter of about 5 km and a maximum depth of 12-14 cm could be formed. This includes sensitivities on the possible distribution of water in the injection reservoir (from fully concentrated in the centre of the field to distributed over the flank regions). The deepest point is expected to be located above the crest of the injection reservoir. The total volume of halite that is dissolved in this case is less than 0.5% of the total halite volume in the layers overlying the carbonate reservoir. Even in this extreme case integrity risks of the halite top seal are deemed to be extremely low.

To arrive at a worst case impact assessment and tests the extremes of the possible salt caprock integrity, the assumptions for this modelling study were on purpose very conservative as explained below:

1] It was assumed that there is everywhere a direct contact possible between the injection reservoir and the over- and underlying Halite sequence. In reality this is not the case as the carbonate injection horizons are over- and underlain by regional anhydrite layers which form a continuous, impermeable and insoluble separation between the injection reservoir and the Halite rock (Ref 1). Only in faulted areas it is possible that Halite is in contact with the injection reservoir. The actual effective contact area is therefore very restricted and consequently Halite dissolution will be severely restricted (Ref 2)

2] It was assumed that all injected water becomes fully salt saturated which represents a 15% to 50% overestimate given that the original formation water in the gas reservoirs was not salt saturated (NaCl concentration of Tubbergen/Rossum-Weerselo formation water is 210,000/270,000 ppm whilst fully saturated brine contains 300,000-320,000ppm at reservoir conditions)

3] In order to facilitate salt dissolution, under saturated water needs to be able to flow towards the reservoir-salt interface and saturated water needs to be able to flow away from that interface. The extent to which such convection cells can be formed critically depends on the Kv/Kh ratio in the carbonate reservoir. In base case the full field dynamic model a Kv/Kh ratio of 10^{-2} was assumed.

Based on geological insights the actual ratio is a factor 100-1000 worse (in the range 10^{-3} to 10^{-4}) which results in a much slower vertical flow within the injection reservoir. In a reservoir of 50m thickness (like Tubbergen) and a Kv/Kh of 10^{-3} it takes almost 8000 years for a convection cell to be formed. For a Kv/Kh of 10^{-4} this is even close to 75,000 years (Ref 2).

The base case assumption for additional subsidence to be caused by water injection in the Twente fields subsidence is expected to be negligible (ref the Water Management Plan).

In the worst case scenario tested here incorporates the above 3 very conservative assumptions and assumes that all of the water is only injected in the upper of the two reservoirs. Despite these assumptions, the impact of Halite dissolution may result in a maximum additional subsidence of 12-14 cm only. This only represents a reduction of 0.5% of the average thickness of the halite overlying the upper (ZEZ3C) Carbonate injection reservoir, implying that even in this extreme case the cap rock integrity will remain guaranteed.

References

[1] Geology description of Twente gas fields: Tubbergen, Tubbergen-Mander and Rossum-Weerselo, EP201310201845, NAM, 2014

[2] Halite dissolution modelling of water injection into Carbonate gas reservoirs with a Halite seal: EP201310203080, NAM 2014

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

[4] Warren, G and Bisschop, R. Schoonebeek Oilfield Redevelopment VAR 3 Field Development Plan Updated Final Version. Assen, The Netherlands. EPE200401201716, NAM, 2006

[5] Weijermans, P.J., Schoonebeek Produced Water Disposal Study: Dynamic Modelling of Water Injection in Depleted Naturally Fractured Zechstein Carbonates, EP201310204003, Horizon Energy Partners, 2004

Appendix 1: Rock parameters geomechanical model

The rock mechanical properties for the carbonates and overburden have not been studied in detail. Little information was easily accessible, given the high age of the field and most of the wells. Since the rock properties are not very important to get a quantitative impression of the subsidence, some basic trends have been, increasing stiffness in depth.

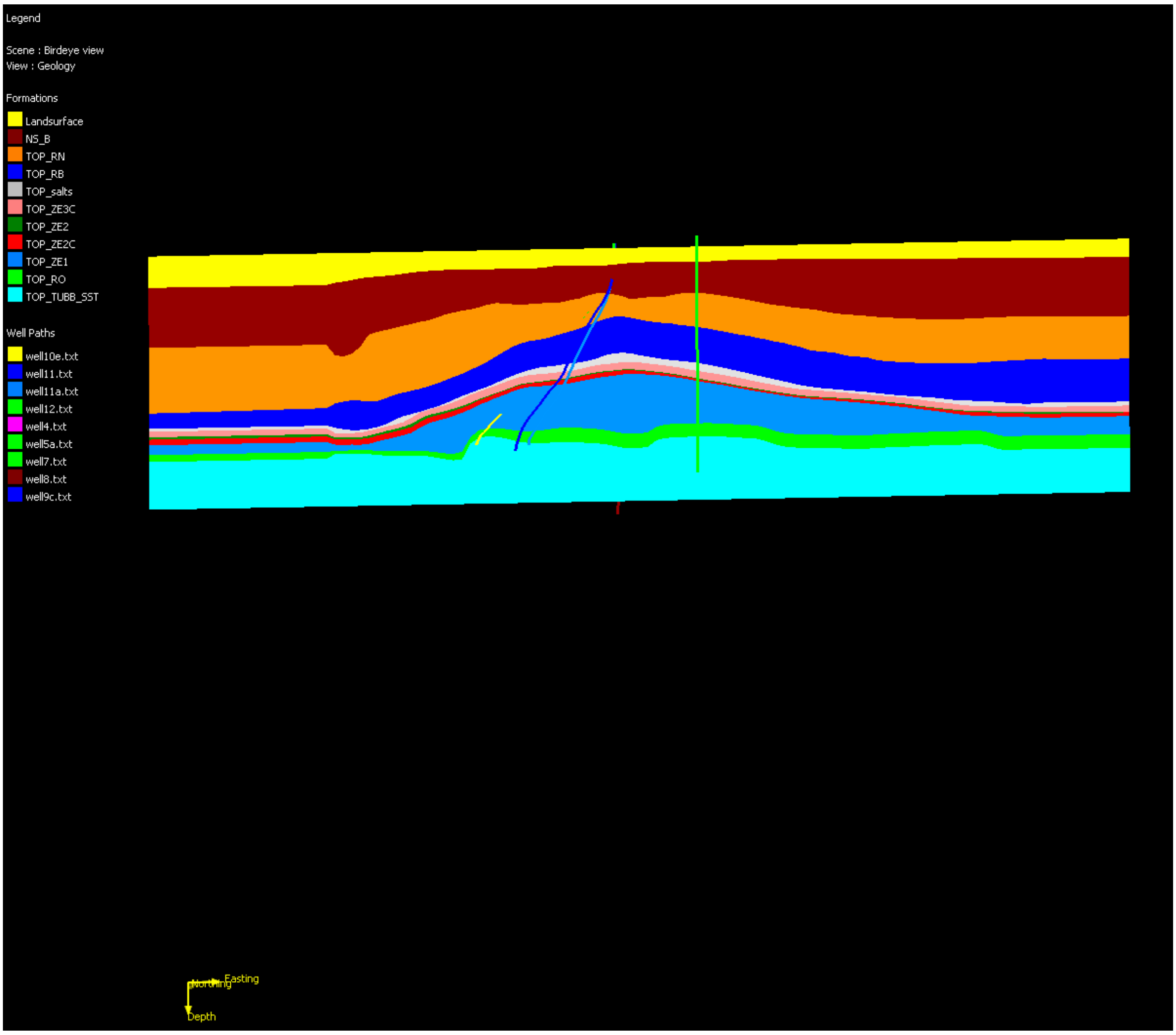

Figure A1: Geology on a cross section.

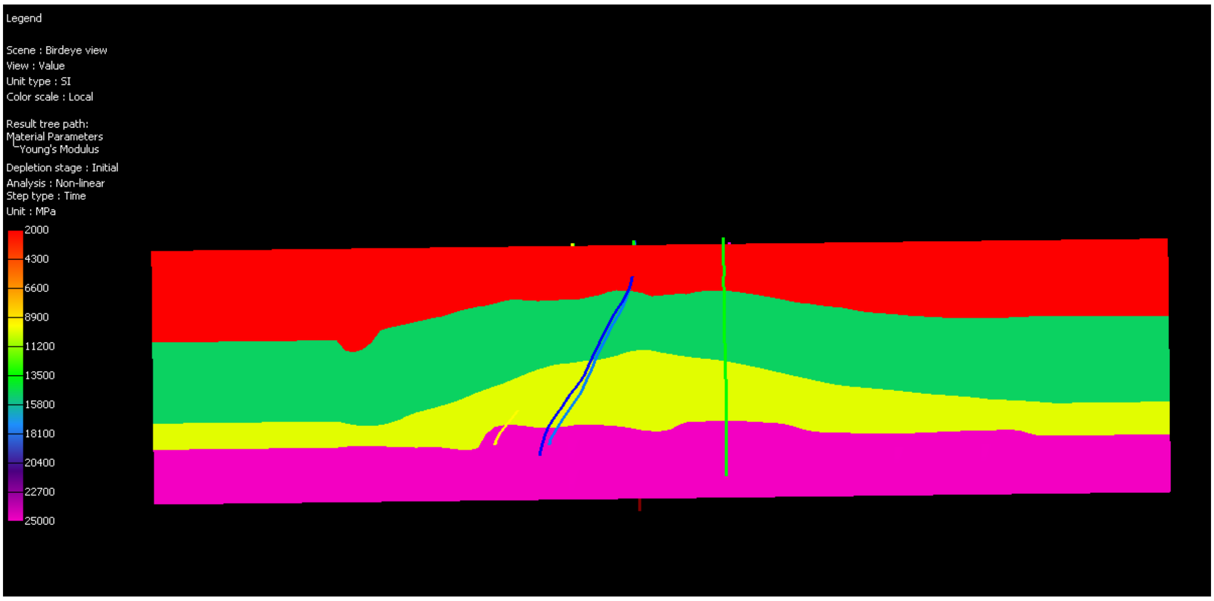

Figure A2: Young’s Modulus on cross section, ranging from 2 to 25 GPa.

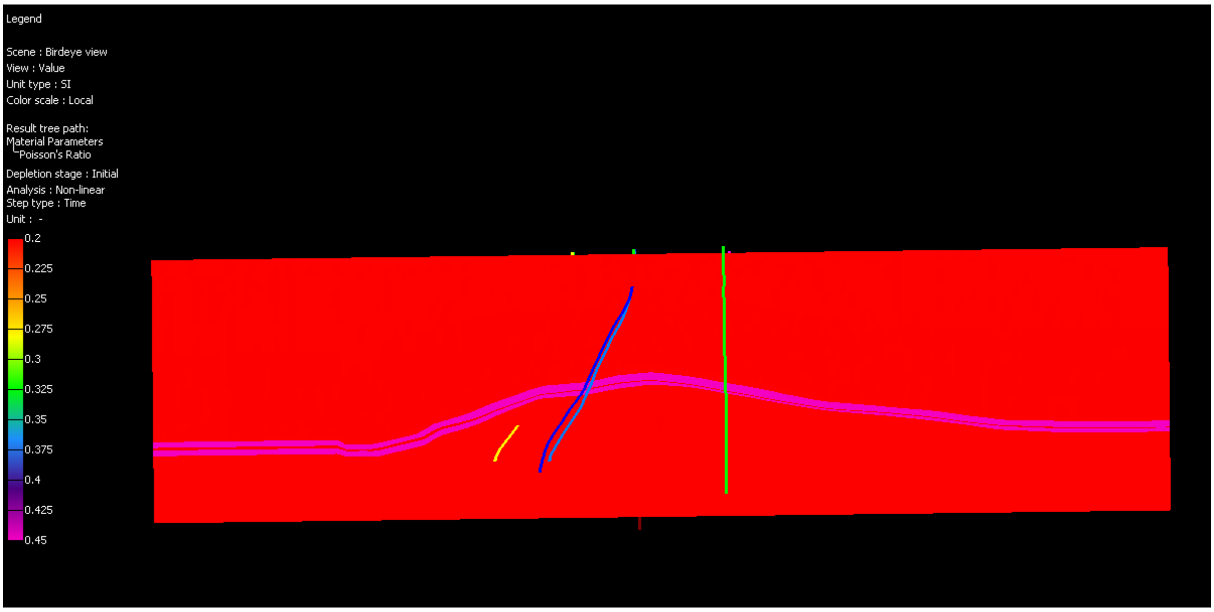

Figure A3: Poisson’s ratio on cross section, constant at 0.2 for all the rocks except the carbonates. Carbonate Poisson’s ratio is 0.45 to force the contraction strain (from salt dissolution) to end up in subsidence .

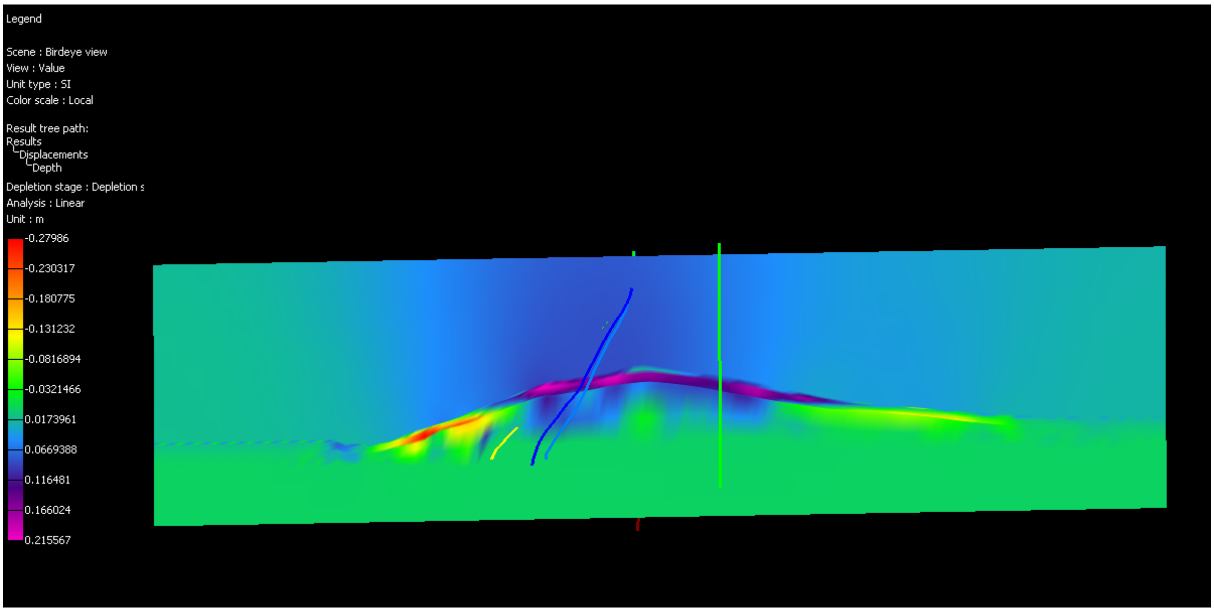

Figure A4: Vertical displacement (subsidence) on a cross section. The red/yellow parts are upheave of the under burden, whereas blue is subsidence of mainly the overburden.