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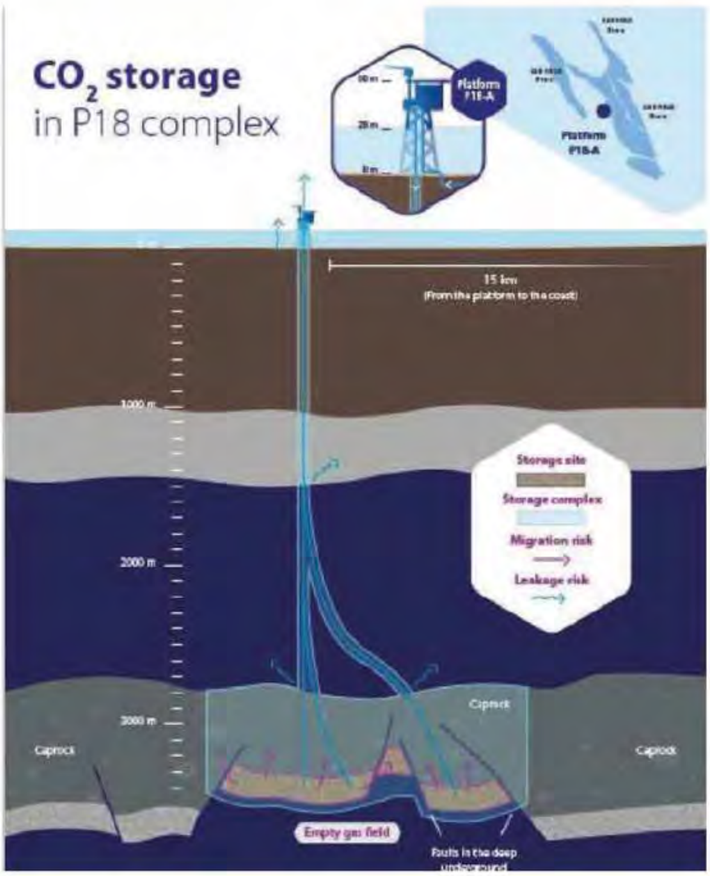
Report

Technical review of Porthos CO2-storage permit application

Author(s)



SINTEF Industry
Drilling and Well
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SINTEF Industri
SINTEF Industry
Address:
Postboks 4763 Torgarden
NO-7465 Trondheim
NORWAY
Switchboard: +47 40005100

info@sintef.no

Enterprise /VAT No:
NO 919 303 808 MVA

Report

Technical review of Porthos CO2-storage permit application

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ABSTRACT

The Porthos project has recently submitted a permit application to the Dutch authorities for injection and permanent storage of CO_2 in depleted gas reservoirs offshore Rotterdam. SINTEF was selected by SSM to act as external experts to perform a technical review of the Porthos permit application, with emphasis on well integrity, monitoring and leakage consequences.

It is found that the technical work in the Porthos application is thorough and SINTEF agree with the main conclusions. There are some inconsistencies, unclarities and minor issues here and there, but the main conclusions are not affected. We recommend that a more in-depth study of temperature profiles in the bottom part of the well should be performed, with special emphasis on addressing the packer to perforations distance.

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1 Introduction

1.1 Background

The Porthos project involves the storage of CO_2 in three depleted gas reservoirs located 25 km offshore from the port of Rotterdam, The Netherlands. Porthos has recently submitted a permit application to the Dutch authorities for injection and permanent storage of CO_2 in these depleted gas reservoirs.

Dutch State Supervision of Mines (SSM) advises the Minister of Economic Affairs and Climate Policy on permit applications, and SINTEF was selected by SSM to act as external experts to perform a technical review of the Porthos permit application. This included review of approx. 800 pages of technical documentation in addition to the actual permit application of approx. 300 pages. (The list of documents made available for review is given in the Appendix.)

SINTEF was assigned three topics to review: Primary subject 1 on "Well integrity and behaviour", Primary subject 2 on "Well-related monitoring and risk mitigation", as well as a secondary subject on "Leakage consequences in the overburden". It should be noted that the fourth subject "Reservoir and cap rock integrity", was not a part of SINTEF's review and has been reviewed by another expert team.

1.2 Objective of this report

This report summarizes the main findings of SINTEF's technical review of these three topics, where each topic is described in a separate chapter. Furthermore, during the review it became apparent that the topic "Measurement and modelling of well temperatures", which was partially overlapping between both primary subjects, was of particular importance. Therefore, this topic is discussed in a separate chapter.

SINTEF's emphasis while performing this technical review has been to evaluate relevant safety aspects of the Porthos projects. For example, important questions that have been considered are: Is the risk of well barrier failures sufficiently analysed and understood? Is the combination of monitoring methods suitable and sufficient for detection and mitigation of CO_2-leakages? Do we, as technical experts, agree with the conclusions in the technical documentation? Do we find any significant limitations in the underlying arguments and analyses?

We have summarized our findings in the four main chapters of this report. Major issues have been highlighted as "recommendations", while minor issues have been denoted "comments".

SINTEF

2 Well integrity

The well integrity assessments of the P18 wells are thorough and are described in detail in B7 CO_2 storage feasibility in the P18-2 depleted gas field and B13 Well containment note, as well as summarized in the main application. The well barrier envelopes have been defined using the NORSOK D-010 and ISO 16530-1 standards, which are internationally recognized as the most prominent well integrity standards available. Two independent well barrier envelopes are defined for all wells, where for example the primary well barrier envelope consists of a SSSV, which will improve well operational safety.

All injection wells are planned to be re-completed during a workover before injection, to ensure that all completion string and X-mas tree components are compatible with CO_2. Acceptable CO_2 resistance should be documented for all materials, where for example Cr steel of sufficient quality could be used for steel components. Furthermore, CBL and USIT logs will be run during the workover to determine the integrity of the cap rock cement, which will provide crucial information about potential presence of microannuli prior to CO_2 injection. It should however be noted that if prominent cement de-bonding is detected by the CBL/USIT logs, then these microannuli may influence the apertures and geometries of the microannuli subsequently formed during CO_2 injection, and thus also potentially increase the risk of CO_2 leakages. If so, all microannuli and CO_2 leakage simulations should be re-done.

A major emphasis during the well integrity review was on the formation of cement microannuli and of subsequent potential CO_2 leakages through these leak paths. The main conclusion regarding potential well leakages from the Porthos application is that yes, cement microannuli will form during CO_2 injection, but these microannuli do not represent a significant risk for CO_2 leakages. We agree with this conclusion, as outlined in more detail below.

2.1 CO_2 leakages through microannuli

Microannuli formation is the most prominent cement failure mechanism in CO_2 injection wells. When cold CO_2 is injected into the well, the well and near-well region cool down and subsequently, the casing, cement, and rock contract due to this cooling. Consequently, the cement sheath de-bonds towards the casing and/or formation, thereby creating microannuli (Bois et al., 2011, 2012; Nygaard et al., 2014). These microannuli could act as potential leakage paths for downhole fluids. For example, in a well after 30 years of CO_2 injection, prominent leak paths at both the cement-casing and cement-formation interfaces were found after coring (Carey et al., 2007).

Regarding microannulus apertures, it is important to note that microannuli do not have uniform and well-defined geometries (Vrålstad et al., 2019; Vrålstad and Skorpa, 2020), as visualized in Figure 1 below. Microannuli have complex and non-uniform geometries, and consequently, flow through micronnuli is non-linear and not easily predictable (Skorpa and Vrålstad, 2018; Corina et al., 2021). A constructive approach to define microannuli apertures is thus to distinguish between the "mechanical" aperture, which is the actual, local width, and the "hydraulic" aperture, which is the average width estimated from flow measurements assuming a uniform microannulus geometry with smooth walls around the full cement sheath circumference (Stormont et al., 2018; Garcia Fernandez et al., 2019). Correct assessments of actual microannulus apertures are therefore difficult to obtain, but estimations of hydraulic apertures are possible in experiments by measuring the axial fluid flow through the cement sheaths. In such cases, the measured hydraulic aperture will be smaller than the actual, mechanical aperture.

Finally, it should be added that the cyclic temperature variations experienced due to repeated shut-ins and start-ups etc, can be detrimental for the cement integrity (Nygaard et al., 2014). However, this thermal cycling will not increase the apertures of the created microannuli (unless the temperature difference is increased), but such cyclic loads can induce more cement de-bonding and thus create larger microannuli geometries (Vrålstad et al., 2015).

Figure 1: Examples of experimentally obtained, real microannuli geometries (Figure from Vrålstad and Skorpa, 2020)

2.1.1 Estimation of microannuli apertures in Porthos wells

The DIANA numerical tool was used to predict the temperature variations in the near-well region during to CO_2 injection. Furthermore, DIANA was used to estimate the stresses at the cement-casing interface due to casing and cement contraction during cooling, and it was found that cement-casing microannuli will form during CO_2 injection. DIANA is a finite element numerical model that has been used by TNO for many years and presented in several peer-reviewed publications (Schreppers 2015; Orlic et al. 2016, 2018; Moghadam et al., 2020), and there is no reason to believe that the obtained results from DIANA are less accurate than results from other, similar numerical models. The DIANA results can be considered trustworthy.

There are however some limitations and uncertainties with the DIANA simulations. For example, it is assumed that cement is elastic and that the surrounding rock is ductile. Both cement and rock are known to be brittle materials, although they do exhibit elastic properties under low strain conditions. Furthermore, the initial state of stress in the cement is assumed to be zero (for simplicity), and it is not stated whether the confining stress in the rock is taken into account when performing these simulations. Although the main conclusion will probably not be affected, i.e. that a microannulus will form as a result of high tensile stress at the cement-casing interface, it could have been useful to perform a sensitivity study to determine the potential impact of these uncertainties.

DIANA was however not used to estimate the obtained microannuli apertures; a more simplified, analytical approach was used for microannuli aperture estimation. Although the approach was simple (and thus cannot be expected to be correct), the obtained aperture sizes are in fact plausible. It is estimated that the resulting apertures are approx. 35 μm, with 30 μm added as and additional safety margin, resulting in estimated microannuli apertures of approx. 65 μm. These microannuli aperture values assume complete geometrical uniformity and smooth wall surfaces, and are thus neither mechanical nor hydraulic, but may be most relevantly compared with hydraulic aperture values due to the assumed uniformity.

These obtained aperture values are within the ranges typically found in experimental and field studies of real microannuli: Aas et al. (2016) and Moghadam et al. (2020) performed large-scale yard tests of casing-cement samples and found hydraulic apertures of approx. 65 μm and 35 μm, respectively. Therond et al. (2017) performed large-scale experimental tests of cold fluid injection, compared with cement integrity modelling, and found hydraulic microannuli apertures of less than 11 μm. Finally, Skadsem et al. (2020) investigated a well section retrieved from an abandoned North Sea well and found microannuli with hydraulic apertures of below 39 μm.

Therefore, although the estimated microannuli apertures are probably not correct, the obtained aperture sizes are plausible.

2.1.2 Estimation of CO_2 leak rates in Porthos wells

A major point in the Porthos leakage risk assessment is that since CO_2 will be injected into a depleted reservoir, the pressure in the overburden above the reservoir will be higher than the pressure in the reservoir, at least until near the end of the injection period. Consequently, there will be a negative pressure difference across the cement barrier, and thus no CO_2 leakages through the microannuli in the cement. This conclusion is correct.

With respect to cement sheath integrity, it is important to note the difference between cement mechanical integrity and hydraulic integrity (Bois et al., 2019), where the mechanical integrity reflects the presence of defects such as microannuli and radial cracks, and hydraulic integrity describes the actual sealing ability of the cement. In other words, for loss of hydraulic integrity to occur, two requirements are needed: First, the presence of a continuous leak path through the entire axial length of the cement, and second, a sufficient pressure difference across the cement to cause fluid flow through this leak path. In the Porthos case, the negative pressure difference across the cement therefore ensures that there will not be pressure-driven CO_2 leakages through the microannuli, until near the end of the injection period, where the reservoir pressure is close to hydrostatic (or slightly above in the near-well area).

Consequently, resulting CO_2 leak rates at the end of the injection period have been calculated, and the approach used to determine the leak rates is interesting. To acknowledge the fact that microannuli geometries are non-uniform and complex with considerable surface roughness, the microannulus geometry is treated as a porous medium by the Porthos team. Thus, a permeability value has been assigned to the microannulus and the resulting fluid flow is calculated with Darcy's law. The assigned permeability values (up to 10^{-12} m^2) are within or above the range of experimentally obtained permeabilities found for microannuli and cracks in well cement (Stormont et al., 2018; Skorpa and Vrålstad, 2020). This approach is not completely correct, but it takes the microannuli non-uniformity into account and thus provides plausible results.

Therefore, the estimated CO_2 leak rates through the microannuli are plausible.

2.1.3 Closure of microannuli due to calcite precipitation

Chemical reactions between CO_2 and Portland cement have been extensively studied and is well understood (Zhang and Bachu, 2011; Carrol et al., 2016). For example, Portland cement consists in large part of $Ca(OH)_2$, which will react with CO_2 and form $CaCO_3$. This reaction is known as carbonation of cement. In this regard, it should be noted that $CaCO_3$ occupies more volume than $Ca(OH)_2$. Therefore, when $CaCO_3$ precipitates inside small cavities or defects in the cement, such as cracks or microannuli, the defects may close. This process is known as self-healing of cement.

There are two factors that influence whether fractures and openings will self-heal or not: the flow rate of CO_2 through the fracture, i.e. the available time for the reaction to occur (residence time), and the aperture of the fracture (Brunet et al., 2016; Carrol et al., 2016). This is illustrated in Figure 2 below, where it is seen that self-healing will occur for high residence times and small apertures.

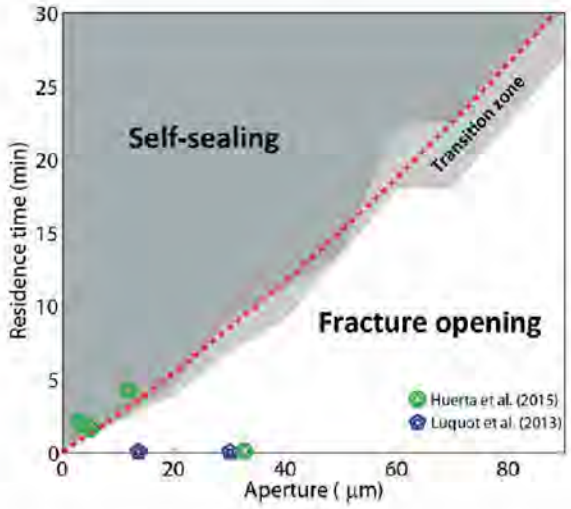

Figure 2: Influence of aperture and CO_2 residence time on self-healing of cement fractures (Carrol et al., 2016)

For the Porthos wells, this figure (by Carrol et al., 2016) was used in B13 Well containment note (Chapter 8, pages 57-59) to illustrate this point. It is concluded that for the combination of small microannuli apertures (below 65 μm, high CO_2 residence time due to low flow rates (up to 0.04 m/s), and the several hundreds of meters of cement sheath length in the cap rock, it is likely that $CaCO_3$ will precipitate and close the microannuli if CO_2 should leak through the cement from the reservoir. There is therefore no significant risk of CO_2 leakages from the Porthos wells. We agree with this conclusion.

As an appendix to the above discussion, we will add a short remark on durability of Portland cement towards CO_2. It should be noted that since $CaCO_3$ occupies more volume than $Ca(OH)_2$, carbonation of cement is a self-decelerating process. Carbonation reactions are dependent upon diffusion of CO_2 into the cement pore network, and further carbonation and continued CO_2 diffusion are thus delayed by the precipitation of the more voluminous $CaCO_3$. Consequently, carbonation of Portland cement is a very slow process, and the carbonation front might only proceed approx. 30 mm after 1000 years (Zhang and Bachu, 2011). Carbonation of Portland cement will therefore not constitute a significant well integrity issue.

2.2 Potential flow due to buoyancy of CO_2?

Due to the initial below-hydrostatic reservoir pressure, brine will flow (slowly) into the reservoir through any microannuli with hydraulic connectivity through the caprock. As discussed above, it is assumed a Darcy-like flow in narrow fractures where the expected and worst-case flows based on estimated microannuli aperture are calculated based on worst-case fracture permeability (and relative permeability) and the simulated reservoir pressure development. Towards the very end of injection CO_2 may flow out of the reservoir due to reservoir pressure locally exceeding the brine hydrostatic pressure. Total amount of CO_2 escaping this way is expected to be an insignificant fraction of total stored CO_2 even for the worst-case assumptions.

However, although there will be downwards flow of water through the microannuli throughout most of the injection period, an important question is whether CO_2 nevertheless will migrate upwards due to buoyancy?

This question is discussed in the technical documentation, and it is concluded that leakage in a potential microannulus due to buoyancy of CO_2 can be neglected as long as the local pressure in the reservoir is lower than hydrostatic. An attempt at a detailed analysis is presented in B13 Well containment note, section 15.4.3 (pages 99-100). The argument given is that the downward pressure gradient in a microannulus filled with formation brine will be much larger than the buoyancy forces acting on a CO_2 bubble at the entrance to the microannulus from the reservoir. Even if the pressure difference between microannulus and reservoir is only 1 bar, the upward force (by buoyancy) would be somewhere between 7 and 10 orders of magnitude lower than the downward (or upward) force (by pressure difference). The presence of methane in the reservoir is not discussed, but the different density would not alter the conclusions.

We agree with the conclusions regarding possible vertical CO_2 flow, but this analysis on buoyancy, while making an attempt at summarising the relevant forces acting on CO_2 and brine in a microannulus, is not complete or even correct. The force balance discussion is peculiar as it compares the integrated downward force across the whole microannulus with the buoyancy force for one bubble, as if the brine and CO_2 bubble were pushing from opposite sides on a stiff membrane. It would be better (and simpler) to compare the potential maximum rising velocity of gas bubbles small enough to fit inside the microannulus, with the downwards flow of brine resulting from the pressure potential gradient in the microannulus. Theory and experimental investigation of the rising speed of gas bubbles in bulk and even in capillary tubes is a well-developed research area.

Still, following the argument in B13, the conclusion would be unchanged if one considers a doughnut-shaped CO_2 bubble displacing its volume where the diameter of the doughnut fills the whole 100 μm annulus. Then the buoyancy force approximates $5 \cdot 10^{-6}$ N, as compared with 2000 N downward force (assuming 300 bar pressure at the interface). However, this last assumption, of sustaining 300 bar at the interface seems highly improbable.

Furthermore, the analysis in chapter 15.4.4 on capillary pressure also seems odd, with a lengthy discussion of pendant drops falling from the microannulus (presumably into the open hole below the lowermost casing?). This discussion ends up with an expression with an unknown parameter 'N', and no mention at all of the brine/CO_2 interfacial tension, which would be relevant. The conclusion of that chapter then disregards the calculation altogether and goes on to refer to personal communication with TNO staff to justify the conclusion, which is probably correct, by the way.

Therefore, although we do not agree with the approach or calculations regarding potential upwards migration due to buoyancy of CO_2, we do agree that it is unlikely that this will occur, and that buoyancy of CO_2 can be neglected as long as the local pressure in the reservoir is lower than hydrostatic.

2.3 Potential methane leakages from the wells?

The influence of remaining methane in the reservoir on the gas density is not discussed. The methane to CO_2 density ratio depends on pressure and temperature. For most reservoir conditions it is between 0.2 and 0.3, but can be <0.1 for temperatures below 30 °C at 50-100 bar. These conditions would be relevant in the first phase of HP operation of the CO_2 pipeline. However, at this point CO_2 will already have been injected for some time to increase the reservoir pressure from 20 to ~50 bar, and the gas around the injection wells can be assumed to be mainly CO_2. The influence of remaining methane on possible leakage rates can therefore probably be neglected.

2.4 Conclusion and recommendations

The main conclusion from the Porthos project regarding potential risk of CO_2 leakages from the wells can be summarized by this statement: *It is concluded that the combination of residence time and small aperture of the microannuli will most likely result in sealing of a leak path as a consequence of calcite deposition. It is therefore an effective barrier with low uncertainty.* (Application, Section III, p 72)

We agree with this statement and support the conclusion that there is no significant risk of CO_2 leakages from the P18 wells.

However, we do have one major concern regarding the estimation of microannuli and resulting CO_2 leakages: the Porthos team have solely focused on cement-casing microannuli, with no mentioning of cement-rock microannuli. It is well-known that cement de-bonding may also occur at the cement-rock interface (Carey et al., 2007), so it is thus surprising that no calculations of cement-rock microannuli have been performed for the Porthos wells.

Recommendation (minor): Additional simulations should be performed to determine microannuli formation at the cement-rock interface, as well as to estimate the resulting microannuli apertures and CO_2 leak rates.

3 Monitoring and risk mitigation

The CO_2 storage permit application describes a draft monitoring plan which covers pre-injection, injection, post-injection, and post-closure phases. The monitoring targets four sub-areas: operation, CO_2 distribution in reservoir, leakage paths, and surrounding area and the environment. The operational monitoring plan is detailed, relying mainly on conventional methods, and appears sound and sufficient for risk mitigation. The reservoir monitoring plan is significantly simpler, consisting only of bottom hole (above packer) temperature and pressure measurements for comparison to and calibration of the reservoir model. The leakage path monitoring plan is extensive and based on state-of-the art methods. However, the possibility of detecting leakage on the outside of the well is uncertain. Finally, the plan for environmental monitoring covers a range of methods but could profit from further investigation of the use of DAS for micro-seismic monitoring.

A thorough risk assessment, using the so-called bow tie method and described in detail within the application, provides the basis for the monitoring plan. A control and alarm management system is also part of the monitoring plan. This will generate alarms in case of measurements deviating from expectations, indicating the need for additional monitoring or corrective measures to prevent failure of barriers.

3.1 General comments to monitoring plan

The application states that the described plan is tentative only and will be revised during the pre-injection phase. Furthermore, we find that the plan described in B7 Section 19 is more complete than the application itself, but also that there are several inconsistencies with the application (leading document):

- Application refers to micro-seismic monitoring only using KNMI network, but table in B7 Section 19 proposes use of geophones or DAS
- Monitoring wells are mentioned in the B7 Section 19, but not in the Application
- Baseline seismic data and contingency seismic in case of suspected leakage is mentioned in B7 Section 19, but not considered in the Application

Comment We suggest that the monitoring plan is carefully updated, taking suggestions and recommendations into account in time so that any potential baseline measurements (e.g., seismic and microseismic) can be done before the start of the injection. The revision is an important opportunity to develop a single consistent plan.

Furthermore, observation bandwidths of the control and alarm management system seem to be somewhat arbitrarily chosen. Defining these levels appropriately is important to avoid a too sensitive or unsensitive system. This requires a more detailed study. The levels may also have to be updated during operation, but only after first having carefully investigated whether reservoir models need to be recalibrated.

3.2 Leakage detection and monitoring by DTS/DAS

It is planned to re-complete all wells during a workover before injection starts, and the new completion strings will be equipped with fiber-optic cables (both DTS and DAS). Although not used routinely, fiber-optic cables have been installed and used in O&G wells for several years (Algeroy et al., 2010; Wu et al., 2016; Bale et al., 2020), as well as in geothermal wells (Raab et al., 2019). The reliability of such monitoring technologies should be well understood. There is however a risk that the fiber-optic cable is damaged during installation (Raab et al., 2019), but if the system is installed undamaged it will function properly. A critical component during installation may be the (wet) connector in the well head. The fiber-optic cables are installed along the outside of the tubing string. The main function of the DTS system will be to measure the temperature profile along the tubing, which will be vital input to understanding the temperature conditions in the well and reservoir. The main function of the DAS system will be to monitor the tubing integrity.

The application suggests using DTS/DAS in the injection wells to detect leakage events (on the outside of the casing). At the same time, it is mentioned that probably only larger amounts of leakage can be detected. During an ongoing injection, the signal related to the leakage is likely to be obscured by the noise related to the injection itself. It may be possible to extract the signal related to the leakage if the frequency ranges of injection and leakage related vibrations are different, or if the shape of the leakage signal is well known and can be filtered out. The shape of the leakage signal is most likely case dependent, varies with the CO_2 phase, and may also vary along the well.

We agree that it is unlikely that the DTS or DAS system will detect any potential CO_2 leakages in microannuli behind the casing. There are cased-hole logging tools available that can potentially detect the noise from flow behind casing (Gardner et al., 2019), but the estimated likely range of CO_2 leak rates (Application Section III, Chapter 6.2.4) are probably too small to be detected by such tools.

However, the application document mentions DAS as possibility for monitoring of microseismic events. While the monitoring plan contains microseismic monitoring based on local injection and monitoring wells in P18 using DAS and downhole geophones, the application concludes that DAS is an untested technology with low resolution and lacking directional information and only the existing KNMI should be used for the microseismic monitoring.

We believe that well-based DAS fibers should be considered as part of the microseismic monitoring. DAS has become a technology also used in commercial settings and has shown to provide results comparable to conventional geophones. Since the DAS cables in the injection wells will be attached to the tubing, seismic signals will experience some energy loss and attenuation while traveling through the annulus, casing and the well to the DAS cable. The long vertical extent of the DAS cable can be expected to provide good directionality regarding the depth of the event location. In addition, the use of P- and S- arrival time differences can provide a good estimate of the distance of the event location from the well, given a reasonable velocity model is available. To provide full directionality at least three wells equipped with DAS should be used for monitoring. While the noise from the CO_2 injection may potentially mask the seismic signals in the injection well, any non-active injection wells should be relatively undisturbed. If dedicated monitoring wells are used, additional geophones at the bottom of the wells are recommended for additional sensitivity, directionality and for triggering.

As regular (active) seismic monitoring may be difficult due to the heavy traffic in the P18 area, the DAS and geophone downhole installations may also be used for sparse seismic conformance monitoring. This would only require a source at the sea surface (e.g., airgun), which may be towed/deployed from a relatively small vessel. In addition, the receivers would be close to the reservoir, providing higher sensitivity.

3.3 Monitoring by seismic?

The application document mentions two main risks for leakage: Lateral leakage, where the CO_2 is migrating laterally out of the storage area, and vertical leakage, where upward migration may occur along the wells and faults.

We found that while the monitoring plan appears comprehensive, it appears that in the application document seismic monitoring that may be used for covering the lateral leakage is not foreseen. The application document describes seismic monitoring of CO_2 in the reservoir as not likely to succeed as the expected contrast is estimated to be too small. The document, however, mentions "one-off" monitoring in case of leakage. A corresponding baseline survey does not appear to be planned.

We are concerned that no baseline seismic data seems to be planned. Especially for smaller amounts of (vertical) leakage solid seismic baseline data will be vital for the detection and monitoring of leaking CO_2.

Comment: Seismic is the backbone of most monitoring systems and a way of getting directional information about plume behaviour/movement. A more thorough assessment (than the Willemsen report/slides referred to in Application) should be performed. This could include reservoir modelling and a more detailed seismic sensitivity study.

The application document also mentions microseismic monitoring to detect seismic activity e.g., as indication of reactivation of pre-existing faults. While the monitoring plan includes the use of DAS and downhole geophones in several monitoring wells, the microseismic monitoring described in the application document will only rely on the existing regional KNMI seismic network. The application states that the risk was negligible and that according to SSM guidelines the use of the regional KNMI seismic network is sufficient. The application states that no seismic activity had been detected in P18 in the past. The magnitude of completion of the KNMI network for P18 events is 2.

It should be noted that the SSM guidelines may not apply for this case. In addition, the magnitude of completion of the KNMI network for P18 events is 2, which means that events smaller than magnitude 2 may not be detected. We consider this as a very high threshold. Microseismic events at other CO_2 storage sites typically are much smaller than magnitude 1 (even recording events $< M=-1$). If the KNMI network was used for the assessment of microseismic activity in the past, the fact that no microseismic events were detected does not mean that none occurred.

3.4 Conclusions and recommendations

The monitoring plan is comprehensive, but somewhat inconsistent and should be updated. We also suggest that use of seismic is more thoroughly considered as monitoring method. It is unlikely that the DTS or DAS system will detect any potential CO_2 leakages in microannuli behind the casing. However, DAS can potentially be used for other purposes.

Recommendation (minor): Consider using DAS in non-active injection wells as part of microseismic and/or seismic monitoring.

4 Measurement and modelling of well temperatures

The temperature in the well is important to know for several reasons. For example, from a well integrity perspective, the cooling of the well during CO_2 injection causes the formation of microannuli, and it is thus crucial to accurately predict what the well temperature will be during injection. The well temperature is monitored by DTS cables along the tubing string, in addition to the temperature and pressure gauge at the packer. These monitoring points are the only information available that can be used to validate and update well injection and reservoir models.

The OLGA simulations summarized in B10 - Flow Assurance Study FAS report, are the main part of the technical documentation describing the temperature development in the Porthos wells. Furthermore, results and discussion of temperature in wells, near-well area and reservoir can also be found in B9: P18 Porthos well injectivity, B12: P18 CCS: Seismic risk evaluation, and B13: Well containment note. It should be noted that all these different temperature discussions are not always consistent, and it is unclear how the simulations have been coupled or integrated.

4.1 OLGA simulations of temperature

The B10 - Flow Assurance Study FAS report provides a description of how the operational envelopes have been derived from simulations using the known flow assurance constraints. The system in question contains three main system parts: 1) Low-pressure (LP) pipeline, 2) High-pressure (HP) pipeline and 3) Four injection wells (as seen in Figure 3).

Figure 3: Overview of the Porthos CCS transport system.

The flow assurance constraints are:

1) Two-phase flow should generally be avoided to prevent increased pressure drop and liquid surges.
2) The annulus fluid temperature must not fall below 0°C to avoid freezing.
3) The instantaneous temperatures anywhere in the system must be higher than -40°C for the sake of pipe material integrity.
4) The bottom-hole temperature must be maintained at least 3°C above the hydrate formation temperature.

The main conclusions from the report are: In the LP pipeline, liquid will inevitably accumulate in low points due to impurities in the system, hence regular pigging will be necessary. In the initial period of operations (1-2 years), the HP pipeline must be operated in gas mode with fully open (or fully closed) valves. In this period, sufficiently high flow rates must be maintained to prevent liquid accumulation in the HP pipeline. After the initial period, when the HP pressure exceeds 40-50 bara, the HP pipeline must be pressurized to operate in dense phase mode (> 85 bara). Wellhead choking will now be necessary to maintain pressure, and this can potentially lead to low temperatures downstream the wellhead valve, especially in the early phase, when the reservoir pressure is low. Hydrate formation downstream well-head choke can be avoided using MeOH injection.

One of the primary flow assurance constraints on the operational envelope is the danger of hydrate formation in the near-wellbore region. The report suggests that the free water in the near-wellbore region might completely evaporate during the initial period, in which case there would be no real danger of hydrates in the near-wellbore region. This matter will be investigated in the future. In addition to providing operational envelopes, the report also provides general operational guidelines based on steady-state and transient simulations. These guidelines concern operations such as shut-in, restart, blowdown, switching between gas- and dense phase mode, etc.

Overall, the assumptions applied in the simulations are reasonable. In cases with uncertain assumptions, a "conservative" approach has generally been used, meaning that they aim to err on the side of caution. Consequently, the simulations should generally either be close to reality, or "pessimistic". There are however certain assumptions applied in the simulations that are not necessarily "conservative":

- The well injection indices used in the simulations are not well known, are only indicative based upon previous well production data. It is not clear how the values of the well injection indices influence the results.
- The wells have been simulated using pure CO_2, while the real system will contain impurities, and the implications of this simplification are unclear.
- In the well model, the width of the rock formation layer is set to 12.75 meters without justification, presumably implying that the temperature 12.75 meters from the well will not change significantly in the relevant time frame. This choice will influence the predicted temperatures in the tubing and is thus important for predicting the temperatures in the near-wellbore region, where there is a potential hydrate risk.

Furthermore, there are also some other, minor issues that could be taken into account: First, the simplified model used for establishing the operational envelopes does not appear to match OLGA-simulations as well as one might expect (section 6.5). This seems strange since the simplified model is based on OLGA-simulations. Secondly, the predicted temperatures downstream partially closed valves are known to be grid dependent, where large cells will yield non-conservative values. It is not clear from the report whether this matter has been accounted for.

4.2 Near-well temperature development

The topic of near-well temperature development is discussed in section II, chapter 3.5 and 3.6 in the application document. A summary of the physical effects that can cause cooling of the reservoir is given, together with a presentation of some worst-case scenarios. The most important physical effects are the Joule-Thomson cooling, whereby a non-ideal gas cools down during expansion, and the evaporation cooling, whereby a liquid cools to supply the heat of evaporation. Possible effects of impurities in the CO_2 are briefly discussed, with reference to expected compositions supplied in the Porthos project.

Reference is made to several of the previous studies in the supplementary material. Temperature development downhole and in the reservoir is influenced by several factors including pressure and temperature of CO_2 at the wellhead, wellhead, flow rate, heat inflow along the well path, reservoir pressure, and well injectivity. Discussion of temperature development in the well and in the reservoir can therefore be found at several places, such as B10: Flow assurance study FAS report, B9: P18 Porthos well injectivity, and B12: P18 CCS: Seismic risk evaluation. The analysis of the various assumptions made in these studies is complicated by having to collect and compare information from the documents. Even if a list of models used in the studies is presented in section II, chapter 3.1 of the application, the boundary conditions and other assumptions important for the temperature modelling are not presented there.

Furthermore, results of near-well temperature development by DIANA simulations are shown in B13 Well containment note (section 15.3). Examples are given for a worst-case flowing CO_2 temperature of 15 °C, with further aperture calculation and flow modelling made with downhole temperature calculated with OLGA simulations.

Despite the apparent lack of a coherent use of boundary conditions, it is our opinion that the bottom-hole temperature and the influence of the injection of CO_2 at a lower temperature than the initial reservoir temperature are given a thorough discussion in the application and the supplementary material. All relevant physical effects have been discussed and evaluated. Complex non-linearities and differences in time and length scale between processes in the pipeline, well and reservoir are, however, at play. Analysing each sub-system in turn may therefore be necessary to enable a sufficiently detailed analysis. The topic of coupled (dynamic) well-reservoir simulations is very much of current interest among potential operators for CO_2 storage in depleted oil and gas fields. We can therefore hope for progress on this research topic in the coming years. The boundary conditions used for each subsystem for the current application could be better justified. Some of the 'worst-case' scenarios for near-well reservoir temperature development could be too unrealistic to provide useful guidance. But as it turns out the scenarios demonstrate that even if pushed beyond reasonable injection limits the integrity of the storage complex does not seem to be compromised.

4.2.1 Well operating regimes

A wide range of operating conditions for the injection wells are simulated and reported in B10. One of the primary goals is to avoid temperature in the near-well region dropping into the CO_2-hydrate stability region.

Combinations of operating parameters giving bottom-hole temperature (BHT) below 15 °C are therefore excluded from the list of valid combinations. This temperature limit takes into account the possibility of further decrease of CO_2 temperature if the pressure drop from the well out into the reservoir is large. This can happen in particular for high injection rates and low injectivity.

The analysis in B10 shows that the switch-over to high-pressure operation of the offshore pipeline should not be performed for too low reservoir pressures. In worst-case situations, little heat will be supplied from the formation along the well and CO_2 will be on the gas-liquid phase boundary line at the bottom of the injection well. BHT will then be given by the bottom hole pressure. In case of high injectivity and low difference between BHP and reservoir it is then important that the reservoir pressure is high enough that the corresponding temperature on the phase line is above the hydrate temperature. It is therefore recommended that the HP switch-over is not conducted before average reservoir pressure approaches 50 bar. However, this depends on injectivity, which will be carefully re-analysed during the initial injection.

Our opinion is that this seems to be a correct analysis and good design principles. However, there is a mix of units used throughout the supplied documentation when flow rates are discussed. The reader needs to juggle kg/s, t/h, Sm^3/day, Mtpa, etc. It is recommended that a more unified use of units is attempted.

Comment: We could not find any illustration or discussion of the expected temperature drop in the CO_2 from the well into the reservoir (e.g. for combinations of injectivity, injection rate and reservoir pressure given by the base injection cases). This would be helpful in assessing whether the assumed BHT lower limit of 15 °C (and 22 °C for some wells) is indeed sufficient for maintaining CO_2 temperatures above the hydrate stability region also away from the wells.

4.2.2 Reservoir thermal modelling

Section II, chapter 3.6 of the application document shows an example of simulated temperature in the P18-2 reservoir at the end of the injection (figure 17). This is, however, the result of extreme assumptions regarding BHT, and is contradicted by all simulations on the effect of rising reservoir pressure on the CO_2 temperature at the well-reservoir interface. While the example serves to illustrate effects on reservoir pressure from post-injection heating of the CO_2, it would be more appropriate to use a more realistic 'worst case' BHT scenario. The worst-case scenarios used in the well injectivity report (B9) and seismic risk evaluation report (B12), on the other hand, never reach BHT much below 60 °C due to the high injection rate and corresponding high BHP. The base case simulations actually reach lower BHT (to about 50 °C) but also inject at lower rates. It is noted in in the well injectivity report (B9) that transient effects on injectivity is not yet taken into account. These could be important for BHT calculation and therefore for injectivity.

We would support further analysis the effect of transient effects. Also, we would suggest a revised discussion in section II, chapter 3.6. Either argue better for the relevance of this 'worst-case' BHT or provide a more realistic 'worst-case' scenario.

Comment: The well injectivity report includes calculations for quite large pressure drops between well and reservoir. Large pressure drops would induce significant cooling of the CO_2. This effect is not discussed together with the injectivity discussion. It is noted, however, that the provided documentation elsewhere, e.g.

B10 flow assurance study, page 17, 82 and 110, assumes that the pressure drop will be low in real operations. As noted above we suggest that the simulated pressure drop between well and reservoir for the base injection cases is presented and discussed with relation to Joule-Thomson cooling in the reservoir. This topic is discussed in literature, also for the P18 reservoirs. See, e.g., Oldenburg, 2006, Mathias et al., 2010 and Creusen, 2018.

From the literature, it seems that the conclusions in the application regarding safety from hydrate formation and injectivity problems are correct. The TNO storage feasibility report (B7, p 51) notes that hydrate formation and its effect on injectivity remains a topic of further research, but that near-well hydrate formation, even if it should occur and lead to reduced injectivity, does not represent a risk for storage safety (B7, p 56). We see no reason to disagree with this conclusion.

4.3 Potential extrapolation of temperature measurements from packer to perforations using OLGA-results?

The local temperatures at the well perforations must be maintained above the hydrate formation temperature to prevent hydrates from clogging the system. And it is also important to accurately know the temperature and pressure at the sandface to calibrate reservoir models.

However, only the temperature at the packer can be monitored during operation. Depending on completion design, the packer will be located a certain distance (15 - 450 meters, as summarized in Table 1) from the perforations and will thus not be fully representative of the perforation temperature. The intention is therefore to amend the measured temperatures using temperature differences predicted by OLGA to obtain the perforation temperature. We cannot see that the expected accuracy of this extrapolation of well temperature is discussed in the application documents.

Comment: A potential major issue with respect to temperature monitoring is the distance from packer to perforations. This issue, and its potential implications, has not been addressed or discussed at all in the technical documentation or application.

Table 1: Summary of some well completion details and packer-to-perforation distance for the P18 wells

Wells	**P18-2A1**	**P18-2A3**	**P18-2A5**	P18-2A6	**P18-4A2**	P18-6A7
Status	planned	planned	planned	back-up	planned	back-up
Reservoir liner	7"	5"	5"	7"	7"	3.5"
Packer (MD)	3560 m	3700 m	4350 m	4405 m	4008 m	4866 m
Perfs (MD)	3575 m	4070 m	4796 m	4488 m	4083 m	4971 m
Distance	15 m	370 m	446 m	83 m	75 m	105 m

A pertinent question is thus: *To what extent can we trust the temperature differences predicted by OLGA?* It is not possible to provide a general answer to this question because there are several thousands of different scenarios to consider. We will however provide some general comments. The relevant temperature calculations in OLGA are a product of many factors, but the following factors are of particular importance:

1) The equation of state for the fluid system.
2) The heat transfer from the surrounding formation.

The applied equation of state is that of pure CO_2, while the actual composition will not be pure. As stated earlier, it is unclear how this will affect the temperature calculations, so we would recommend investigating this matter.

The heat transfer from the surrounding formation is modelled assuming that the temperature of the rock formation layer 12.75 meters from the casing equals the undisturbed geothermal temperature profile. This presumably reflects a situation that will occur after several years of production, where the formation close to the casing has been cooled down by the injected fluids. It is not clear from the document exactly what time scale has been used to come up with the value of 12.75 meters. However, assuming that this time scale covers the lifetime of the system, the prevailing heat flux should be lower than the actual heat flux. This means that the prevailing temperature extrapolation should be pessimistic if we ignore other uncertain factors. However, if the cooling affects a wider region around the well the assumptions in the model could end up give a larger simulated heat flux than in reality. The simulated CO_2 temperature could therefore be higher than in reality. As noted previously, we therefore suggest that the justification for the 12.75 m outer boundary should be investigated.

We can however not state with certainty that other uncertain factors, such as the equation of state, are negligible. Our recommendations on this are therefore as follows:

1) Find from the existing simulation results what the relevant temperature differences are (between the point of measurement and the point of interest). Since the extrapolation distances are relatively short, it may be that the extrapolation does not have a significant impact.
2) If the temperature extrapolation is potentially important, investigate the implications of the applied model simplifications, in particular with respect to the fluid composition.

4.4 Conclusions and recommendations

The temperature behaviour in the well and near-well region is for the most part thoroughly discussed and understood. However, there are several inconsistencies between results from different simulation tools and it is unclear how well integrated the overall approach is.

Furthermore, considering how important it will be to accurately know the temperature at the perforations, it is surprising that the in some cases hundreds of meters of distance from the packer measuring point to the perforations and its potential implications are not addressed or discussed. The OLGA results are reliable, but there are several uncertainties that are not well understood.

Recommendation (major): A more in-depth study of temperature profiles in the bottom part of the well should be performed, with special emphasis on addressing the packer to perforations distance. For example, sensitivity studies of parameters such as thermal boundary conditions, CO_2 purity and injectivity indices, should be included to reduce uncertainty.

5 Leakage consequences in the overburden

As a whole, the application document examines in detail all possible leakage mechanisms, with comprehensive supporting analyses. The risks associated with each mechanism are also well documented. We thus agree with the conclusions arrived at in the application report. However, there are some minor issues that are discussed below.

5.1 Impact of shale in the overburden

A scenario of leakage into the overburden is that CO_2 may be diverted to high permeable formations by sealing clay layers, where shales swell/creep and thus close annuli (Application report, page 194).

We agree that small volumes of leaking CO_2 will probably be absorbed into the overlying aquifers, as reported. However, it should be noted that it is not documented that the P-18 overburden shales creep or form a sealing barrier. It is only commented that these shales are likely to swell, and yes, it is possible that these shales may creep and form a barrier, but this is only an undocumented assumption.

Comment: All creeping shales do not form sealing annulus barriers. The potential use of creeping shales to stop CO_2 leakages is not documented.

A thorough study of the shale formations occurring in the overburden at P-18 could be undertaken to confirm shale creeping/swelling predictions. This study should imperatively include laboratory creep testing (or build on analyses of such tests if already conducted on these rocks) and hydraulic conductivity reduction in hollow cylinder configuration (where annulus pressure can be applied and monitored). The reason for this is that it is still unclear just from mineralogy considerations, which shales lead to creep or no creep under identical stress conditions (Fjær et al., 2016; Brendsdal, 2017; Fjær et al., 2018).

5.2 Leakages through overburden

5.2.1 Geomechanical impact assessment

An assessment of the geology in terms of formation permeability and strength is made to evaluate the risk of failure and creation of a leakage path (report B16 on decommissioning design).

We agree that the presence of multiple sealing formations and high-permeability streaks that can function as spill points make for a negligible risk for leakage through the caprock. A good number of leak-off tests give a reasonable assessment of the fracture gradient in the area of interest and all the wells will be plugged with at least 50 m cement.

When assessing the caprock in terms of strength (Application document, 5.3.2, page 164), the worst case is if tensile stress is predicted to occur, as tensile strength of rocks is an order of magnitude lower than compressive strength. According to simulation results, cracks will not penetrate further than 10 metres into the sealing rock, out of a total minimum thickness of the sealing layer of 450 metres.

Caution must be taken in assessing fracture penetration into shale caprock. Depending on the numerical scheme used for the fracture modelling, the size of the predicted fracture may vary widely. Finite Element codes use different post-failure models to assess which elements turn into "fractured" elements, with reduced stiffness. Only discrete elements codes can then explicitly model fracture aperture growth and propagation, with quantitative prediction of final fracture penetration length. It should thus be justified how the 10 m fracture penetration length was arrived at, since a simple stress change distribution map would not capture stress concentration at the tip which may induce propagation beyond the zone where the background stress values are beyond the shale tensile strength limit.

5.2.2 Leakages along reactivated faults

Only large cooling seems to induce fault reactivation (Application report, page 203). No large-scale fault movement took place. This shows that the mechanical resistance of faults to fault movement in P18 is high, which is an argument to explain the absence of detected seismicity. In addition, during CO_2 injection, the stabilising effect of pressure recovery will be greater than any instability caused. The fault permeability might be enhanced by the stress effects from injection, but the fact that the faults were impermeable (sealing) before depletion forms a barrier against this. Lateral migration is also unlikely because of the extensive faulting of the reservoir. Potential reactivation at end of depletion (B7 storage feasibility main report, page 63): reactivation of faults is depending on the location in the reservoir. Consideration is given for footwall or hanging wall location. Reinjection is interpreted as reversing the situation to stable. Geochemical effects are also discussed in the B7 storage feasibility main report (page 72). A comparison is made to a natural CO_2 seep in Arizona. Temperature effects are discussed in terms of modelling a cooling front. Here, we will only focus on the accompanying analysis looking at stress drops in the overburden (B7 storage feasibility main report, page 75). The analysis is based on Coulomb stress drop and shows that there is no risk of reactivation in the caprock.

This is in agreement with recent simplified modelling of fault stress hysteresis (Rongved & Cerasi, 2019). However, absence of seismicity could be due to fine gouge acting as roller bearing, as noted in acoustic emission lab tests (Park et al., 2021). Also, the structure of the process zone is not taken into account, which may have connecting fractures. There are some statements that are unclear: for example, regarding fault permeability, what about possible stress hysteresis or permanent dilation? After slipping and gaining permeability, usually there is no guarantee of going back to low permeability, except perhaps on a geological timescale. Regarding reinjection reversing: what about possible stress hysteresis or permanent dilation? Again, there is no guarantee of going back to low permeability. However, Rongved & Cerasi (2019) also found that additional fracturing is improbable. The analysis is also conservative in that it does not attribute any cohesion to the fault (the failure line passes through the origin for 0 normal stress). Furthermore, expected weakening or not after exposure to CO_2 is highly dependent on the presence and nature of gouge, at the centre of the considered fault. Finally, looking at stress drops in overburden shale, it is unclear if an anisotropic shale model is taken into account or at least with worst case of mechanical properties (these vary with orientation). Thermal stress properties of shales are complex and different from sandstone (see Favero et al., 2016). It is not clear if this is taken into account, even though we agree that this is probably not a heightened risk.

The Arizona analogue could be discussed in more details in how it differs from P18. For reference, one may look at Gal et al., (2019) and Kloppmann et al., (2021). One mention is the extent of the fault, all the way to the surface, the second is the pressure in the reservoir and the volume of leaking CO_2. The report mentions that the Arizona case is leakage through the damage zone. We would like to see a discussion of, for example, whether there is a risk for creation of a connected damage zone in P18.

5.3 Leakage to surface

5.3.1 Environmental impact assessment of leakage to the surface

An assessment of P&A needs at shallow depths is presented (report B16 on decommissioning design). A well-by-well assessment will be made whether an environmental barrier will need to be placed near surface, the environmental plug should consist of 50 m of cement on a firm base or 100 m without a firm base. This shall be done when there is a risk of environmental pollution by fluids left in the well or if there is rock formation in direct communication with the sea.

Baseline environmental monitoring is included in the monitoring plan in Appendix D of report B7. However, the possible impact of CO_2 leakage on the environment is not discussed. We would have preferred to see a clear plan for conducting a baseline study of the marine environment and assessment of the consequences of different volumes of CO_2 discharged from wells at the sea floor. We also note that reliable baseline monitoring in a marine system such as the North Sea, with large seasonal and annual variations is not a trivial task and should be further elaborated. Please see e.g. the International Journal of Greenhouse Gas Control special issue on CCS and the marine environment, with results from the QICS project (IJGGC Vol. 38, 2015) or the more recent Dean et al., (2020) and Blackford et al., (2021) with results also from other research projects.

Furthermore, a worst-case scenario of leakage to the surface is given in the form of well blow-outs, where all barriers and valves fail, as well as the topside tree (Application report, page 192). It is assessed that for 3 months of uninterrupted free flow, with no depletion of the driving bottom hole pressure, the leak would lead to 112 ktons of CO_2 to be released. (This is the largest mass for the shortest well.) We would have preferred if the technical documentation indicated what the consequences for the sea / atmosphere of such a worst case scenario would be in terms of environmental impact (and economical impact), or clearly indicate that this question is outside of the scope of this application but needs to be planned in further work prior to start of injection operations. For example: How would this compare to baseline variations over 3 months (maybe seasonally varying)?

5.3.2 Monitoring for leakage to the sea

A monitoring plan is established with the following implemented techniques (Application, page 246):

- Gas bubble detection every 2 years;
- Pockmark detection using sonar (ROVs), compared to a reference measurement;
- CO_2 content in seawater samples, taken upon leak suspicion and compared to baseline;
- Seismicity using the national monitoring network.

Baseline may be difficult to establish and may entail a long campaign spanning several seasons or years. Global warming and overall ocean acidification will also have to be taken into account. As already mentioned above in the section on environmental impact assessment, we would have preferred if the technical documentation indicated whether baseline establishment is outside of the scope of this application but should stress that it needs to be planned in further work prior to start of injection operations. Analyses and implementation of such work should build on experience such as published in Blackford et al., (2021).

6 Main conclusions and recommendations

The technical work in the Porthos application is thorough and we agree with the main conclusions. There are some inconsistencies, unclarities and minor issues here and there, which could be addressed for further improvements, but the main conclusions are not affected.

We suggest one major recommendation that should be addressed:

- A more in-depth study of temperature profiles in the bottom part of the well should be performed, with special emphasis on addressing the packer to perforations distance. For example, sensitivity studies of parameters such as thermal boundary conditions, CO_2 purity and injectivity indices, should be included to reduce uncertainty.

Furthermore, we suggest two minor recommendations as well:

- Additional simulations should be performed to determine microannuli formation at the cement-rock interface, as well as to estimate the resulting microannuli apertures and CO_2 leak rates.
- Consider using DAS in non-active injection wells as part of microseismic and/or seismic monitoring.

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Appendix: List of available documents for review

Main application document:

Application for a CO_2 storage permit reservoir P18-2

- Section I: Framework for the Application for a CO2 storage permit reservoir P18-2
- Section II: Description of CO2 Storage reservoir P18-2
- Section III: Risk Management Plan for the Integral P18 storage complex
- Section IV: Monitoring Plan for the Integral P18 storage complex
- Section V: Corrective Measures Plan for the Integral P18 storage complex
- Section VI: Closure Plan for the Integral P18 storage complex

Technical documentation (Bijlagen):

- B7 CO2 storage feasibility in the P18-2 depleted gas field (TNO, 2019)
- B8 Storage Capacity Technical note (Porthos, 2020)
- B9 P18 Porthos well injectivity (Porthos, 2020)
- B10 Flow Assurance Study FAS report (TNO/Porthos, 2021)
- B11 Injection plan Porthos (Porthos, 2021)
- B12 P18 CCS: Seismic Risk Evaluation (Fenix, 2021)
- B13 Well containment note (Porthos, 2020)
- B14 P18 Core Test Evaluation (Fenix, 2020)
- B15 Porthos Basis of completion design (TAQA, 2019)
- B16 Porthos Basis of decommissioning design (TAQA, 2019)

Additional documentation:

- B. Willemsen (2020). 4D Screening Porthos
- Geophysical Evaluation P18 report (TAQA, 2018)
- P18 Slugging study for CO2 transport through pipeline to P18 platform (TNO, 2020)

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