CATO-2 Deliverable WP 3.4-D18:
Design Specifications of Well Integrity Tests

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1 Executive Summary (restricted)

This deliverable discusses potential mechanical integrity issues that may occur during CO_2 storage process, and mechanical integrity tests advised by United States Environmental Protection Agency (USEPA) for Class VI CO_2 injection wells. In addition, another well integrity test that aims to assess the effective permeability behind the casing is introduced and reviewed in more detail.

For a successful CO_2 storage operation, it must be ensured that the injected CO_2 remains in the target formation. In order to achieve this, especially the integrity of all relevant wells must be confirmed and monitored throughout the project. During injection and the subsequent phases of CO_2 storage, leak paths may be created in wells due to poor cement condition, chemical and mechanical loads and/or equipment failure. The injected CO_2 is detrimental to both cement and completion equipment such as tubing, casing and packers; leading to an increased chance of well integrity issues. Potential leak paths that can be observed in a well are leaks through casing, leaks through interfaces between cement, steel and the formation and leaks through channels created in the cement sheath.

In order to ensure that the well integrity is maintained, various well integrity tests must be carried out frequently throughout the project. Well integrity tests are classified into two groups by USEPA; internal mechanical integrity tests (to check for fluid flow through casing and other completion items) and external mechanical integrity tests (to check for fluid flow through channels in cement). Mechanical integrity tests are initially performed prior to injection, and then repeated periodically until abandonment.

Internal mechanical integrity tests consist of annulus pressure testing and radioactive tracer surveys. Annular pressure testing coupled with annulus pressure monitoring is the desired internal well integrity testing strategy for most wells. Continuous annulus pressure monitoring is also advised during injection, as sudden pressure changes is a direct indication of a problem in internal well integrity.

External mechanical integrity tests discussed by USEPA are limited to various logging methods, namely noise logs, temperature logs and oxygen activation logs. Integrity testing by temperature logs is based on the notion that a leak will result in a temperature anomaly around the wellbore. Therefore, this method can be considered as both an internal and an external well integrity test. However, these logs are ineffective in gas filled wells due to lack of thermal coupling, and are thus unsuitable for most CO_2 injection and monitoring wells (depends on injection parameters).

In addition to the completion of operating wells, the integrity of abandonment plugs that are installed in legacy wells have to be tested before injection if the wells could be affected by the storage operation. Integrity tests for abandonment plugs are usually carried out as quickly as possible, but have to regard specifications of each abandonment plug. The mechanical integrity of an abandonment plug can either be tested by a pressure test or a weight test after the well has been re-entered, which can be challenging.

An external mechanical integrity test that is not based on logging can be performed by a permeability test. Performed post-injection and prior to abandonment, the test is carried out by perforating two small intervals in the well, and then by isolating the test interval and applying pressure on the casing. The permeability behind the casing is measured by the pressure response in the perforated intervals. In order to quantify the effective permeability, a test-specific numerical model and several simulation runs are required. The effective permeability is determined by matching the simulations to physical test results. Depending on the results of the test, cement squeeze over the interval and repair of the perforated casing may be required.

Distribution List

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Document Change Record

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Version	Nr of pages	Short description of change	Pages

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2 Applicable/Reference documents and Abbreviations

2.1 Applicable Documents

(Applicable Documents, including their version, are documents that are the “legal” basis to the work performed)

	Title	Doc nr	Version
AD-01d	Toezegging CATO-2b	FES10036GXDU	2010.08.05
AD-01f	Besluit wijziging project CATO2b	FES1003AQ1FU	2010.09.21
AD-02a	Consortium Agreement	CATO-2-CA	2009.09.07
AD-02b	CATO-2 Consortium Agreement	CATO-2-CA	2010.09.09
AD-03h	Program Plan 2014	CATO2-WP0.A-D03	2013.12.29

2.2 Reference Documents

(Reference Documents are referred to in the document)

	Title	Doc nr	Version/issue	Date
Kolenberg et al (2012).	Evaluation of current logging tools and industry practices for material selection and repairs	CATO-2 Deliverable WP3.04-D15		
Zhang and Kermen (2014)	Specifications and design criteria for innovative corrosion monitoring and (downhole) sensor sytems, including sensitivity analysis	CATO-2 Deliverable WP3.04-D16		
Kermen and Meekes (2013)	Monitoring Strategies for Inaccessible/Abandoned Wells	CATO-2 Deliverable WP3.4-D17		
Hangx et al. (2013)	Coupled geochemical-geomechanical experiments on wellbore cements	CATO-2 Deliverable WP3.04-D21		

2.3 Abbreviations

(this refers to abbreviations used in this document)

3 Introduction

When a potential site for Carbon Capture and Storage (CCS) is evaluated in an area where drilling has taken place, e.g. for oil and gas production, geothermal energy or solution mining, one of the essential steps of ensuring the integrity of the CO_2 storage location is to assess all wells that might come into contact with the CO_2 in the target formation. The evaluation process may take several years, during which a database of all relevant wells (materials and history) is constructed, operations for well barrier evaluation such as logging and remediation are performed and well integrity tests are carried out to confirm that the area will be suitable for CO_2 storage. An accurate and precise evaluation process is essential to carry out a safe and successful CCS operation.

Another essential part of CO_2 storage is maintaining well integrity throughout the life of the project, and for many more years after the project has been completed. Under typical downhole conditions, CO_2 can lead to casing corrosion and cement degradation. In order to confirm that the well integrity is maintained, mechanical integrity tests (MIT's) are carried out throughout the project.

4 Well Integrity

One of the main aspects of CO_2 storage is to ensure that the CO_2 injected in the target formation, remains in the target formation. Potentially, every wellbore penetrating the target formation may present a leak path for CO_2. During and after injection, the CO_2 plume may move upwards or sideways in the storage formation or may even escape through potential leak paths. Leak paths may be generated due to poor cement sheath or failure of completion items (casing, tubing, packer). Furthermore, the corrosive nature of CO_2 combined with additional stress regimes related to injection increases the possibility of leak path creation.

According to NORSOK D-010, well integrity is “an application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well” (NORSOK 2013). Demonstrating and maintaining well integrity is essential to prevent (or minimize) the movement of CO_2 outside of the target formation. This is achieved by careful well design and material selection followed by the implementation of a monitoring program, in which well integrity is evaluated continuously through tests. The regularly updated monitoring program must span throughout the project life cycle and beyond to ensure safety.

4.1 Leak Paths

Potential leak paths associated with CO_2 storage in a cased wellbore are displayed in Figure 1. CO_2 may leak along the interface between cement and the casing, through the pores and fractures in the cement or the interface between the cement and the formation. Additionally, CO_2 corrosion may damage the tubing or casing, and result in the creation of additional leak paths.

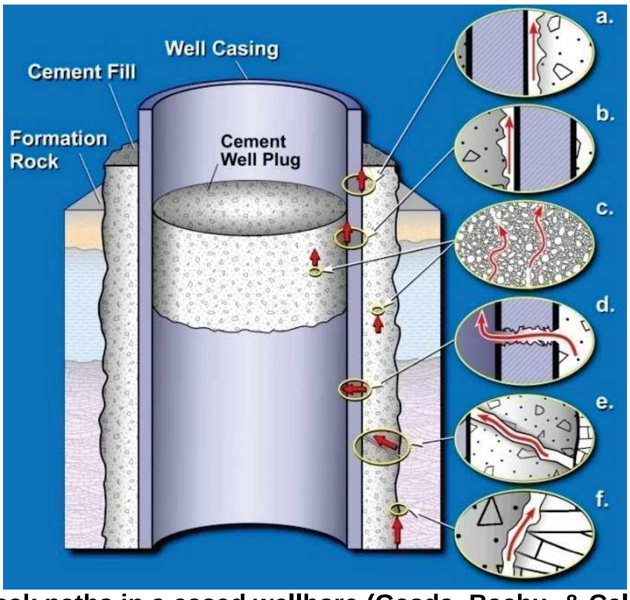

Figure 1. Potential leak paths in a cased wellbore (Gasda, Bachu, & Celia, 2004)

Presence of CO_2 also causes cement degradation which can result in the formation of several zones within the cement with varying porosity / permeability and a decrease in mechanical strength. (Hangx et al, 2013, CATO deliverable WP3.04-21). Cement degradation can increase the leak potential through the cement sheath. The rate at which cement degradation occurs depends on temperature, cement types and composition, water / cement ratio, moisture content, CO_2 partial pressure, and porosity or permeability (Kutchko, et al. 2007; Santra, et al. 2009).

Leak paths through the cement sheath may result both from poor execution or changing wellbore conditions. A review of mechanical factors influencing wellbore cement sheath integrity revealed that fractures in the cement sheath can occur due to cement de-bonding and fracturing at the rock -formation interface caused by water activity in the shale and cement (Randhol and Cerasi 2009).

Insufficient removal of the filter-cake or mud prior to cementing operations may result in channelling to occur throughout the cement resulting in the creation of (micro)annuli in the cement sheath. Another factor that may influence the creation of leak paths through the cement is cement shrinkage. All standard cement classes tend to shrink about 5% (Kermen and Meekes 2013). Cement shrinkage causes circumferential fractures behind the casing (Dusseault, Gray and Nawrocki 2000). In order to prevent the effects of cement shrinkage, additives and fibers are added to the cement slurry.

Similar to cement degradation, casing corrosion significantly reduces well integrity, and may induce additional leak paths. The rate of corrosion depends on the temperature and partial CO_2 pressure. Under reservoir conditions, corrosion rates higher than 10mm/year for carbon steel have been reported (Brondel, et al. 1994). In an injection well, the casing is protected by injection tubing set as deep as possible in the well. Meanwhile, the integrity of the tubing can be evaluated by annular pressure monitoring and wellbore logging methods (Figure 2).

During injection, changes in temperature and pressure will lead to stress exposure in the injection wells. Potential deformation caused by uplift of the reservoir during injection may rise to deformation loads on casing and cement, and possible fractures (Orlic and Benedictus, 2008).

5 Mechanical Integrity Tests

In 2013, USEPA listed several mechanical integrity tests as part of the Underground Injection Control (UIC) Program (USEPA 2013). According to this program Mechanical Integrity Tests (MITs) are required prior to injection, during injection and prior to plugging and abandonment after the injection is stopped. MITs aim to assess well integrity by providing information about fluid movement within and around the well and determine whether any leaks are present in well completion items or through the cement sheath behind the casing. The tests offer a wide range from straightforward pressure tests to several wireline logging methods.

USEPA differentiates mechanical integrity into two categories, internal mechanical integrity and external mechanical integrity. A well has internal mechanical integrity, when there is no significant fluid movement in the injection tubing, casing or packer, and a well is considered to have external mechanical integrity if there is no significant fluid movement through the cement sheath. The figure below displays three instances where the well integrity has been lost (Figure 2).

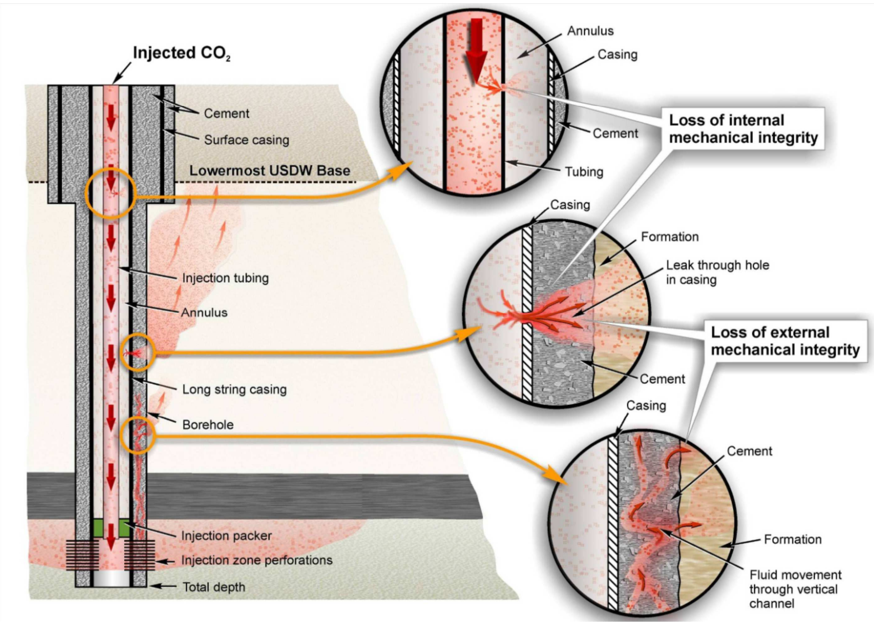

Figure 2. Three scenarios where the well mechanical integrity has been lost; the top example shows a leak in the tubing (loss of internal mechanical integrity); the middle example shows a leak in the casing (loss of internal mechanical integrity) and fluid seepage through the cement and into formation (loss of external mechanical integrity); the bottom example shows fluid movement through channels in the cement sheath (loss of external mechanical integrity) (USEPA, 2013)

5.1 Internal Mechanical Integrity Tests

Internal MITs are carried out to confirm the mechanical integrity of well completion items such as tubing, casing and packers. The most common internal MIT is the annulus pressure test. In addition to MITs, monitoring certain parameters throughout the project is also an important part of maintaining internal mechanical integrity. Parameters such as injection pressure and rates, annulus pressure and fluid volumes must continuously be monitored in order to ensure integrity.

5.1.1 Annulus Pressure Test

The annulus pressure test is the most common and effective method of confirming internal mechanical integrity. It involves increasing the pressure within the annulus to a specified level and subsequently monitoring the annular pressure for a set period.

The UIC program states that the annulus pressure test is required prior to commencing injection through a Class VI well. The test is first carried out after the well has been constructed and all well logs have been conducted (USEPA 2012).

The annulus pressure test is based on the principle that pressure applied to fluids filling a sealed vessel, in this case the annular space, will remain unchanged. If loss of internal mechanical integrity detected, action may be required to remediate leakage pathways in the injection tubing packer or casing prior to the commencement of injection.

Prior to conducting the test, the injection tubing and annulus are completely filled with fluid; the annulus filled with the non-corrosive completion fluid of sufficient weight, while the injection tubing is filled generally with CO_2 slurry (during injection) or water. In order to eliminate temperature effects, the well must be allowed to reach thermal equilibrium prior to the test (Kansas Department of Health and Environment 2012). The presence of any additional substances, that are not approved by regulatory bodies (i.e. any other substance than annular fluid and the fluid injected to exert additional pressure), in the annulus might affect the outcome of the test, and can therefore invalidate the test. For an effective test, the pressure must be transmitted through the entire wellbore. Therefore, no mechanical plug may be placed above the packer for the annulus pressure test.

After thermal equilibrium is achieved, the annulus is pressurized to the test pressure. The appropriate test pressure is dependent on several factors such as well depth, formation pressure, fluid densities and the anticipated injection pressure. Factors such as casing burst pressure and casing expansion must also be taken into account when determining the test pressure. Given that the casing can withstand it, it is advised to test the annulus to a pressure higher than the maximum injection pressure in order to ensure a leak in the tubing will not induce damage on the casing.

After applying test pressure, the annulus is isolated from the pressure source. This is usually achieved by a closed valve or by simply removing the pressure source. The pressure is then continuously monitored for the duration of the test. The test duration must be long enough to allow the pressure to stabilize, but short enough to minimize temperature effects. Tests lasting between 15 minutes and one hour are advised (USEPA 2012).

Changes in annulus pressure during the monitoring period may indicate loss of mechanical integrity. However, due to heat transfer, small pressure changes not indicative of leakage may occur during the test. Failure of the pressure to stabilize during the test period or a change in pressure above the acceptable margin indicates a failure to demonstrate mechanical integrity. Typically, the margin of acceptable change in pressure varies between three and ten percent (USEPA Region 5, 2008). More commonly, 5% is used as the acceptable threshold (Kansas Department of Health and Environment 2012).

In case of a failed annular pressure test, the pressure response during the test may indicate where the leak might have occurred. Under operating conditions, the pressure inside the injection tubing, the annular pressure and the pressure of the injection zone would be different, and a large enough leak may induce a pressure response that would indicate where in the well the loss of integrity has occurred. When a leak is suspected, wireline logging will be carried out to pinpoint the leak in any case.

For accurate measurements, the pressure gauge used to monitor the annular pressure must be sensitive enough to detect any pressure changes that would result in a failure of the test. After the test period, the fluid used for the pressure test must be collected back and measured. A change in the amount of returned fluid may indicate whether the entire wellbore has been tested.

5.1.2 Annulus Pressure Monitoring

To ensure well integrity, annulus pressure must be monitored continuously at all times during CO_2 injection. Significant changes in annulus pressure measured during injection may indicate a loss of internal mechanical integrity.

Similar to the annulus pressure test, annulus pressure monitoring must be carried out using a gauge sensitive enough to detect any pressure changes that would indicate a loss of mechanical integrity. Unlike pressure tests, interpretation of continuous annulus pressure data is more complex due to many effects related to the injection process such changes in temperature and injection parameters. In the event of a casing leak opposite a permeable zone, the pressure will normally drop to pore pressure of the permeable zone. If that is not the case the pressure change will be minimized as the communication between aquifer and the leak nullifies the effects of volumetric changes in the annulus. In the event of a tubing or packer leak, the annulus pressure will mimic the injection pressure. However, it is unlikely for these pressures to be equal due to pressure losses is the injection tubing and density differences due to temperature effects.

A leak may not always be evident through monitoring if it does not trigger a significant pressure change. To improve the possibility of detecting a leak, it is advised to measure and monitor the volumes in the annulus system. A simple way to monitor the volumes in the annulus system is to record/measure all fluid additions/removal from the annulus. A continuous need to add or remove fluid to/from the annulus to maintain pressure is an indication of a leak. When an indication of a leak is observed, an annulus pressure test must be carried out to confirm the presence of a leak.

5.1.3 Radioactive Tracer Surveys

Radioactive tracer surveys are regarded as the only alternative to annulus pressure tests to test the internal well integrity. However, they are not commonly preferred due to the long duration required for testing. The main advantage of radioactive tracer surveys over pressure tests is that these surveys provide means to pinpoint the depth of a leak in the casing.

Radioactive tracer surveys are carried out using wireline. The wireline tool consists of a pump unit with a reservoir where the radioactive injectate is stored, one or more gamma radiation detectors and a Casing Collar Locator (CCL). In order to increase the accuracy of the tests, multiple detectors are preferred. The CCL is required to determine the depth of a leak in reference to casing collars. An anionic tracer material is ideally preferred in order to minimize molecular interaction with the well and the formation. Iodine-131 is a commonly used tracer, mainly due to its short half-life of 8 days and reasonable cost.

A radioactive tracer survey is carried out by releasing tracer into the tubing, above the interval to be tested; and by measuring gamma radiation as the tracer travels within the well. The survey can be carried out in two ways. In the first one, the wireline tool is moved within the well in order to detect the position of the tracer (slug test). The second method is called the velocity shot. During this survey, the wireline tool is kept stationary, and the time that the tracer slug passes through the detector(s) is monitored. As the tracer material moves through the well with the injectate, the gamma ray detector(s) will detect a sustained increase in radioactivity in the presence of a leak, even after the injectate has moved away from the detector. In order to determine the gamma radiation anomalies, it is imperative to carry out a base log prior to the release of the tracer. It is common practice to conduct the test during injection, and it is advised to maintain an injection rate as high as practical during the test (USEPA 2013).

5.2 External Mechanical Integrity Tests

The objective of external MITs is to detect significant fluid movement behind the casing. The external mechanical integrity of every injection well must be confirmed upon well completion, and prior to the start of the injection. It is advised to repeat tests periodically until abandonment. Available external MIT methods are indirect measurements consisting of several different logging methods.

5.2.1 Noise Log

Cement channels are generally formed at random in the cement sheath. Due to the non-uniform nature of these channels, turbulences are generated as fluid moves through the cement. These turbulences can be picked up by sensitive microphones. Noise logging is a wireline method, where the turbulences due to fluid movement behind the casing are measured by downhole microphones.

Measurements are carried out via taking noise samples at intervals. It is recommended to have maximum 100ft intervals between two samples, but finer grids can be used to increase resolution (USEPA 2013). For accurate sampling, the tool must be stationary during measurements. Each sample takes approximately 3-5 minutes to be completed. The noise is detected by the microphones, and then transmitted to recorders that measure the noise level.

A base log is essential for accurate interpretation. Fluid measurement behind the casing can be detected from anomalies in the noise level in comparison to the base log. The zone of fluid movement can be pinpointed by sampling in smaller depth intervals (depending on the tool, can be as small as 1-3 ft) around the location where the maximum anomaly is detected. If a lack of external mechanical integrity is detected, remediation will be required.

Noise logs are a highly sensitive method to detect anomalies. Stationary measurements are required to avoid unexpected noise due to friction. Regardless of how the logging is performed, noise from the surface may present a problem during measurements at shallow depths. When applied successfully, gas percolation rates as small as 10 ft^3/day have been reported (George E King Consulting, 2014).

Noise logging can usually be performed simultaneously with injection, as the flow restriction caused by the wireline tool is in most cases negligible, and does not cause an audible turbulence. However, in such cases it is advised to have a base log conducted under injection conditions to easily filter out noise related to injection activities.

5.2.2 Temperature Log

Temperature logs are based on the principle that fluid leaking from the well will cause a temperature anomaly adjacent to the wellbore. Fluid leaking from the well will usually be of a different temperature than the geothermal conditions at the location of the leak. This will cause the temperature of the formation in the vicinity of the leak to change (in most cases, a cooling effect is observed), resulting in a temperature anomaly (Figure 3). Temperature logs can also confirm lack of leak paths in the formation behind the casing, and can often identify small casing leaks as small as 10-15 l/hr. The sensitivity of the tool is dependent on the initial temperature difference between the injection tubing and the annulus.

In order to eliminate temperature effects related to the movement of the injectate through the well, the well needs to be shut-in long enough for temperature effects to dissipate prior to conducting a temperature log. Experience has shown that 36 hours is usually a sufficient shut-in period (USEPA Region 5 2008). During the shut-in period, the temperature within the wellbore will change towards geothermal conditions. Logging is performed at short intervals (10 – 50 m) throughout the entire wellbore. In order to increase the accuracy of the measurements, it is advised to move the tool slowly in the wellbore. Most thermal sensors are not sensitive enough to react instantaneously to temperature changes, and the measured temperature changes lag behind actual wellbore values. By reducing the speed, this effect is minimized. If the tool speed is erratic, the recorded temperature profile will also be irregular. Despite the possible inaccuracies due to poor calibration and tool response time, the absolute values recorded can generally be compared with some confidence.

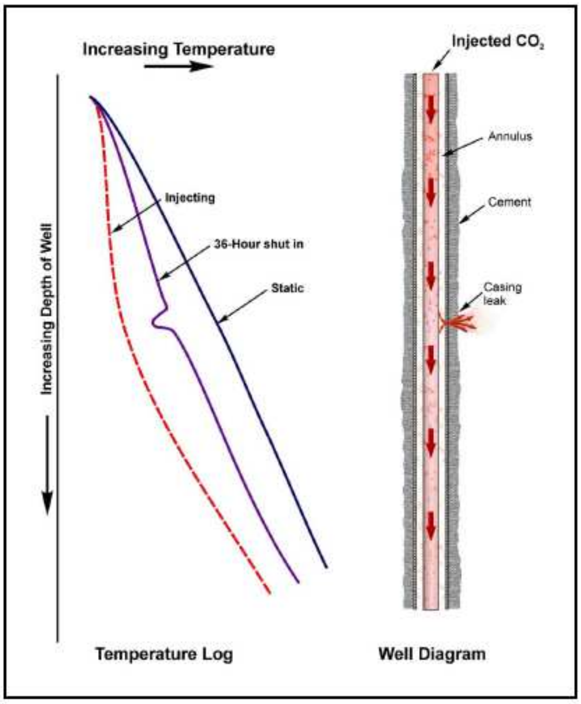

Figure 3. Sample Temperature log showing a leak on the casing (USEPA 1982)

For accurate measurements, good thermal coupling between the wireline tool and the wellbore is required. As a result, the accuracy of temperature logs in gas-filled wells is limited. In a CO_2

injection well, the efficiency of temperature logs will be dependent on the injection conditions. Using fiber optic temperature sensors may also reduce effects of poor thermal coupling.

Similar to all logging methods, a base log is required to detect anomalies in the temperature. Due to the long lasting temperature (several weeks to months) effects related to the continuous circulation of drilling fluid, the base log must be carried out as long as possible after the drilling of the well and prior to the start of injection operations. In addition, temperature logs carried out in other wells on the same injection site may also assist in the interpretation of the results. Even though the responses from different wells will not be identical, the thermal effects due to lithology will in most cases show a similar trend; with the assumption that the lithostratigraphy within both wells is also similar. Deviations from the general trends may point out to well integrity issues in such cases.

5.2.3 Oxygen Activation Log

Oxygen activation log is a wireline logging method that is used to detect water movement in a borehole or behind the casing. Oxygen atoms in water can be activated into nitrogen-16 isotopes by emitting high-energy neutrons from a source. This isotope then decays back to oxygen with a half-life of 7.1 seconds. About 69 percent of the decay path is accompanied by gamma radiation which easily penetrates well completion, cement and fluids (Bernard 1995). The resulting gamma rays are counted, and the velocity of the water flow is estimated from this count by timing the change in gamma radiation between multiple detectors that are apart at known distances. Depending on the location of the detector, the direction of flow can also be measured (detector above neutron-generator for upward flow, detector below neutron-generator for downward flow). The logging tool for oxygen activation logs contains a neutron generator and multiple gamma ray detectors. Typically, the detectors are located at different distances from the source for increased accuracy during interpretation. Gamma ray measurements taken from at least two detectors can be used to calculate the flow velocity and direction.

Unlike temperature logs, this method requires little to none shut-in period. Furthermore, a liquid-filled wellbore is also not required in order to conduct the logs. The main disadvantage of this method is the limited range of investigation that limits the accuracy to detect fluid movement behind 2 strings of tubulars. Additionally, the vertical resolution of the method is limited to a few meters. For more accurate results, it is recommended to maintain injection pressure as close to maximum as possible during logging. Studies and field experience reveal, that oxygen activation logs can detect fluid movement ranging from 2 to 120 ft/min (USEPA, 2013).

Due to the presence of oxygen containing materials / fluid in the wellbore, a calibration log, conducted when there is no flow, is required prior to measurements to establish the background radiation level. It must be stressed that the background noise does not have a definite quantity, and may change between the calibration log and the measurements, increasing the uncertainty of interpretation. The duration of the test is an important factor to achieve accurate results. Sufficient time for activation is required for increased accuracy; however a too long activation period may result in losing a part of the signal. The activation time is dependent on well conditions such as injection rate and pressure.

False positives, which are the false indication of channels behind the casing, are a common artefact of oxygen activation logs. In order to avoid false positives, it is recommended to confirm all indications of flow at multiple depths. Another way to confirm flow paths is to repeat measurements with different injections rates, and confirm if flow is present with all.

5.3 Mechanical Integrity Tests for Abandonment Plugs

Once CO_2 injection operations have been completed, the injection well will be abandoned by placing several abandonment plugs in the well (the number of plugs is dependent on the well configuration and mining regulations at the time of abandonment). For a CO_2 storage site, these plugs will either be cement plugs or a combination (cement placed on top of mechanical plug). Regardless of the type of the plug, its mechanical integrity must be confirmed after installation to serve as a barrier. In the case of a combination plug, the integrity of the mechanical plug and the cement plug must be tested and confirmed separately. The mechanical integrity of a barrier may be tested either by a pressure test from surface or by a weight test.

The pressure test to confirm mechanical integrity of abandonment plugs is the most common method used in the industry (CSI Technologies, 2011). The test is very similar to the annulus pressure test. After the plug has been installed, a fluid (non-corrosive to metal and non-detrimental to cement) is injected into the well above the plug to apply pressure on the plug. Once the testing pressure is reached, the pumps are stopped, the well is shut-in and the pressure is monitored. The mechanical integrity of the plug is confirmed if there is no pressure decrease observed during the pumping period, and if a stabilization of the pressure is observed during the monitoring period. While the duration of the monitoring period and the maximum test pressure will be dependent on the well and plug configuration, minimum acceptable criteria are specified by regulatory bodies. A failed pressure test does not necessarily point out to a leaking plug, as the failure may have been caused because of problems in the casing integrity. Additional testing and measurements may be required in case of a failed test to confirm where the failure occurred. Typically, the maximum test pressure will be the maximum expected reservoir pressure or higher, while ensuring the test pressure does not exceed the burst conditions of the casing. Similar to the annulus pressure test, the duration of the monitoring period has to be long enough to observe pressure stabilization, but short enough to eliminate temperature effects (typically 15 minutes to an hour). According to Dutch Mining Regulations, the minimum acceptable criterion is 50 bars for 15 minutes (Kermen and Meekes, 2013).

The principle of the weight test is simple; a workstring of certain weight is lowered into the hole, and the weight of the string is then exerted on the plug to confirm that it can structurally withstand the weight. The workstring is initally run in the hole to tag the cement plug. After the plug is successfully tagged, the weight of the string is slacked off to apply pressure on the plug. The integrity of the plug is confirmed if the string does not move within the plug. In order to have a successful weight test, it is essential to wait sufficient amount of time (as suggested by lab tests) for the cement to harden prior to the test. If the test is carried out under conditions where the cement is not hardened, the string will move in the cement, and will induce the risk of losing the string in the well due to hardening of the cement. Therefore, it is advised to pull out the string as quickly as possible in the event of a failed test to confirm the failure is not due green (unhardened) cement The weight applied on the plug is dependent on the weight and the size of the string as well as the fluid in the well at the time of the test. Ideally, the string has enough weight to exert more pressure on the plug than the maximum expected pressure. In Dutch Mining Regulations, the minimum weight to be applied has been defined as 10250kg (equivelant of 100 kN force) (Kermen and Meekes, 2013).

The pressure test is the preferred method of testing as it verifies the sealing integrity of the plug with regard to fluid movement. Furthermore, the pressure test can be applied under any circumstances, while the weight test can only be applied when the section to be tested is long enough to accommodate a workstring of sufficient weight. The main drawback of the pressure test is the failure to locate the location of the plug after installation (top of cement). In order to ensure the plug has been set correctly, the plug must be tagged with either wireline or a workstring before it has been pressure tested. If not set at the correct interval, the plug may have to be replaced.

Dutch Mining Regulations also allow a third method called inflow testing to confirm the integrity of a abandonment plug. An inflow test is performed by decreasing the hydrostatic head above the plug to a value lower than the pressure acting on the plug from below. The integrity of the plug is confirmed if no flow from the formation into the well is observed on surface for the duration of the test. Inflow tests are not considered mechanical integrity tests, and are outside of the scope of this deliverable.

6 Permeability Tests

In 2009, Crow et al. tested the integrity of a CO_2 producer using different methods, including sampling and laboratory tests. One of the methods was called a vertical interference test (VIT), where the effective permeability of the barrier systems behind the casing between two perforated intervals was investigated (Crow, et al. 2009). During the test, the barrier system in question consists of the cement sheath behind the casing, the formation behind the cement which may have been damaged during drilling activities and any microannuli and channels within the cement. As this method provides a direct measurement of the cement permeability, a test of similar setup would be an ideal well integrity test for a well associated with CO_2 storage, especially a CO_2 injection well.

6.1 Test Setup

The vertical integrity test is essentially a modified form of the casing pressure test. The test is performed by exerting pressure on the casing, and analysing the response to this pressure increase behind the casing. In order to investigate the external mechanical integrity, an access point behind the casing must be established. These access points can be generated by perforations. For tests conducted in the injection zone, these perforations may be a part of the original well completion.

The pressure response is measured using a specifically designed wireline tool. In order to conduct the test accurately, the wireline tool must provide zonal isolation and must contain multiple pressure gauges. Zonal isolation can be achieved by packer systems mounted on the wireline tool. A packer is placed just below the top perforations to isolate the casing, and a second packer is placed below the bottom perforated zone. To measure the pressure response through both perforations, pressure gauges are located adjacent to each perforated interval (Figure 4). As pressure on the casing above the top packer is increased, both the applied pressure, and the pressure response in the bottom perforated interval is measured and recorded.

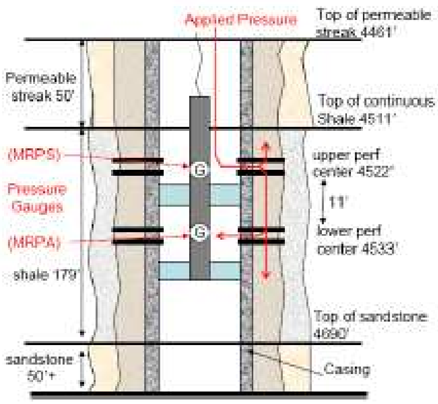

Figure 4. Downhole configuration of VIT tool (Crow, et al. 2009). During applications in 2009, different pressure gauges have been used for the top (straing gauge) and bottom (quartz gauge) perforated intervals

The test will be continued until a stabilized pressure response is recorded on the lower gauge. The test duration is dependent on wellbore conditions and the duration between the perforated intervals as well as the permeability of the cement sheath. As a reference, during measurements in 2009, the test duration was 10^4 seconds (ca. 2.75 hours) after application of pressure on the casing over a test interval of 11 feet (3.35 m) (Crow, et al. 2009).

6.2 Interpretation

In order to interpret the results of the test, initially the data is normalized to a dimensionless scale between 0 and 1, where a value of 1 indicates that 100% of the pressure change imposed on the top perforation is observed on the lower perforation. The data is normalized by taking the ratio of the relative pressure changes recorded in both pressure gauges using

$$p_{norm} = \frac{p_{lower\ gauge}(t) - p_{init\_lower\ gauge}}{p_{\max\_upper\ gauge}(t) - p_{init\_upper\ gauge}}$$

The normalized data is used to quantify the degree of connection between the perforated intervals. To quantify the effective permeability behind the casing, a numerical model is required to simulate physical test data. The governing equation for the numerical model is the continuity equation for compressible flow of a single fluid in porous media

$$c_f \frac{\partial p}{\partial t} - \nabla . \frac{k}{\mu}(\nabla p - \rho \vec{g}) = 0$$

where c_f is the compressibility (1/Pa), p is the fluid pressure (Pa), k is the permeability (m^2), μ is the fluid viscosity (Pa.s), ρ is the fluid density (kg/m^3), and $\vec{g}$ is the gravity vector (m/s^2) (Crow, et al. 2009). The numerical model is constructed based on well information, and solved for different cases. The solutions are compared with the test results, and effective permeability value that best matches the test data is determined. Once the effective permeability behind the casing is determined, the extent of the damage in external mechanical integrity can be evaluated. Depending on the severity of the damage, remedial action will be initiated to prevent vertical migration of CO_2 behind the casing or the seepage of CO_2 out of the wellbore into (permeable) formations.

6.3 Discussion

As the interpretation of the permeability test depends on the quality of the numerical model, it is essential that the numerical model represents the downhole conditions as accurately as possible. Therefore, it is required that realistic parameter values, such as formation permeability and compressibility during numerical analysis, are used. Accurate data on downhole conditions can be gathered by an analysis of drill cores and side-wall cores. Additional information on geology and lithostratigraphy can also be incorporated in the numerical analysis to obtain more accurate results.

It should be noted that the structure of the numerical model used for interpretation will be specific to each well and very likely, to each permeability test. Depending on the distance between the perforated intervals, it is very possible that the fluid viscosity and density will be assumed to be constant in the numerical model. The temperature effects on viscosity and density will be negligible over small distances. This will create a system that is dependent on only two variables (compressibility and permeability), simplifying the equation to be solved. The initial and boundary conditions of the numerical model, along with the number of grid blocks used to construct the model also influence model accuracy. The grid block size must be as small as possible to include the effects of known artefacts, such as loss of integrity (e.g.: patchy cement observed from cement bond logs or perforations) and anisotropy, in the model. Under regular conditions, the outer boundary in the vertical direction will be a no-flow boundary imposed by the casing, while the initial condition at the other end will be hydrostatic pressure from the adjacent formation.

While the vertical integrity test may give significant information about cement permeability and integrity, it should be noted that in practice it can only provide information about a small section of the cement sheath, as a test over long intervals will need a very long time for the pressure response to stabilize. Furthermore, these tests can only be implemented easily at the target zone below the injection tubing. In a typical CO_2 injection well, the injection tubing will not be cemented, but cement will be placed around the casing enclosing the tubing (Figure 5). In a well with a similar configuration, a vertical integrity test above the target zone will be a complex and expensive operation because it will require the injection tubing and the packer to be removed to gain direct access to the casing and to prevent damage to the well completion.

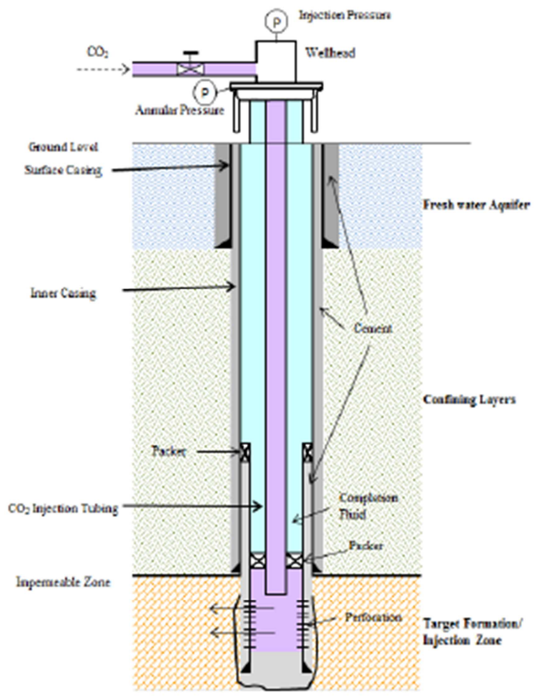

Figure 5. A typical CO_2 injection well configuration (Zhang & Kermen, 2014).

In addition, the test requires the casing or liner to be perforated, which will create a leak path in the system. Even though this damage will later be remedied by squeezing cement, this operation will not guarantee that the well integrity is restored. In order to contain the potential damage to the well and to prevent migration of CO_2 to permeable layers, the vertical integrity test must be confined to the injection zone and the caprock. Since an intentional damage to the well integrity during the injection period may lead to serious well / formation integrity problems (especially when in combination with additional integrity issues), the most suitable time to carry out the vertical integrity test is prior to the abandonment of the well.

7 Conclusions

One of the most important factors in a successful CO_2 storage operation is maintenance of well integrity throughout the life time of a well. Seepage of CO_2 through leak paths in the well and cement due to well integrity issues will have environmental and financial consequences on the success of the operation.

Well integrity tests are used to validate and maintain well integrity. These tests are carried out initially upon well completion, and are then repeated frequently through different project phases to (re-)confirm well integrity. Well integrity tests are not specific to CO_2 injection and monitoring wells, and are widely used in most production and injection wells throughout the world. Should the tests indicate the well integrity is compromised, and remedial action may be deemed necessary.

Integrity tests can be separated into those that test internal mechanical integrity (casing, tubing and packer leaks) and those that test external integrity (leaks behind the casing mainly due to poor cement condition). Due to its simple application, short duration (a few hours including setup) and ease of interpretation, annulus casing pressure test is the most commonly preferred method of testing internal mechanical integrity. Annulus pressure test is also the most economical internal integrity test, as it does not require additional wireline tools to be run in the well. The sensitivity of the test will be dependent on the initial difference between the injection tubing pressure and the annulus pressure. In the case of a failure, the pressure response gathered during the test may be indicative of the location (from measured pressure) and size (from rate of response) of the failure. However, additional wireline measurements will be required in the case of a failure to investigate the nature of the leak, and take necessary remedial actions.

In addition to separate tests, it is required in injection wells to continuously monitor casing pressure during CO_2 injection, as most internal leaks will induce a rapid pressure response on the casing pressure. Since some small sized leaks may not trigger a pressure response, it is also advised to measure any fluid added to or taken from the annulus during operations. Furthermore, fluid level sensors may be installed on the annulus to track the fluid level.

Radioactive tracer surveys are an alternative method to test the internal mechanical integrity, but are generally not preferred due to long test duration and potential concerns over injecting radioactive material in the wellbore. Tracer surveys can be used to pinpoint the location of a leak in the casing after damage to well integrity has been confirmed by another method. Tracer surveys are arguably the most sensitive existing well integrity test, provided that an accurate base log is made prior to the measurements. This method's sensitivity can also be disadvantageous, as it may result in false anomalies if the tool is not calibrated accurately. Tracer surveys have been successfully in detecting both internal and external leaks in West Pearl Queen and In Salah CO_2 (Ringrose, et al., 2009) sequestration pilot sites.

Temperature logs detect temperature anomalies behind the casing due to a leak on well completion, thus can give information on both internal and external mechanical integrity. Depending on the initial temperature differences, temperature logs can detect leaks as small as several litres per hour. The main disadvantage of temperature logs is their ineffectiveness in gas filled wells. Because of this, temperature logs will not be effective in testing internal mechanical integrity (tubing leaks) in most CO_2 injection wells. However, this does not affect the methods applicability to test external mechanical integrity. Another drawback of this method is that the well needs to be shut-in and thermally stabilized in order to have a successful measurement. Because of this, temperature logs may be considered a secondary external MIT option in an injection well.

Oxygen activation logs and noise logs can detect fluid movement behind the casing through different methods. Both methods do not require a liquid filled well, and can be performed during injection unlike temperature logs. Noise logs can give information from large distances, but require presence of irregular channels to create audible turbulences. At shallow depths, noise logs may be significantly influenced by noise from the surface, and may not give reliable results. In a virtually noiseless environment, noise logs can be the most sensitive external test. If the tools are compatible, a combined noise log and temperature log can be carried out to maximize the efficiency of the MIT.

Oxygen activation logs are very sensitive and may be difficult to interpret due to abundance of false positives. Repetitive measurements to confirm findings are often required. In addition, these logs have poor vertical resolution, and small range compared to other external MITs. The amount of information that can be gathered from confining layers is limited. In a CO_2 injection well, this would mean that the method may fail to detect small-sized fluid movements behind the casing.

There are two methods to test the integrity of abandonment plugs: pressure test or weight test. Pressure testing is the industry preferred method, and in essence is the same as the annular pressure test applied in the presence of a downhole plug. The weight test on the other hand, is carried out by applying the weight of a tubular string on the plug to test its structural stability. As the pressure test relies on testing the sealing capability of the plug against fluid movement, it will give a better indication of the seal integrity. Furthermore, the weight test requires the rental (and possible repairs) of a tubular string and a drilling/workover rig to run the string, which would introduce significant additional costs.
Prior to abandonment, a permeability test can be performed to determine the connection between two intervals behind the casing. In order to quantify the test results, and determine the effective permeability behind the casing accurate numerical modelling and information on downhole conditions are required. Although it appears to be an ideal integrity test, the results gathered from the test will give information specific to a small interval. Moreover, the test in its proposed form is in practice extremely difficult to implement to investigations targeting the cement sheath above the injection zone. Considering the fact that the test requires a leak path in the casing / liner to be formed, it is advised to perform the test only in the injection zone and the caprock. Vertical integrity tests can provide valuable information when carried out in a poorly cemented interval that has been confirmed by logs.

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