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# DESIGN AND MECHANICAL INTEGRITY OF $CO_2$ INJECTION WELLS

# KONSTRUKCIJA I MEHANIČKA CJELOVITOST BUŠOTINA ZA UTISKIVANJE $CO_2$

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**Key words:** carbon capture and storage (CCS), injection well, $CO_2$ injection, leakage, mechanical integrity

**Ključne riječi:** hvatanje i geološko uskladištenje ugljika (CS), utisna bušotina, utiskivanje $CO_2$, propuštanje, mehanička cjelovitost

**Abstract**

Geologic Sequestration (GS) is part of a process known as "carbon capture and storage (CCS)" and represents the process of injecting $CO_2$, into deep subsurface rock formations for long-term storage. For injecting of $CO_2$ existing wells are used as well as new drilled wells. A well represents the most likely route for leakage of $CO_2$ from geologic carbon sequestration. Maintaining mechanical integrity helps prevent the well and wellbore from becoming conduits for $CO_2$ migration out of the injection zone. The typical components of a $CO_2$ injection well are casing, tubing, cement, and packer. These components are relevant for maintaining mechanical integrity and ensuring $CO_2$ does not migrate upwards from the injection zone into underground source of drinking water (USDW); therefore helping to ensure zonal isolation of the injected carbon dioxide. In order to have the safe underground storage of $CO_2$ well integrity considerations should be present during all phases of well life including design phase, drilling, completion, injection, workover (service) and abandonment.

The paper describes well design, well integrity and mechanical integrity tests (MITs) as a means of measuring the adequacy of the construction of the injection well and as a way to detect problems within the well system.

**Sažetak**

Geološko skladištenje (GS) kao dio procesa "kaptiranje i skladištenje ugljičnog dioksida (CS)" predstavlja proces utiskivanja $CO_2$ u duboko zaliježuće stijene radi trajnog skladištenja. U tu svrhu koriste se postojeće bušotine, ali se izrađuju i nove bušotine. Bušotina predstavlja najvjerojatniji put za migraciju $CO_2$ iz stijena u kojima je on uskladišten. Održavanjem mehaničkog integriteta bušotine onemogućava se da bušotina i njen prstenasti prostor postanu putovi migracije $CO_2$ iz utisne zone prema površini. Osnovne komponente bušotine za utiskivanje $CO_2$ su: kolona zaštitnih cijevi, tubing, cementni kamen i paker. Ove komponente su bitne za održavanje mehaničkog integriteta i sprječavanje vertikalne migracije $CO_2$ iz utisne zone u stijene koje sadrže pitku vodu (USDW) jer pomažu da se izolira zona (naslage stijena) u koju je ugljični dioksid utisnut. Radi postizanja sigurnog uskladištenja $CO_2$ u podzemlju, integritet bušotine treba sagledati tijekom svih faza u radnom vijeku bušotine od planiranja, preko bušenja, opremanja, utiskivanja, održavanja (remonta) sve do trajnog napuštanja bušotine.

U radu se opisuju konstrukcija utisne bušotine, cjelovitost bušotine te navode testovi mehaničkog integriteta (MITs) kojima se određuje da li je primijenjena odgovarajuća konstrukcija utisne bušotine i otkrivaju problemi unutar kanala bušotine.

## Introduction

The interest in carbon capture and storage is relatively new, but the underground injection and effective storage of large quantities of $CO_2$ is not a new technology for oil and gas industry. In the last 10 years, most of the technologies developed through the last 44 years of $CO_2$ EOR (enhanced oil recovery) experience have been successfully applied in GS (geologic sequestration) for CCS (carbon capture and storage) in saline aquifers (Sweatman et al., 2009).

To date, the technology as a whole has only been deployed so far at a few pilot sites around the world such as the Sleipner field in Norway, Weyburn field in Canada, In Salah field in Algeria (Gallo et al., 2002, Jimenez and Chalaturnyk, 2002). The majority of locations that are being considered for carbon dioxide ($CO_2$) injection and sequestration are typically found in the areas that have a history of oil, natural gas, and/or coalbed methane production (Ennis-King and Paterson, 2002; Gallo et al., 2002;

Bellarby, 2009). Due to well logging and exploration activities in these regions, there is also a greater knowledge base for saline formations that lie either above or below oil and gas reservoirs.

For the EOR operations, thousands of injection wells have been successfully constructed and operated by numerous oil and gas companies in many different oil fields in the world. Unlike Croatia, in the United States injection wells are classified into five class, authorized under the Safe Drinking Water Act (SDWA), and regulated under the Underground Injection Control (UIC) Program. $CO_2$ is being injected in the U.S. under two well classifications: Class II and Class V experimental technology wells. In December 2010 the US EPA finalized regulations for a new class of injection well – Class VI well for geologic storage of $CO_2$ and established a path for commercial geologic carbon sequestration (US EPA, 2010 and 2011).

In Croatia, there are favourable natural conditions for geological storage of carbon dioxide – in the deep structural depressions of the southern Pannonian basin, and in the Adriatic off-shore as well (Saftić et al. , 2008). The most prospective objects in the near future are depleted hydrocarbon fields. In Ivanić oil field in the Sava depression, the pilot $CO_2$ injection has already been done as a part of an EOR project not for purpose of geologic storage.

The carbon dioxide injection is different than injection of other fluids because carbon dioxide is less dense than most subsurface fluids. It is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water. The well needs to maintain its integrity for the life of the project since the goal of GS is the long term storage of carbon dioxide. An improperly constructed well can lead to loss of well integrity that could lead to carbon dioxide or formation fluid leakage from the wellbore and into USDWs (Gasda et al., 2004 and 2005).

## $CO_2$ injection well design

The technologies for drilling and completing $CO_2$ injection wells are well developed. American Petroleum Institute published a number of Specification and Recommended Practices for Casing and Tubing, and Well Cements such as: *API Specification 5CT* – Specification for Casing and Tubing, *API RP 5C1* – Recommended Practices for Care and Use of Casing and Tubing, *API RP 10B-2* – Recommended Practice for Testing Well Cements, *API Specification 10A* – Specification on Cements and Materials for Well Cementing, *API RP 10D-2* – Recommended Practice for Centralizer Placement and Stop Collar Testing, and *API Specification 11D1* – Packers and Bridge Plugs.

Most aspects of drilling and completing such wells are similar or identical to that of drilling and completing a conventional gas (or other) injection well or a gas storage well, with the exception that much of the downhole equipment (e.g. casing and tubing, safety valves, cements, blowout preventers) must be upgraded for high pressure and corrosion resistance. The well is completed at the surface by installing a wellhead and "Christmas Tree" that sits on top of the wellhead and is an assembly of valves, pressure gauges and chokes. Devices are connected to the "Christmas Tree" that allow the monitoring of pressure, temperature, and injection rates (Figure 1). The combined wellhead has casing annulus valves to access all annular spaces to measure the pressure between the casing strings and between the casing and production tubular. Above the Christmas tree a $CO_2$ injection valve is mounted and an access valve for running wirelines from the top.

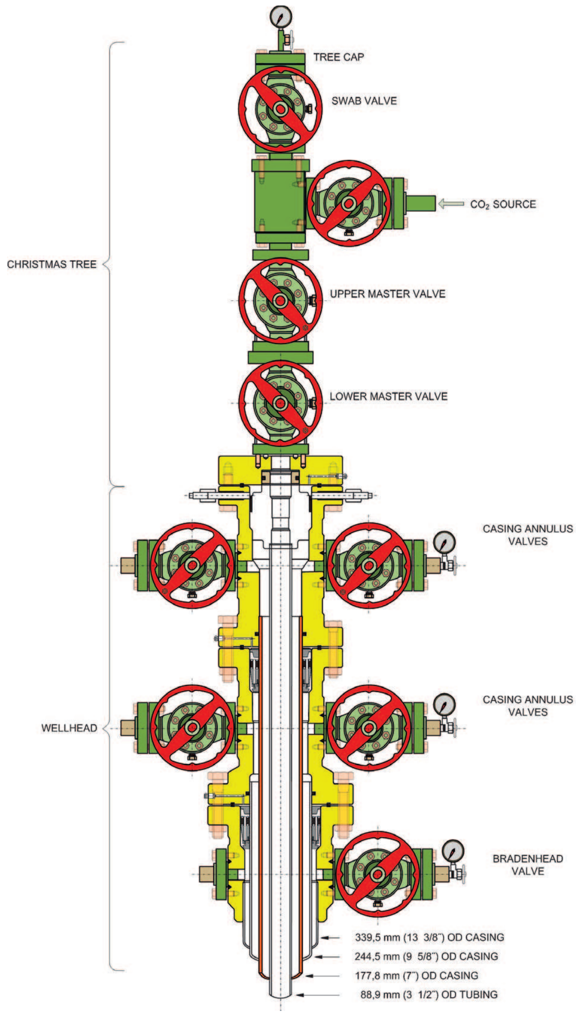


**Figure 1** Typical $CO_2$ Injection Wellhead
***Slika 1.*** *Tipična površinska oprema bušotine za utiskivanje* $CO_2$

The typical components of an injection well that are relevant to maintaining mechanical integrity and to ensuring that fluids do not migrate from the injection zone into USDWs are the casing, tubing, cement, and packer

(Figure 2). The well components should be designed to withstand the maximum anticipated stress in each direction – axial direction (tensile, compressive) or radial (collapse, burst), and include a safety factor. The loading in each of the stress directions should be compared to the strength of the material in that direction. The loadings correspond to the burst, collapse, and tensile strengths of the material.

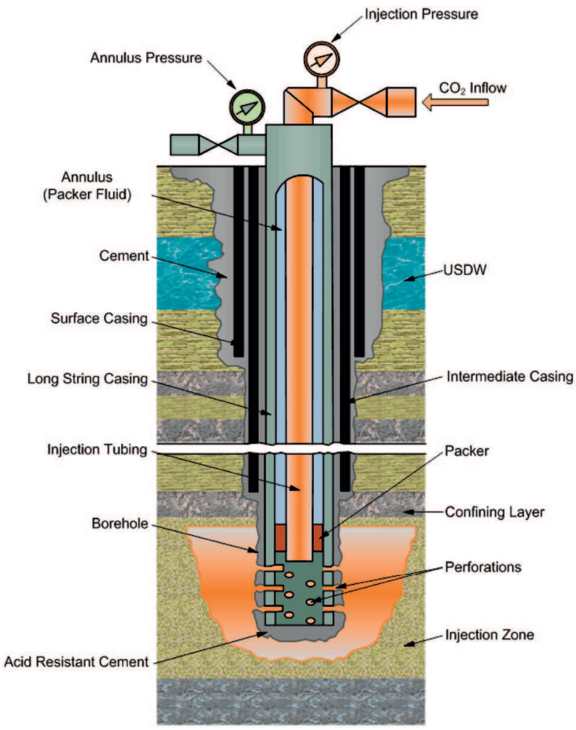


**Figure 2** Schematic of a $CO_2$ Injection Well (Gaurina-Međimurec, 2011)
***Slika 2.*** *Shematski prikaz bušotine za utiskivanje $CO_2$ (Gaurina-Međimurec, 2011)*

## *Casing*

An injection well typically consists of one or more casings. Leaks in the casing can allow fluid to escape into unintended zones or allow fluid movement between zones. The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered at the site-specific down-hole environment. Carbon dioxide in combination with water forms carbonic acid, which is corrosive to many materials. Native fluids can also contain corrosive elements such as brines and hydrogen sulfide. In $CO_2$ injection wells, the spaces between the long string casing and the intermediate casing, and between the intermediate casing and the surface casing as well as between the casings and the geologic formation are required to be filled with cement, along all casings.

## *Tubing*

The tubing runs inside the long string casing from the ground surface down to the injection zone. The injected fluid moves down the tubing, out through the perforations in the long string casing, and into the injection zone. The tubing ends at a point just below the packer. The space between the long string casing and tubing must be filled with a non-corrosive packer fluid. The tubing forms another barrier between the injected fluid and the long string casing. It must be designed to withstand the stresses and fluids with which it will come into contact. The tubing and long string casing act together to form two levels of protection between the carbon dioxide stream and the geologic formations above the injection zone. A safety valve/profile nipple can be used to isolate the wellbore from the formation to allow the tubing string to be replaced. Injection will be conducted through the perforated casing. In the base case there is no stimulation method used, but hydro fracturing may be an option. Using acids to improve injectivity is not recommended because of the possible damage to the cement sheath and casing.

## *Cement*

Cement is important for providing structural support of the casing, preventing contact of the casing with corrosive formation fluids, and preventing vertical movement of carbon dioxide. Some of the most current researches indicate that a good cement job is one of the key factors in effective zonal isolation. The proper placement of the cement is critical, as errors can be difficult to fix later on. Failing to cement the entire length of casing, failure of the cement to bond with the casing or formation, not centralizing the casing during cementing, cracking, and alteration of the cement can all allow migration of fluids along the wellbore. If carbon dioxide escapes the injection zone through the wellbore because of a failed cement job, the injection process must be interrupted to perform costly remedial cementing treatments. In a worst case scenario, failure of the cement sheath can result in the total loss of a well. During the injection phase, cement will only encounter $CO_2$. However after the injection phase and all the free $CO_2$ around the wellbore is dissolved in the brine, the wellbore will be attacked by carbonic acid ($H_2CO_3$). The carbonic acid will only attack the reservoir portion of the production casing, therefore special consideration of $CO_2$ cement needs only to be considered for the reservoir, primary seal and a safety zone above the reservoir. Regular cement should be sufficient over the $CO_2$-resistant cement. However since two different cement slurries will be used, $CO_2$-resistant cement that is compatible with regular Portland cement has to be used to prevent flash setting. The cement must be able to maintain a low permeability over lengthy exposure to reservoir conditions in a $CO_2$ injection and storage scenario. Long-term carbon sequestration conditions include contact of set cement with supercritical $CO_2$ (>31 ˚C at 73 bars) and brine solutions at increased pressure and temperature and decreased pH (Kutchko et al., 2007).

### *Packer*

A packer is a sealing device which keeps fluid from migrating from the injection zone into the annulus between the long string casing and tubing. The tubing is set on a retrievable packer above the injection zone to ease the changing of the tubing if pitting is identified during regular inspections. A packer must also be made of materials that are compatible with fluids which it will come into contact.

### *Design requirements*

All new $CO_2$ injection wells have to be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well has to be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors has to be considered: (1) depth to the injection zone; (2) injection pressure, external pressure, internal pressure, axial loading, etc.; (3) hole size; (4) size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material); (5) corrosiveness of injected fluids and formation fluids; (6) lithology of injection and confining zones; and (7) type and grade of cement. The following information concerning the injection zone has to be determined or calculated for new wells: (1) fluid pressure; (2) fracture pressure; and (3) physical and chemical characteristics of the formation fluids. Appropriate logs and other tests have to be conducted during the drilling and construction of new wells. Mandatory technical requirements for $CO_2$ injection well are presented in Table 1.

**Table 1** Mandatory Technical Requirements for $CO_2$ Injection Well (NETL, 2009)
***Tablica 1.*** *Obvezni tehnički zahtjevi za bušotine za utiskivanje $CO_2$ (NETL, 2009)*

| **Technical Requirements for $CO_2$ Injection Well (Class VI)** | |
|---|---|
| **Siting** | Extensive site characterization needed, including well logs, maps, cross-sections, USDW locations, determine injection zone porosity, identify any faults, and assess seismic history of the area. |
| **Fluid Movement** | No fluid movement to a USDW. |
| **Area of Review (AoR)** | Determined by computational model and reevaluated during project duration. |
| **Construction** | Two layers of corrosion-resistant casing required and set through lowermost USDW. Cement compatible with subsurface geology. |
| **Operation** | Injection pressures may not initiate or propagate fractures into the confining zone or cause fluid movement into USDWs. Quarterly reporting on injection, injected fluids and monitoring of USDWs within the AoR. Must report changes to facility, progress on compliance schedule, lose of mechanical integrity, or noncompliance with permit conditions. Permit valid for 10 years. |
| **Mechanical Integrity Test (MIT)** | Continuous internal integrity monitoring and annual external integrity testing. |
| **Monitoring** | Analyze injectant. Continuous temperature and pressure monitoring in the target formation. Plume tracking required. |
| **Closure** | 50 day notice and flush well. Must be plugged to prevent injectant from contaminating USDWs. |
| **Proof of Containment and Post-Closure Care** | Post-closure site care for 50 years or until proof of non endangerment to USDWs demonstrated. (No-migration petition demonstration; fluids remain in injection zone for 10 000 years). |
| **Financial Responsibility** | Periodically update the cost estimate for well plugging, post injection site care and site closure, and remediation to account for any amendments to the area of review and corrective action plan. EPA is also proposing that the owner or operator submit an adjusted cost estimate to the Director if the original demonstration is no longer adequate to cover the cost of the injection well plugging, post-injection site care, and site closure. |

**Degradation of wellbore cement due to $CO_2$ injection**

Portland cement systems are used conventionally for zonal isolation in oil or gas production wells. The properties of Portland cement are determined by the mineralogical composition of the clinker. When Portland cement is mixed with water, its compounds form hydration products. The main products formed by the cement hydration process are calcium silicate hydrate gel – CSH and calcium hydroxide - $Ca(OH)_2$. CSH is a semi-amorphous gel-like material that compromises approximately 70 wt % of the hydrated cement and is the primary binding material. Portland cement is thermodynamically unstable in $CO_2$-rich environments and can degrade rapidly upon exposure to $CO_2$ in the presence of water. As $CO_2$-laden water diffuses into the cement matrix, the dissociated acid ($H_2CO_3$) reacts with the free calcium hydroxide and the calcium-silicate-hydrate gel. The reaction products are soluble and migrate out of the cement matrix. Eventually, the compressive strength of the set cement decreases and the permeability and porosity increase, leading to loss of zonal isolation (Gaurina-Međimurec, 2010). There are mainly three different chemical reactions involved in cement-$CO_2$ interaction shown in table 2 (Onan,1984; Bellarby, 2009; Santra et al., 2009).

$CO_2$ diffuses into the capillary pores of the cement which contain, to some extent, water and dissolves in it to form carbonic acid (Eq. 1). Forming of carbonic acid causes lowering in pH value, depending on temperature, partial pressure of $CO_2$, and other ions present in water, such as salt, etc. Carbonic acid reacts with calcium hydroxide (also named as hydrated lime or portlandite) in the cement causing carbonation of $Ca(OH)_2$ (Eq. 2a) and/or decomposition of calcium silicate hydrate gel, the main binding component in hydrated cement, into calcium carbonate and an amorphous silica (Eq. 2b). The carbonation reactions will cause densification, leading to increased hardness and reduced permeability thereby decreasing $CO_2$ diffusion and up to 6% volume expansion, which can lead to development of micro to macro cracks in extreme cases. This carbonation reaction dissolves and weakens the cement making it liable to ultimately leak. The rate at which cement degradation occurs depends primarily on temperature, but also on cement type, cement composition, water/cement ratio, moisture content, $CO_2$ partial pressure, and porosity/permeability (Kutchko et al., 2007, Santra et al., 2009). Carbonation is extremely fast in the early days but later slows down drastically because of the time dependant reduced porosity/permeability caused by the initial carbonation itself (Santra et al., 2009). Dissolution of $CaCO_3$ is a long-term phenomenon and happens only when the set cement is surrounded by liquid water containing dissolved $CO_2$ (Eq. 3). Effects of this reaction are increased porosity/permeability and loss of overall mechanical integrity, leading to inefficient or even potential loss of zonal isolation in extreme cases. Several approaches have been adopted to help reduce detrimental effects of carbonation (Santra et al., 2009): (a) reduce the amount of Portland cement by incorporating filler, (b) reduce porosity/permeability, (c) add reactive supplementary materials to reduce the $Ca(OH)_2$, as well as changing the CSH composition to a more $CO_2$-resistant one.

**Mechanical integrity**

Mechanical integrity is a key concept related to the performance of an injection well, and the prevention of injected fluid movement into or between USDWs or other zones. Mechanical integrity of the well is achieved by ensuring that each of the components of the well are constructed with appropriate materials and are functioning together as intended. Typical corrosion resistant materials include 316 stainless steel, fiberglass, or lined carbon steel for casing and tubing. Casing and tubing can be lined with glass reinforced epoxy, plastic, or cement. If lined casing or tubing is used, care is recommended during installation to avoid damaging the lining (Meyer, 2007). Other metal parts such as packers and valves can be nickel plated or made of other high nickel alloys (Table 3).

**Table 2** The Main Chemical Reactions Involved in Cement-$CO_2$ Interaction
***Tablica 2.*** *Glavne kemijske reakcije u procesu djelovanja $CO_2$ na cementni kamen*

| The main chemical reactions | |
|---|---|
| 1. Formation of carbonic acid | $CO_2 + H_2O \rightarrow H_2CO_3$ (Eq. 1) |
| 2. Carbonation of Calcium Hydroxide and/or cement hydrates | $Ca(OH)_2 + H_2CO_3 \rightarrow CaCO_3 + 2H_2O$ (Eq. 2a)<br>C-S-H and/or crystalline phases + $H_2CO_3 \rightarrow CaCO_3 + SiO_2$ (gel) + $H_2O$ (Eq. 2b) |
| 3. Dissolution of $CaCO_3$ | $CaCO_3 + H_2CO_3 \rightarrow Ca(HCO_3)_2$ (Eq. 3) |

**Table 3** Materials of construction for $CO_2$ injection wells (Meyer, 2007)
***Tablica 3.*** *Konstrukcijski materijali opreme bušotina za utiskivanje $CO_2$ (Meyer, 2007)*

| Component | Materials of construction |
|---|---|
| Upstream Metering & Piping Runs | 316 SS, Fiberglass |
| Christmas Tree (Trim) | 316 SS, Nickel, Monel |
| Valve Packing and Seals | Teflon, Nylon |
| Wellhead (Trim) | 316 SS, Nickel, Monel |
| Tubing Hanger | 316 SS, Incoloy |
| Tubing | GRE lined carbon steel,<br>IPC carbon steel, CRA |
| Tubing Joint Seals | Seal ring (GRE)<br>Coated theards and collars (IPC) |
| ON/OFF Tool, Profile Nipple | Nickel plated wetted parts, 316 SS |
| Packers | Internally coated hardened rubber of 80-90<br>durometer strenght (Buna-N),<br>Nickel plated wetted parts |

Several potential leakage pathways can occur along active injection well (Figure 3a) and/or abandoned well (Figure 3b). These include leakage: through deterioration (corrosion) of the tubing (1), around packer (2), through deterioration (corrosion) of the casing (3), between the outside of the casing and the cement (4), through deterioration of the cement in the annulus (cement fractures) (5), leakage in the annular region between the cement and the formation (6), through the cement plug (7), and between the cement and the inside of the casing (8).

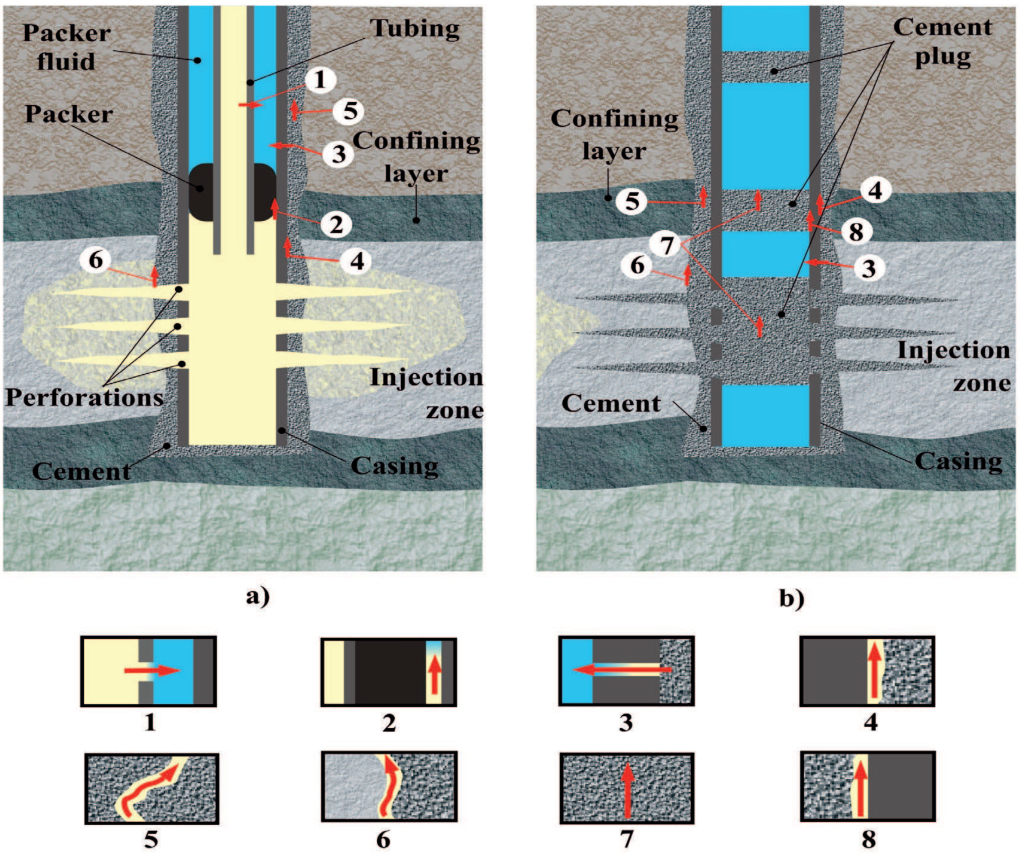


**Figure 3** Possible Leakage Pathwys in an Active $CO_2$ Well (a) and Abandoned Well (b)
***Slika 3.*** *Mogući putevi migracije fluida u aktivnoj (a) i napuštenoj (b) bušotini*

Maintaining mechanical integrity helps prevent the well and wellbore from becoming conduits for fluid migration out of the injection zone. There are two aspects of mechanical integrity: internal and external**.**

### *Internal mechanical integrity*

Internal mechanical integrity is defined as the absence of significant leaks in the casing, tubing, or packer. These well components act as the main barriers preventing contact between the injected carbon dioxide stream and the surrounding geologic formations through which the well has been drilled and constructed. Ensuring that these components are constructed properly with appropriate materials and that they remain undamaged when subject to stresses or corrosive (and other) operational conditions may prevent carbon dioxide from moving out of the well bore during injection (NETL, 2009). The pressure applied during an internal mechanical integrity test should be limited to prevent casing ballooning that could create cement defects.

The absence of significant leaks in the casing, tubing, or packer is demonstrated through the use of (1) the standard annulus pressure test (SAPT), (2) the standard annulus monitoring test (SAMT), and (3) the radioactive tracer survey (RTS).

### *External mechanical integrity*

External mechanical integrity is defined as the absence of significant leakage outside of the casing. Maintaining external mechanical integrity helps to ensure that the injected carbon dioxide, which tends to be more buoyant than native formation fluids, does not migrate upwards from the injection zone after it has been injected; therefore helping to ensure zonal isolation of the injected carbon dioxide. The main construction component ensuring external mechanical integrity is the set cement. Properly emplaced cement should both prevent fluid movement by sealing the space between the casing and the formation, and protect the well casing from stress and corrosion.

The absence of significant fluid movement into an USDW through vertical channels adjacent to the injection well bore is demonstrated through the use of (1) the results of a temperature log, (2) noise log, (3) oxygen activation log (OAL), (4) the results of a radioactive tracer survey (RTS) (when the injection zone is separated from the lowermost USDW by a single confining layer), or (5) cementing records (Ultrasonic well logging; Cement bond log – CBL) demonstrating the presence of adequate cement to prevent fluid migration into USDWs.

## Conclusion

In order to have the safe underground storage of carbon, the injection wells as well as any well penetrating through the cap rock have to maintain sufficient integrity over a long time period. Well integrity considerations should be present during all phases of well life including design phase, drilling, completion, injection, workover (service) and abandonment. Both existing and new wells must be fully evaluated and tested for integrity because there are many different possible leakage pathways. It is necessary to examine the condition of the casing and the cement and identify any annuli or defects that exist within the well. There is no one tool or method capable of looking at all of these features at the same time, so a suite of measurements must be run to analyze the integrity of a well. These measurements can be acquired using wireline tools such as caliper and ultrasonic tools to measure the integrity of the casing, sonic and ultrasonic tools to measure the integrity of the well cement, and tools to sample the casing, cement, formation, and formation fluid. The choice of well equipment and materials must be carefully considered to achieve the desired integrity. $CO_2$ corrosion may be limited by: the selection of high alloy chromium steels, resistant to corrosion, and by inhibitor injection, if using carbon steel casing. In addition use of acid resistant cement is highly recommended.

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