Review of failures for wells used for CO\textsubscript{2} and acid gas injection in Alberta, Canada

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Abstract

Wells have been identified as posing a greater risk for leakage from CO\textsubscript{2} storage sites than geological features such as faults and fractures, particularly in mature sedimentary basins with high well density such as those onshore in North America. A commonly-held belief is that CO\textsubscript{2} injection wells will pose a lesser risk than wells drilled for other purposes because greater care would be taken in regard to their completion and operation. The existence of CO\textsubscript{2} and acid gas injection operations in Alberta, Canada, provided the opportunity to test this hypothesis. Currently in Alberta there are 31 wells used for CO\textsubscript{2} injection and 48 wells used for the disposal of produced acid gas (a mixture of CO\textsubscript{2} and H\textsubscript{2}S that is separated from sour gas to meet pipeline and market specifications). Only 22 wells were drilled specifically with the purpose of injecting CO\textsubscript{2} or acid gas; all others are previous wells that have been subsequently converted to injection wells. Well failures include: surface casing vent flow, casing failure, tubing failure, packer failure, and zonal isolation failure. The incidence of well failure is greater in the case of converted wells than in the case of wells drilled and completed for injection purposes. Most failures are not caused by injection; they are due to general causes encountered in the general well population. Failures due to injection are mostly tubing and packer failures, which are monitored by regulation and are easily detected and repaired. The incidence of well failure is greater for wells drilled prior to the advent of regulations in 1994 regarding drilling and completion of injection wells. While the incidence of failure in the CO\textsubscript{2} and acid gas injection wells in Alberta is comparable to that in the general well population, the analysis indicates that injection wells drilled for purpose and under a proper regulatory regime have a lesser incidence of failure than the general well population. A proper regulatory framework for CO\textsubscript{2} injection wells is essential for reducing and preventing well failures.

Keywords: CO\textsubscript{2} injection wells; acid gas injection; well failure; well leakage; Alberta

1. Introduction

A viable CO\textsubscript{2} storage site must meet capacity, injectivity and confinement requirements. The last requirement is particularly important from safety, risk and remediation points of view. Although faults and fractures have been...
generally identified as potential CO₂ leakage pathways, it is believed that these pose a smaller risk if storage sites are properly selected and operated, particularly in regard to maximum injection pressures. On the other hand, wells have been identified as posing a greater risk for leakage, particularly in densely-drilled onshore sedimentary basins like those in North America. From a leakage-potential point of view, wells fall into three categories:

1) existing (old) wells drilled for exploration, production and other purposes;
2) CO₂ injection wells built for purpose; and
3) future wells that will be drilled for other purposes through a CO₂ storage unit.

A commonly-held belief is that CO₂ injection wells will pose a lesser risk than existing wells drilled for other purposes because greater care would be taken in regard to their completion and operation.

The records of the regulatory agency in Alberta, Canada, contain information about more than 350,000 wells, and these have been previously analyzed to identify factors that affect the potential for leakage along wells [1] and the potential for leakage in the shallow and deep parts of a well [2, 3]. Regulatory requirements regarding well drilling, completion and abandonment were shown to be one of the important factors affecting and indicating the potential of a well to leak [1, 2]. The existence of CO₂ enhanced oil recovery (EOR) and acid gas disposal operations in Alberta, with 31 and 48 injection wells, respectively, provided the opportunity to analyze the incidence of well failure and the potential for well leakage in these wells compared with the general well population. Information from well tour reports, from electronic data bases containing data reported by operators, and cement evaluation and casing inspection logs were used in the analysis. The majority of these CO₂ and acid gas injection wells are actually older wells, built for a different purpose then subsequently converted to injection. Figure 1 shows the geographic distribution of CO₂ and acid gas injection wells in Alberta, as well as their distribution by lithology of the injection unit and by type (built on purpose or converted).

Figure 1: Characteristics of acid gas and CO₂ injection wells in Alberta as of 2008 by category: a) location, b) lithology of the injection unit, and c) if built for injection or converted.
Figure 2 above shows the type of materials (cement and casing) used in the construction of these 79 injection wells. It can be seen that in most cases regular materials have been used, like class G neat cement and J55 or K55 grade casing. This is the case of the wells originally built for a different purpose and subsequently converted into CO₂ or acid gas injection wells; only in about a quarter of wells were special materials like sulphur-resistant casing (L80 or N80) used, which corresponds to the wells built for the purpose of injection (Figure 1c).

Prior to 1994, approval for injection and disposal wells in Alberta was granted on a case-by-case basis. In 1994 the provincial regulatory agency issued Directive 51 for injection and disposal wells, including well classification, completion, testing and reporting requirements [4]. Hydraulic isolation of the host zone and cementing across useable groundwater is a requirement for Class III injection wells, which are wells for the injection of CO₂, inert, acid and sour gases. Applications for CO₂ injection for EOR purposes or for acid gas disposal are handled separately [5], but the requirements for well drilling, completion and operation are the same in both cases. After an application is approved and permit to inject is granted, the operator must meet wellhead pressure limitations and must perform annually a packer isolation test. In addition, the operator must report any well failures upon detection. These failures are typically detected during required annual testing or well workovers.

2. Analysis

The analysis was carried out by category (CO₂ injection or acid gas disposal), by initial purpose (for CO₂ or acid gas injection, or for other purpose and then converted), by timing of drilling and completion in relation to 1994 when regulatory requirements regarding ERCB Class III injection wells were introduced, and by type of well failure. Failures were separated into various areas or equipment of the wellbore, allowing thus to determine if they were a direct result of CO₂ or acid gas injection, or the result of general factors that affect the general well population in Alberta [1-3]. Well failures include: 1) tubing and/or casing failure (e.g., thread failure, mechanical damage, internal or external corrosion, and excessive pressure); 2) packer failure (packer body, external packer sealing elements or seal bore elements); 3) zonal isolation (quality of cement and cement bonds); and 4) surface casing vent flow (SCVF, known elsewhere as sustained casing pressure, or SCP) or gas migration (GM), which are gas flow inside and outside surface casing, respectively. Well failures can be of general nature and may occur in any wellbore regardless of its use (e.g., SCVF or casing failure due to external corrosion), or specific to injection, usually due to pressure, temperature and gas composition. All failures were considered in the analysis, although, once detected, they were repaired as required by regulation except for SCVF and GM, which must be repaired prior to well abandonment unless the gas flow is serious, in which case the failure must be repaired upon detection [6].
the source of SCVF and GM is a shallower horizon than the injection unit [2, 3], these well failures were considered in the analysis because they provide a leakage pathway once zonal isolation and/or casing fail.

The vast majority of failures caused by injection are tubing and packer failures (Figure 3a), whereas general well failures are predominantly casing failure or SCVF generally caused by low cement top which leaves potential gas-bearing zones open to surface and leads to external casing corrosion in uncemented intervals [2]. There is only one occurrence of both casing failure and SCVF caused by CO$_2$ injection in the same well. A casing split occurred at 183.2 m depth, which resulted in temporary uncontrolled flow of CO$_2$ from the surface casing through the surface casing vent. It is unclear if this failure occurred prior to or during well workover, and it was quickly repaired by installing new casing. It is worth mentioning here that in the neighboring province of British Columbia there are ten acid gas disposal operations, and the records of the provincial regulatory agency show that both tubing and casing failures occurred in several places in one injection well because of ice formation in the annular fluid. Continuous injection over two years of very cold (-10 to -20 °C) acid gas led to a substantial cooling of the upper section of the well and possibly of some of the adjacent rock mass. The water/mud in the 178×273 mm annulus froze at some point, and the ice that formed generated sufficient force to damage the 178 mm casing and collapse the 114 mm tubing. Subsequent analysis of the recovered 114 mm and 178 mm pipes did not find any evidence of corrosion or H$_2$S brittleness that may have contributed to well failure. The well was repaired and since then the injected acid gas is pre-heated to temperatures above freezing to avoid this situation from reoccurring.

Figure 3b shows that the incidence of general wellbore failures per well is greater in the case of converted wells than in the case of wells built for purpose, most likely because of better cementing of the top part of the well in the case of the latter than in the case of the former. On the other hand, the incidence of injection-specific wellbore failures is higher in the case of the wells built for purpose, and this may be related to the presence of H$_2$S in the injection stream since three quarters of the wells built for purpose are acid gas disposal wells. However, the built-for-purpose wells have a significantly lower incidence of failure than the converted wells (Figure 3b).

When all failure modes are considered, the acid gas disposal wells have a lower failure rate per well than the CO$_2$-injection wells (Figure 4a), most likely due to more stringent design criteria and maintenance schedules employed by the operators due to the toxic nature of the injected acid gas and the associated risk to the environment and public safety in the event of failure.

Figure 3: Comparison of failures in acid gas and CO$_2$ injection wells that are specific to injection and that are general in nature: a) number of failures by type of failure, b) failures per well by type of well (built on purpose or converted).
Figure 4b clearly shows that, for both acid gas and CO₂ injection wells, wells built for purpose have a much lower failure rate than converted wells, although this difference is due mainly to general wellbore failures, predominantly SCVF and GM, unrelated to injection (Figure 3). Injection-related failure rates are similar in wells built for purpose or converted, which is expected since tubing and packers are easily replaced at conversion with equipment that it is fit for purpose, while casing and cement are installed during original drilling operations and cannot be easily and economically replaced.

The first CO₂ injection in Alberta started in 1981 specifically for enhanced oil recovery (EOR), and currently there are seven sites where CO₂ is or has been used for CO₂-EOR, with the number of wells having been drilled almost evenly prior to and after 1994 when regulatory requirements for Class III injection wells were introduced (Figure 5a). In contrast, the first acid gas disposal operation started in 1991 after regulatory requirements significantly restricted H₂S flaring, and most wells were built after 1994 (Figure 5a). The failure rate per well clearly decreased for wells built or converted after 1994 (Figure 5b), showing the definite effect of improved regulatory requirements.

Figure 5: Comparison of failures in acid gas and CO₂ injection wells by well category in relation to changes in regulatory requirements regarding well completion and isolation: a) number of wells, b) failures per well.
Previously identified factors that increase a well leakage potential, and a scoring method developed for ranking the potential for well leakage [2, 3] were applied to the existing 79 acid gas and CO₂ injection wells in Alberta. Two broad well failure types can be predicted on the basis of the previous analysis: 1) potential for loss of zonal isolation, based on number of perforated intervals, fracture and/or acid stimulations, and cement type used across the perforated interval that may be at risk in contact with CO₂ and H₂S; and 2) potential for non-injection related failures, mostly casing failure, SCVF and/or GM, as a result of low cement top. Figure 6 above shows the results of applying this analysis to the 79 acid gas and CO₂ injection wells in Alberta. Only 37% of these wells are fully cemented to the surface. However, although the potential exists for loss of zonal isolation, which is the first engineered barrier against leakage, no such incident was ever reported. It should be noted here that, after the start of injection, confirmation of zonal isolation is not a requirement, therefore undetected loss of zonal isolation may exist.

Regulatory requirements for acid gas or CO₂ injection wells in Alberta [7] specify that groundwater, defined as water with salinity up to 4000 mg/l, must be protected by surface casing, run and cemented to below the base of protected groundwater, or the next string of casing must be cemented to surface to isolate all non-saline groundwater from hydrocarbon-producing zones and to protect groundwater from saline formation water. Examination of the tour reports for the 79 CO₂ and acid gas injection wells indicates that 21 acid gas disposal wells and 2 CO₂ injection wells have groundwater protected behind surface casing, while 22 acid gas and 12 CO₂ injection wells have groundwater protected by cementing the next sting of casing to surface. Only 5 acid gas disposal wells and 17 CO₂ injection wells have groundwater exposed. The wells built for purpose have full groundwater protection, while not all the converted wells, particularly the ones built prior to the introduction of regulatory requirements [7], meet cementing requirements. This shows again the need for and importance of proper regulatory requirements for CO₂ and acid gas injection wells.
3. Conclusions

The analysis of failures for current CO₂ and acid gas injection wells in Alberta indicates that:

- Wells built specifically for CO₂ or acid gas injection have significantly fewer general wellbore failures than wells drilled and completed for other purposes and subsequently converted to injection wells.
- Almost all of the injection-related failures are failures of tubing or packer and are readily identified and repaired.
- Regulations implemented for injection wells have little impact on general wellbore failures such as surface casing vent flow and gas migration, which occur in the shallower part of wells, but it seems to have reduced the failure rate for injection-related failures.
- General wellbore failure potential, although not negligible, is easily managed due to the required regulatory framework which requires stringent monitoring and repair.
- Acid gas disposal wells have a lower failure rate than CO₂ injection wells, which may be the result of more diligence on the part of the operators, and of more stringent regulatory requirements due to the toxic nature of the H₂S contained in the injected acid gas and its potential impact on the environment and public safety in case of leakage.
- The implementation of a proper regulatory framework for the drilling, cementing, completion and abandonment of CO₂ and acid gas injection wells is essential for reducing and preventing injection well failures, preventing gas leakage, protecting groundwater and energy resources, and protecting public safety.

Generally, the analysis shows that the safety of CO₂ and acid gas injection wells is enhanced if a regulatory regime is put in place to address directly and specifically this class of wells, and when injection wells are drilled, completed, operated and monitored for purpose. A key element in reducing the incidence of general well failures, both for injection and any other purpose well, is cementing to the surface, while reducing the rate of failures due to injection can be achieved by implementing a proper well monitoring and maintenance schedule. It is important to stress here that, although well failures as defined here occurred in both acid gas and CO₂ injection wells, no leak of acid gas ever occurred, and only in one case did CO₂ leak through the surface casing vent with no adverse effects, and the failure was quickly repaired. Failures due to injection (tubing or packer) do not result in an uncontrolled flow to surface and are generally quickly detected and repaired. At no time in the history of close to 30 years of CO₂ and acid gas injection in Alberta was public safety at risk as a result of these injection operations.

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References


² All ERCB documents are available on the ERCB web site at www.ercb.ca