# Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the $CO_2$ Capture Project

## Geologic Storage of Carbon Dioxide with Monitoring and Verification

*Volume 2*

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# Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the $CO_2$ Capture Project

## Geologic Storage of Carbon Dioxide with Monitoring and Verification

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# Chapter 12

# IN SITU CHARACTERISTICS OF ACID-GAS INJECTION OPERATIONS IN THE ALBERTA BASIN, WESTERN CANADA: DEMONSTRATION OF $CO_2$ GEOLOGICAL STORAGE

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## ABSTRACT

Acid-gas injection in the Alberta basin in western Canada occurs over a wide range of subsurface characteristics, acid gas compositions, and operating conditions. The subsurface characteristics of the injection sites are representative for compacted continental sedimentary basins, like those in the North American mid-continent. No safety or leakage incidents have been reported in the 15 years since the first acid-gas injection operation in the world started in Alberta, and this record indicates that acid-gas injection is a mature technology that can be applied elsewhere in the world. Furthermore, these acid-gas injection operations constitute a commercial-scale analogue for future large-scale $CO_2$ geological storage operations to reduce $CO_2$ emissions into the atmosphere from large $CO_2$ point sources. This review of the subsurface characteristics of the acid-gas injection operations in western Canada provides data and information that can be used in future studies for site selection.

## INTRODUCTION

Deep sour-gas reservoirs in the Alberta basin in western Canada contain hydrogen sulphide ($H_2S$) that has to be removed from the produced gas to meet pipeline and market specifications, generating in the process acid gas (a mixture of $H_2S$ and $CO_2$). Since 1989, regulatory agencies in western Canada require that gas plants with a sulphur throughput of more than 1 t/d recover the sulphur from the acid-gas stream rather than burn it in flare stacks or incinerators, as previously done if sulphur-recovery technology could not economically remove the sulphur. Because desulphurization is uneconomic in a weak market dominated by recovered sulphur, and the surface storage of the produced sulphur constitutes a liability, increasingly more operators in the Alberta basin are turning to acid-gas disposal through injection into deep geological formations. Compared to other options, acid-gas injection has less environmental consequences than sulphur recovery (where leaching of sulphur piles can lead to groundwater contamination) or flaring (which essentially substitutes $SO_2$ for $H_2S$ in the atmosphere, as well as releasing $CO_2$). In addition, although the purpose of acid-gas injection is to dispose of $H_2S$, significant quantities of $CO_2$ are being injected at the same time because of the cost involved in separating the two gases, thus reducing the release of $CO_2$ into the atmosphere.

Forty-eight injection sites have been approved since the start of the first acid-gas injection operation in 1989, of which 41 are currently active. One operation was not implemented, three were rescinded after a period of operation, either because injection volumes reached the approved limit, or because the gas plant producing the acid gas was decommissioned, and three sites have been suspended by the regulatory agency because of reservoir overpressuring. The annual injection rate in 2003 varied between 0.5 and 280 kt/yr, with an average of 25 kt/yr. By the end of 2003, approximately 2.5 Mt $CO_2$ and 2 Mt $H_2S$ have been injected into deep saline formations and depleted hydrocarbon reservoirs in western Canada.

These acid-gas injection operations constitute a commercial-scale analogue to geological storage of $CO_2$, with a 15-year track record of industrial implementation and regulatory stewardship. Because acid-gas injection occurs over a wide range of characteristics in the subsurface environment, acid gas compositions and operating conditions, these operations are truly representative of the geological media that most likely will be the target for large-scale $CO_2$ geological storage, particularly for continental sedimentary basins like the ones in North America situated between the Rocky and Appalachian mountains.

## REGULATORY REQUIREMENTS

In Alberta, the Oil and Gas Conservation Act requires that operators apply for and obtain approval to dispose of acid gas from the Alberta Energy and Utilities Board (EUB), a provincial regulatory agency. Similarly, in British Columbia (BC) operators have to apply to the BC Oil and Gas Commission for approval. The regulatory agencies review applications to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety. To adequately address these matters, the regulators require that the applicants submit information regarding surface facilities, injection well configurations, characteristics of the injection reservoir or saline formation, and operations. Approvals set limits for the maximum $H_2S$ mole fraction in the injected acid-gas stream, maximum wellhead injection pressure and rate, maximum volume, and the size of the Emergency Protection Zone (EPZ) in the case of an atmospheric release of $H_2S$. No application has been rejected to date; however, in some cases the operator had to provide additional information and/or had to make changes to satisfy requirements and requests from the regulatory agencies. After approval for acid-gas injection is granted, the operators have to submit to the regulatory agencies (bi)-annual progress reports. These progress reports usually contain information about the actual composition of the injected acid gas, and wellhead injection pressure, temperature, volume and rate.

The selection of an acid-gas injection site needs to address various considerations that relate to (1) proximity of the injection site to the sour oil and gas facility that is the source of acid gas; (2) confinement of the injected gas; (3) effect of acid gas on the rock matrix; (4) protection of energy, mineral and groundwater resources; (5) equity interests; and (6) wellbore integrity and public safety [1–3]. The specific location is based on a general assessment of the regional geology and hydrogeology, which is designed to evaluate the potential for leakage [3]. The injection wells are considered as Class III disposal wells, unless the acid gas is dissolved in produced water prior to injection, in which case the well is designated as either Class Ib or Class II, depending on the produced-water designation.[1] Completion and logging requirements are similar for Class II and III wells, and include: (1) identification of all geological zones using logs and/or cores; (2) isolation by cement of all potential hydrocarbon-bearing zones and shallow potable groundwater aquifers; (3) confirmation of hydraulic isolation and cement integrity by a full-length cement bond log; (4) injection through tubing, and filling of the annulus with a corrosion-inhibiting fluid; and (5) installation of safety devices both above the ground and in the well bore to ensure that failure of any component in the system does not result in environmental damage and risk to life.

The integrity of the acid-gas disposal zone is critical. To optimize disposal and minimize risk, advantage is taken of the properties of the acid gas [5,6], which is injected: (1) in a dense-fluid phase (liquid or supercritical), to increase storage capacity and decrease buoyancy; (2) at bottom-hole pressures greater than the formation or reservoir pressure; (3) at temperatures in the system generally greater than 35 °C to avoid hydrate forming, which could plug the pipeline and disposal well; and (4) with water content below the saturation limit, to avoid corrosion. Because of a water-solubility minimum in the 3–5 MPa pressure range that depends on the acid gas composition, dehydration is naturally supplied in most cases by the compression cycle [7,8]. Only in a few cases triethylene glycol, refrigeration, or a desiccant is used.

To avoid gas migration through the cap rock, the difference between the pressure at the top of the disposal formation and the pressure in the confining layer must be less than the cap rock threshold displacement pressure (the pressure needed for the acid gas to overcome the capillarity barrier and displace the water that saturates the cap rock pore space). The injection zone must be free of natural fractures, and the bottom hole injection pressure (BHIP), although higher than the formation or reservoir pressure, must be below 90% of the rock-fracturing threshold, to avoid inducing fractures. Lately, if acid gas is injected into a depleted oil

[1] Well classification in western Canada is different from EPA classification in the United States [4].

or gas reservoir, regulatory agencies set the maximum BHIP at the initial reservoir pressure or at 10% lower to ensure reservoir integrity.

A historical review of acid-gas injection operations, based on published literature to date, is provided in Ref. [9].

## OPERATING CHARACTERISTICS

Acid gas is injected in the Alberta basin in free phase (*dry acid gas*), dissolved in, or mixed with water. Two originally water disposal operations have been subsequently approved to co-inject acid gas dissolved at surface at very low concentrations in very large volumes of water, resulting in a weak acidic solution (*sour water*) that is injected deep into the ground through 17 and 49 wells, respectively. Because the water has a much larger capacity for dissolved acid gas than actually used, there are no safety issues relating to the possibility of a well blow out, and these operations are generally not subject to the same level of requirements as the other operations. A third sour water injection operation has also been implemented. At seven other sites, of which three have been rescinded, wet acid gas (i.e. acid gas with free water present) is injected. The free water is present in these cases as a result of mixing at surface. Dry acid gas is injected at all other sites (i.e. no free water is present). Figure 1a shows the location of the various acid gas sites in the Alberta basin and the type of injection.

The approved $H_2S$ mole fraction of the injected acid gas varies between 5 and 97%. The rest comprises mostly $CO_2$, with a few percent $C^+$ gases for the balance, except for the cases where the acid gas is dissolved in or contains free water. Table 1 shows the operating range of the licensed acid-gas operations and of the actually injected acid gases. Averages of the actual operating characteristics were calculated on the basis of the progress reports submitted by the operators to the regulatory agencies (Table 1 and Figure 2a). Based on the estimated total injection volume and capacity of the injection reservoir or saline formation, the acid-gas injection sites are planned to operate for periods of 10–25 years.

Usually four-stage electric or diesel compressors are used to bring the acid gas to the wellhead pressure needed for injection. Compressor power varies between 50 and 900 hp (horse power). Dehydration of the acid gas is achieved in most cases naturally through the compressing cycle. In a few cases refrigeration or dry desiccation is used. Pipelines from the gas plant to the injection well are on the order of several hundred meters, with the shortest at 130 m and the longest at 20 km. Pipeline diameter ranges from 48.3 to 168.3 mm, and pipeline wall thickness varies between 3.2 and 11.1 mm.

Injection takes place usually through a single well, although in several cases more than one well is used. The well consists of a central steel tubing string with an outer annulus bounded by a steel casing that is cemented to the subsurface formations. Well casing varies in diameter from 114 to 244 mm, and the diameter of the well tubing ranges from 60.3 to 178 mm. The wells are protected against corrosion with inhibited crude oil, inhibited fresh or produced water, or diesel in the annulus. The casing is isolated by installing a packer, which is pressure tested for integrity once a year, in the annulus between the casing and the tubing string just above the disposal formation. A down-hole safety valve or a check valve is incorporated in the tubing string so that, if equipment fails at surface, the well is automatically shut-in to prevent acid gas backflow. The wellhead of the injection well is similarly protected with valves. The surface facilities and injection well are monitored for leaks, but no in situ monitoring is performed.

## IN SITU CHARACTERISTICS

In their pure state, $CO_2$ and $H_2S$ have similar phase equilibria, with $CO_2$ condensing at lower temperatures than $H_2S$ [10]. The critical points are $T = 31.1\,°C$ and $P = 7380\,kPa$ for $CO_2$ and $T = 100.2\,°C$ and $P = 8963\,kPa$ for $H_2S$ (Figure 2b). The phase behavior of the acid-gas system is represented by a continuous series of two-phase envelopes separating the liquid and gas phases, located between the $CO_2$ and $H_2S$ bounding systems in the pressure–temperature space. The in situ temperature and pressure position of the injected acid gas is located in the $P$–$T$ space mostly between the supercritical points for $CO_2$ and $H_2S$ (Figure 2b). Phase calculations [11] indicate that the acid gas will be mostly in liquid phase as a result of gas

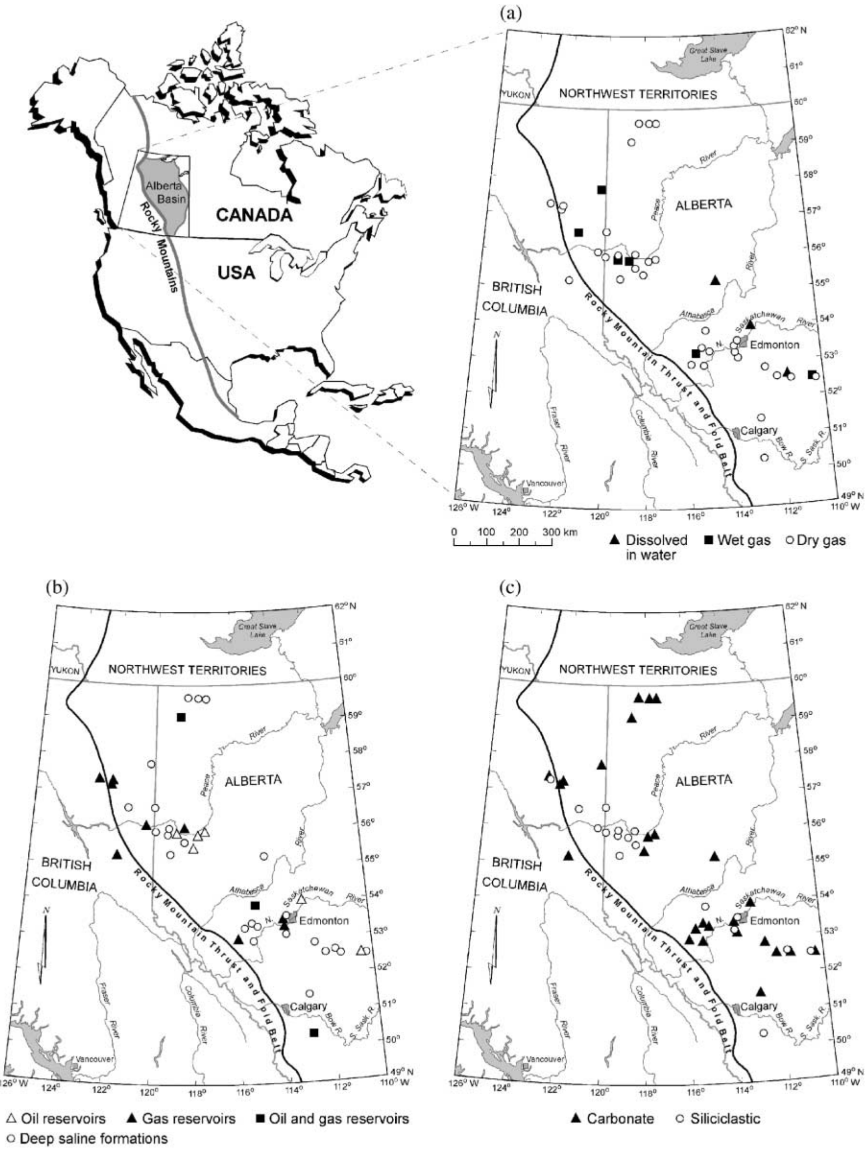


**Figure 1:** Location of acid-gas injection operations in western Canada and relevant characteristics: (a) injected acid-gas stream; (b) host unit; and (c) rock type.

composition and in situ conditions, and only in six cases it will be either in gaseous or supercritical phase. The density of the acid gas at in situ conditions varies between 205 and 728 kg/m$^3$ [11].

At 26 sites the acid gas is injected into a deep saline formation, at 18 sites it is injected into a depleted oil or gas reservoir, and at four sites it is injected in the water leg underlying a reservoir (Figure 1b). The top of the most shallow injection zone is at 705 m depth, and the bottom of the deepest one reaches 3478 m, but

TABLE 1
OPERATING RANGE OF ACID-GAS INJECTION SCHEMES IN WESTERN CANADA

| **Characteristic** | **Minimum** | **Maximum** |
|---|---|---|
| Licensed $H_2S$ (mol fraction) | 0.05 | 0.97 |
| Actual injected $H_2S$ (mol fraction) | 0.02 | 0.83 |
| Actual injected $CO_2$ (mol fraction) | 0.14 | 0.95 |
| Maximum well head pressure (kPa) | 3750 | 19,000 |
| Maximum injection rate ($10^3$ $m^3$/day) | 2 | 900 |
| Actual average injection rate ($10^3$ $m^3$/day) | 0.84 | 500.7 |
| Maximum injection volume ($10^6$ $m^3$) | 6 | 1876 |

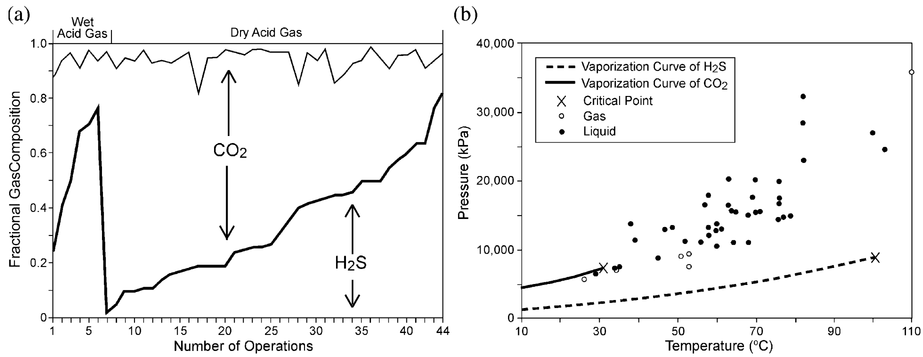


**Figure 2:** Characteristics of acid-gas injection operations in western Canada: (a) average acid-gas composition and (b) position of the $P-T$ space at in situ conditions.

most injection zones vary in depth between 1100 and 2300 m. The average depth of the actual injection interval varies between 824 and 3432 m.

The thickness of the injection formation, as defined geologically, varies between 4 and 276 m; however, the actual net pay, defined by layers with porosity and permeability adequate for injection, reaches only a maximum of 100 m. Of these, 29 are in carbonate rocks (limestone and dolostone) and 19 are in siliciclastics (sandstone and quartz arenites) (Figure 1c). In most cases shales and shaly siliciclastics constitute the overlying confining unit, the remainder of the injection zones is confined by tight limestones, evaporites and anhydrites. The cap rock thickness varies between 2 and 270 m.

The porosity of the injection zone varies between 4 and 30%, but in most cases is less than 12% (Figure 3a). The carbonate rocks generally have low porosity (less than 10%), except for carbonate reefs where porosity is as high as 22%. There is no trend in porosity for carbonate rocks. Only the porosity in siliciclastics displays a general trend of decreasing porosity with increasing depth (Figure 3a). Rock permeability varies from as low as 1 mD to as high as 4250 mD, although most values are of the order of $10^1-10^2$ mD (Figure 3b). As expected, there is no trend in permeability for carbonate rocks, but the siliciclastic rocks exhibit a trend of decreasing permeability with decreasing porosity.

The original formation pressure in the disposal zones is generally slightly subhydrostatic, which is characteristic of the Alberta basin. Two cases of above-hydrostatic pressures correspond to isolated reefal gas reservoirs. The only overpressured case corresponds to injection into a deep structural trap in the thrust

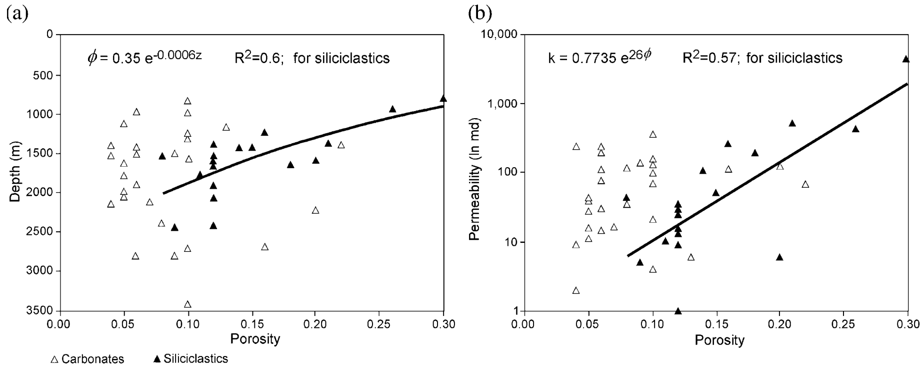


**Figure 3:** Characteristics of rock matrix at acid-gas injection sites in Western Canada: (a) porosity and (b) permeability.

and fold belt of the Rocky Mountains. In the case of acid-gas injection into depleted oil or gas reservoirs, the original reservoir pressure has been drawn down as a result of production, such that formation pressure at the start of acid-gas injection was less than the original formation pressure, sometimes significantly. From this point of view, injection into a depleted oil or gas reservoir has the advantages of injection pressures being low and of wells and pipelines being already in place [2].

Acid-gas injection could increase oil or gas recovery if it is injected to maintain reservoir pressure [12,13]. Generally, $CO_2$ can be used for enhanced oil recovery of light and medium oils (gravity greater than 27 °API, [14]), and the presence of $H_2S$ has the effect of decreasing the minimum miscibility pressure [15]. The oil gravity in the oil reservoirs used for acid-gas injection in western Canada varies between 16 and 68 °API, and the specific gravity of the native gas in gas reservoirs used for injection varies between 0.573 and 1.121. The density of the native oil or gas in these reservoirs at initial reservoir conditions (prior to production) was calculated on the basis of shrinkage factor and gas–oil ratio (GOR) for oils, and compressibility ($Z$ factor) for gases [16]. The injected acid gas is lighter than the original oil (Figure 4a), but heavier than the original gas (Figure 4b). Since these reservoirs have been produced, the drop in pressure results in the remaining oil losing some of the gas in solution, therefore becoming heavier (denser), while the remaining gas became lighter than when the pools were discovered. Given the properties of the acid gas with respect to the native oil or gas, acid-gas injection can be used for enhanced oil or gas recovery, including heavier oils than in the case of pure $CO_2$ floods, and this was the case for a few years for one of the acid-gas injection operation in northern Alberta [17]. If acid-gas injection is applied in conjunction with enhanced oil or gas recovery, the produced oil and/or gas has to be desulphurized. Thus, acid-gas injection for enhanced recovery is more suitable for sour oil and gas pools that already contain $H_2S$ and have the desulphurization infrastructure already in place, but the economics still needs to be established on a case-by-case basis.

Formation temperature varies between 26 °C at 843 m depth and 110 °C at 3432 m depth. Figure 5a shows the in situ temperature for the cases of acid-gas injection into deep saline formations. The spread in the variation of temperature with depth is due to the variability in geothermal gradients across the Alberta basin, which exhibits a trend of increasing gradients from the south, where they are as low as 20 °C/km, to the north, where they reach more than 50 °C/km. Formation waters are generally very saline, with salinity varying in a very wide range, from ~20,000 to ~341,000 mg/L (Figure 5b). Cases of relatively low-salinity water encountered at great depths are due to the influx of fresher meteoric water in recharge areas. The cases of very high salinity encountered at relatively shallow depths correspond to injection into saline formations in the vicinity of salt beds. The density of formation water, calculated on the basis of in situ pressure, temperature, and salinity [18], varies between 1007 and 1273 kg/m$^3$ (Figure 5c). The strong resemblance between Figure 5b and c illustrates the strong dependency of water density on salinity [18]. In most cases of acid-gas injection into deep saline formations, the density of the acid gas at in situ

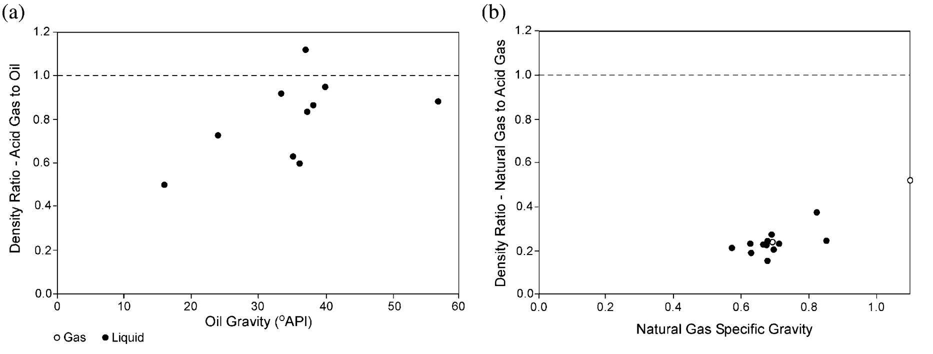


**Figure 4:** Comparison at in situ conditions between the density of acid-gas injected in oil and gas reservoirs in western Canada, and the native reservoir fluid: (a) oil and (b) gas.

conditions is approximately 50–60% of the density of the resident formation water (Figure 5d). However, in a few cases, particularly for the acid gas in gaseous phase, the density of the acid gas is as low as 10–20% of the water density. This indicates that the buoyancy force acting on the injected acid gas is quite strong, and that acid-gas migration will be mostly updip, regardless of the direction of the natural flow of formation water.

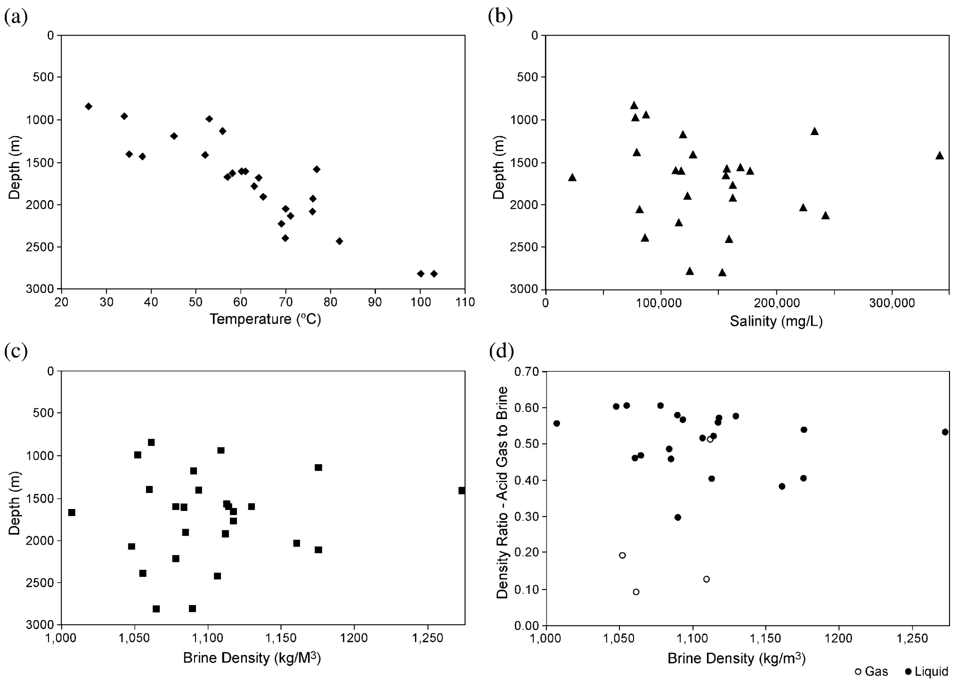


**Figure 5:** Characteristics of host aquifers for acid-gas injection operations in western Canada: (a) temperature; (b) salinity; (c) formation water density; and (d) in situ acid gas density in relation to formation water density.

If the acid gas is injected into depleted oil or gas reservoirs, the maximum volume allowed for injection is established on the basis of the respective reservoir volume, such that the acid gas will be contained within the reservoir and will not spill out. Furthermore, the pressure in the reservoir is not allowed to increase past the initial pressure, and in three cases where the operator has overpressured the reservoir, the regulatory agency suspended the operations. Thus, in the case of injection into a reservoir, the concern about potential leakage is limited only to other wells that penetrate that reservoir.

In the case of injection into deep saline formations, the pressure around the injection well is higher than the initial formation pressure. Furthermore, the plume of the injected acid gas is no more contained physically, as in the case of reservoirs. The issue of plume spread and migration becomes very important in the context of determining what existing wells may be encountered by the acid gas. Given the geological and operational complexity of these acid-gas injection operations, only detailed numerical modeling of multi-phase, multi-component flow in heterogeneous porous media can provide a prediction of the fate of the injected acid gas, particularly after cessation of injection. However, simple analytical solutions can provide an estimate of the plume spread during injection [19].

The flow of a plume of a fluid injected into a horizontal formation, immiscible with and lighter than the formation water, is driven by the bottom-hole pressure differential and buoyancy, but the plume spread and evolution are controlled mainly by the viscosity difference between the two fluids [19]. Assuming a constant injection rate $Q$, and a sharp front between the injected acid gas and the formation water, the maximum radial extent, $r_{\max}$, of the plume during injection is given by [19]

$$r_{\max}(t) = \sqrt{\frac{\lambda_c Qt}{\lambda_w \varphi \pi B}}$$

In the above relationship $\varphi$ and $B$ are, respectively, formation porosity and thickness, and $\lambda$ is the individual phase mobility, defined as the ratio $\lambda_\alpha = k_{r\alpha}/\mu_\alpha$ of relative permeability $k_r$ to fluid viscosity $\mu$, where $\alpha$ identifies each fluid ($\alpha = w$ for formation water and $\alpha = c$ for acid gas). For the cases of acid-gas injection into saline formations in western Canada, the ratio of brine to acid gas viscosities, calculated at in situ conditions [11,18], varies between 5.97 and 30.38, and the estimated radii of plume spread to date around the injection well vary between 147 and 2070 m [19]. In reality, other processes operate simultaneously, such as dissolution of the acid gas into formation water at the contact between the two, residual acid gas and water saturation, capillarity, and buoyancy in dipping strata, and some of these processes have the effect of slowing the plume spread, while other have the effect of speeding it. While better estimates for plume spread could be obtained using complex numerical simulations, this analytical solution provides a first-order estimate for identifying wells that have been or will be reached by injected acid gas during injection.

## CONCLUSIONS

Acid-gas injection in the Alberta basin in western Canada occurs at 41 sites over a wide range of formation and reservoir characteristics, acid gas compositions, and operating conditions. Injection rates in 2003 varied between 0.5 and 280 kt/yr, with an average of 25 kt/yr and a cumulative total of 1 Mt. To the end of 2003, approximately 2.5 Mt $CO_2$ and 2 Mt $H_2S$ have been successfully injected into deep hydrocarbon reservoirs and saline formations. The size of these operations is smaller by one to two orders of magnitude than of Sleipner West in the North Sea, where $CO_2$ is injected into the Utsira Formation deep under the sea bottom and which is currently the only greenhouse gas storage operation in the world, and of planned future operations for $CO_2$ storage in geological media. However, the number of the acid-gas injection operations, cumulative injection rate, diversity in injection conditions and length of operations provide valuable information that may serve as a guide for site selection and implementation of large-scale geological storage of greenhouse gases.

The subsurface characteristics of the injection sites are representative for low-porosity and low-permeability strata found usually in compacted continental sedimentary basins that have been subjected to burial and uplift, such that those in the North American mid-continent. This is in contrast to weakly compacted offshore sedimentary basins that are currently undergoing compaction and that are characterized generally by higher porosity and permeability. In the 15 years since the first acid-gas injection operation in the world started on the outskirts of the city of Edmonton, Alberta, no safety or leakage incidents have been reported. Together with the approximately 16 acid-gas injection operations in the United States, these acid-gas injection operations indicate that acid-gas injection is a mature technology that can be applied elsewhere in the world as increasingly more sour gas is produced from deep gas reservoirs.

These acid-gas injection operations constitute a commercial-scale analogue for future large-scale $CO_2$ geological storage operations to reduce $CO_2$ emissions into the atmosphere from large $CO_2$ point sources. Given that $H_2S$ is more toxic and corrosive than $CO_2$, the success of these acid-gas injection operations indicates that the technology and engineering experience developed at these operations (i.e. design, materials, leakage prevention and safety) can be easily adopted for large-scale operations for $CO_2$ geological storage. The major issues that need addressing in the near future are the long-term containment of the injected gases in the subsurface, and the safety of large-scale operations. This review of acid-gas injection operations in western Canada may help in addressing these issues.

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