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Stress Regime at Acid-Gas Injection Operations in Western Canada

Energy Resources Conservation Board

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Stefan Bachu
Kristine Haug
Karsten Michael

Alberta Geological Survey
Alberta Energy and Utilities Board

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Alberta Geological Survey
4th Floor, Twin Atria Building
4999 – 98th Avenue
Edmonton, Alberta
T6B 2X3
Canada

Tel: (780) 422-1927 (Information Sales)
Fax: (780) 422-1918
E-mail: ERCB.AGS-Infosales@gov.ab.ca
Website: www.ags.gov.ab.ca

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Executive Summary

Acid gas, a mixture of CO_2 and H_2S that is produced from sour gas reservoirs in western Canada, has been injected into deep geological formations for close to 15 years with a good safety record. Injection currently takes place at 41 locations into depleted oil and gas reservoirs, and deep saline aquifers. From this point of view, the acid-gas injection operations in western Canada constitute a commercial-scale analogue for CO_2 geological storage. A major issue in geological injection of fluids is the integrity of the injection unit, i.e., avoidance of leakage through natural or induced fractures. Regulatory agencies in western Canada impose safe limits on the injection pressure in order to maintain the pressure around the injection well below the fracturing threshold of the rocks. An evaluation of the stress regime at the acid-gas injection sites in western Canada was performed to assess the relationship between the maximum allowed wellhead injection pressures and the rock fracturing thresholds.

The stress regime in the Alberta Basin has been established in this study on the basis of 1446 hydraulic tests and on density logs in selected wells. On this basis, the minimum horizontal stress and the vertical stress have been estimated at all acid-gas injection sites. Minimum horizontal stresses increase with depth with a basin-wide average gradient of 16.6 kPa/m. Maximum vertical stresses increase with depth with a basin-wide gradient of 23.8 kPa/m. Fracture pressures increase with depth with an average gradient of 19 kPa/m, and are at all the sites greater than the minimum horizontal stress, but smaller than the vertical stress. Maximum bottom hole injection pressures are safely below the minimum horizontal stress, hence lower than the fracture pressure. Thus, there is no danger of opening existing fractures, neither, obviously, of inducing new ones.

The study has also shown that, in the case of acid or greenhouse gas injection, prescribing the maximum wellhead injection pressure according to general values established for water disposal is not sufficient because the gas most likely will not have enough bottom hole pressure to overcome the formation pressure and enter the injection unit. Thus, for acid and greenhouse gas injection in geological media, there is need to establish the maximum bottom hole and wellhead injection pressures on the basis of minimum horizontal stress to avoid opening of potential pre-existing fractures, and on the basis of gas properties at reservoir and wellhead conditions (pressure and temperature).

The current acid-gas injection operations in western Canada meet the safety criteria imposed by the need to maintain the integrity of the injection unit. However, the wide range of variability in the ratio between minimum horizontal stresses and fracturing pressures points out to the need to perform hydraulic tests at each site, rather than estimate the fracturing pressure from basin-wide fracturing gradients or numerical models. Performing carefully conducted tests will also allow site-specific determination of the minimum horizontal stress, hence of a better upper limit for the bottom hole injection pressure, to ensure that pre-existing fractures, if present, will not be opened.

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1 Introduction

Over the past decade, oil and gas producers in the Alberta Basin in western Canada (Alberta and British Columbia) (Figure 1) have been faced with a growing challenge to reduce atmospheric emissions of hydrogen sulphide (H_2S), which is produced from "sour" hydrocarbon reservoirs. Sour oil and gas are hydrocarbons that contain H_2S and CO_2, which have to be removed before the produced oil or gas is sent to markets. Since surface desulphurization through the Claus process is uneconomic and the surface storage of the produced sulphur constitutes a liability, increasingly more operators are turning to acid gas disposal by injection into deep geological formations. Acid gas is a mixture of hydrogen sulphide and carbon dioxide (H_2S and CO_2), with minor traces of hydrocarbons, that is the byproduct of "sweetening" sour hydrocarbons. In addition to providing a cost-effective alternative to sulphur recovery, deep injection of acid gas reduces emissions of noxious substances into the atmosphere and alleviates the public concern resulting from sour gas production and flaring.

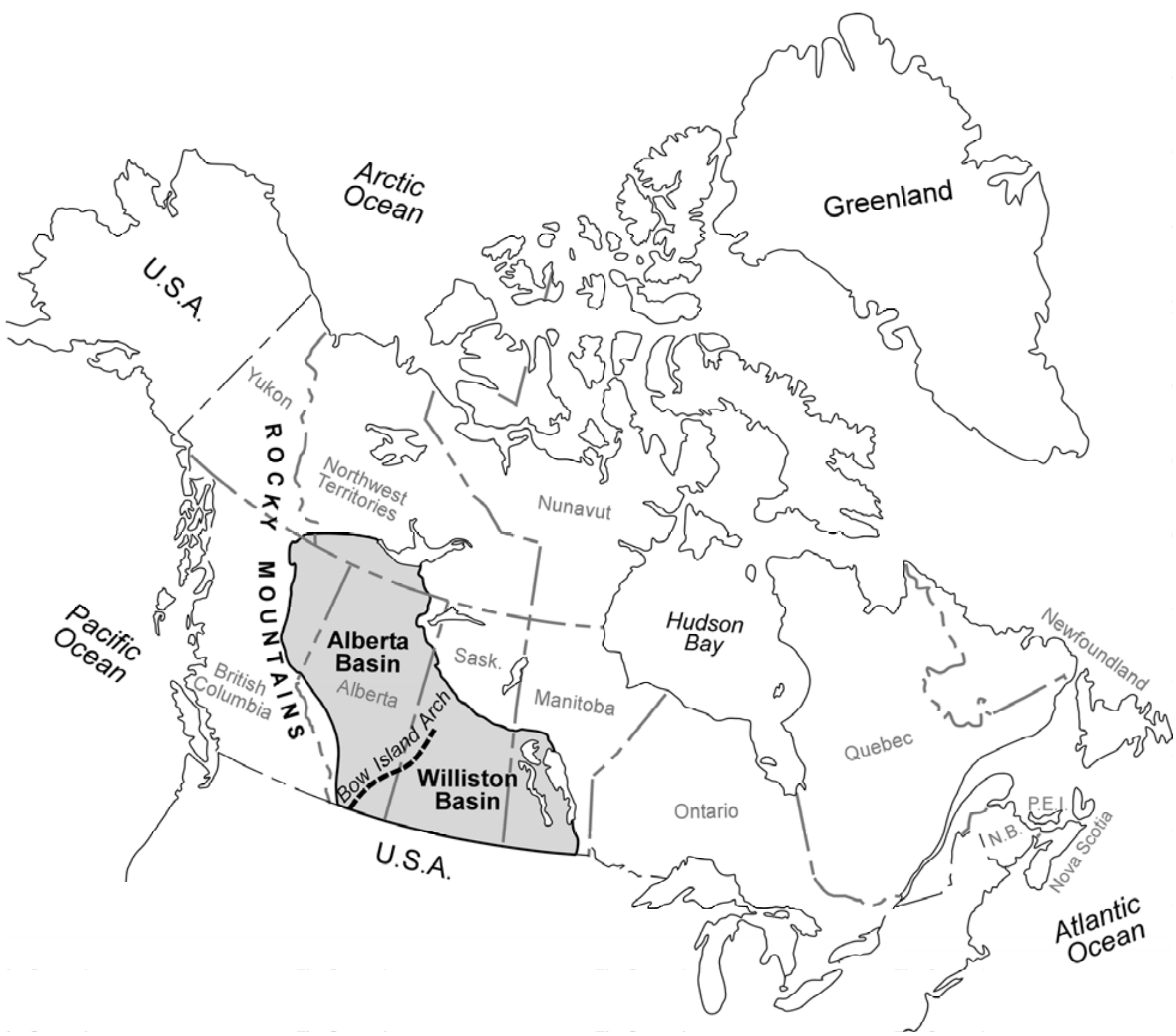


Figure 1. Location of the Alberta Basin in Canada.

The purpose of the acid-gas injection operations is to dispose of H_2S, nevertheless significant quantities of CO_2 are being injected at the same time because it is uneconomic to separate the two gases. To date, more CO_2 than H_2S has been injected into deep geological formations in western Canada. In the context of current efforts to reduce anthropogenic emissions of CO_2, the acid-gas injection operations in western Canada represent a commercial-scale analogue to geological storage of CO_2. The latter is an immediately-available and technologically-feasible way of reducing CO_2 emissions into the atmosphere that is particularly suited for land-locked regions located on sedimentary basins, such as the North American mid-continent. Large-scale injection of CO_2 into depleted oil and gas reservoirs and into deep saline aquifers is one of the most promising methods of geological storage of CO_2, and in this respect it is no different from acid-gas injection operations. However, before implementation of greenhouse gas geological storage, a series of questions need addressing, the most important ones relating to the short- and long-term fate of the injected CO_2. Thus, the study of the acid-gas injection operations in western Canada provides the opportunity to learn about the safety of these operations and about the fate of the injected gases, and represents a unique opportunity to investigate the feasibility of CO_2 geological storage.

In the 15 years since the first operation in the world started injecting acid gas into a depleted reservoir on the outskirts of the city of Edmonton, Alberta, no safety incidents have been reported. The success of these acid-gas injection operations indicates that the engineering technology for CO_2 geological storage is in a mature stage and ready for large-scale deployment. 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. Maintaining the integrity of the injection formation and of the confining unit is essential in any geological disposal operation of liquid and hazardous wastes in order to prevent leakage through natural or induced fractures. In that respect, the regulatory agencies in western Canada impose safe limits on the injection pressure in order to maintain the pressure around the injection well below the fracturing threshold of the rocks. However, in the absence of reliable tests, these limits are based on generalized tables of values. The purpose of this study is to evaluate the stress regime at the acid-gas injection sites in western Canada to assess the relationship between the maximum allowed wellhead injection pressures (WHIP) and the rock fracturing thresholds and geomechanical properties at these sites.

2 Acid-Gas Injection Operations in Western Canada

2.1 Status

The first acid-gas injection operation in Alberta was approved in 1989 and started in January 1990. To date, 48 applications for injection of acid gas produced at 42 different gas plants have been approved in western Canada (35 in Alberta and 7 in British Columbia). Their distribution is shown in Figure 2. The seeming inconsistency between the number of applications and number of injection operations stems from the fact that in several places injection took or takes place in different units at the same location, or the composition of the injected gas stream is different, in which case an application has to be

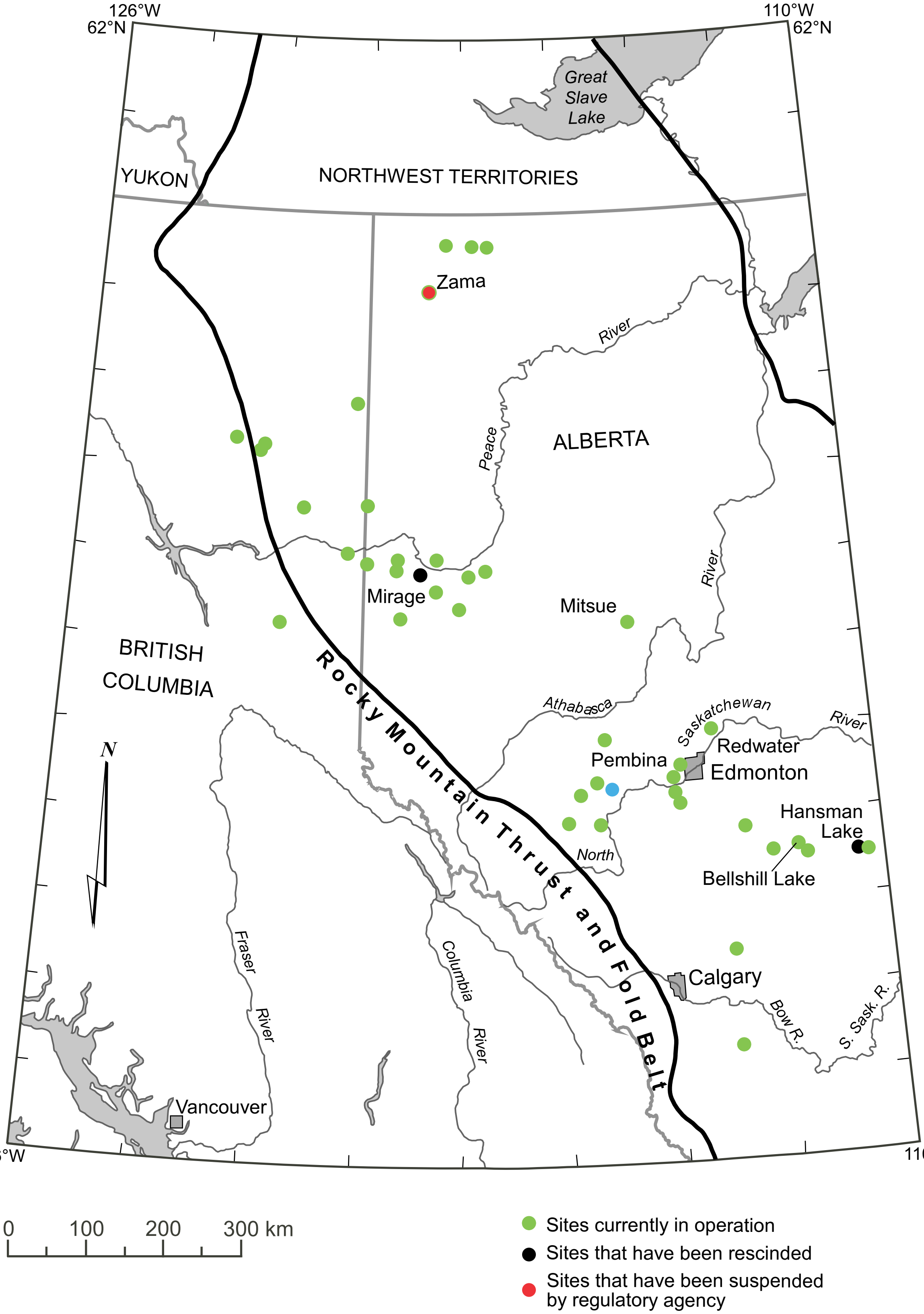


Figure 2. Location and status of the acid-gas injection operations in the Alberta Basin, Canada, at the end of 2003.

submitted and approved for each case. For clarification, in the following, different acid gas sources at different gas plants and land locations are designated as acid gas operations, and the injection cases themselves are referred to as injection sites. The operations with multiple sites are Zama with 4 and Gordondale with 2 in Alberta, and Norcen Caribou and West Stoddart in B.C. with 2 sites each. At most sites injection takes place through a single well. At a few sites injection takes place through two or three wells, and at two sites injection takes place through multiple wells.

There is no obvious historical trend in the use of acid-gas geological disposal in western Canada, although a few very large operations have been approved recently (Figure 3). One may initially expect an increase in operation size as knowledge and technology advances, but the lack of an historical trend is more a reflection of economic and geological considerations than of technological know-how.

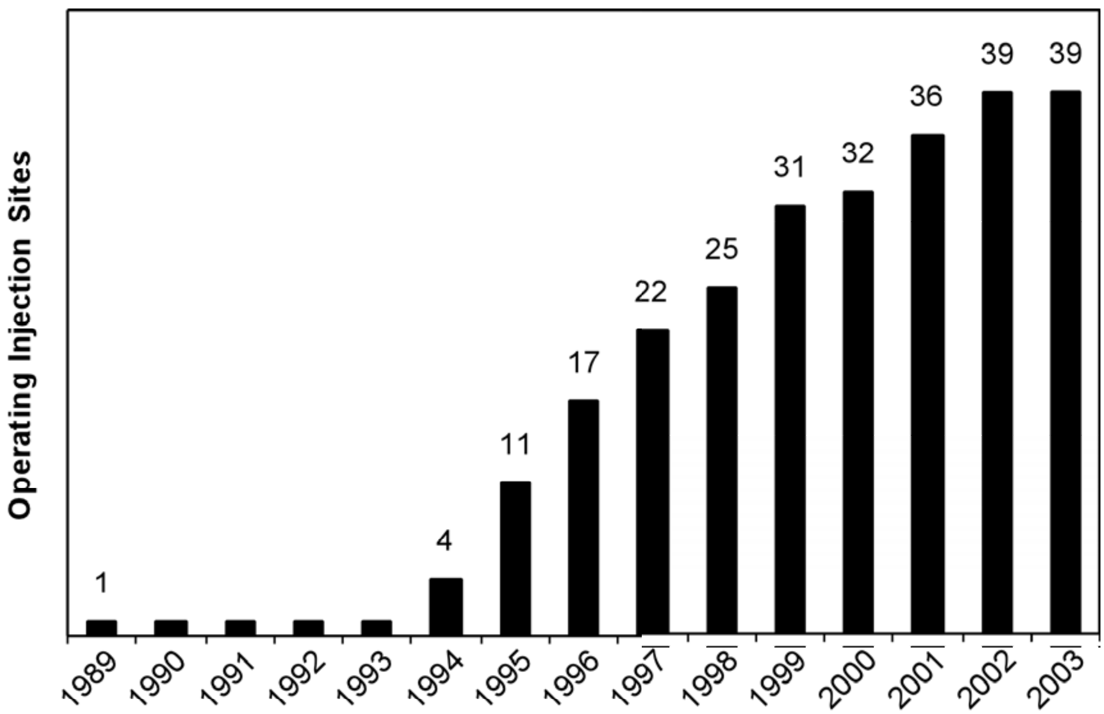


Figure 3. Histogram of active acid-gas injection operations in the Alberta Basin.

Of the 42 approved operations, 39 were active as of December 2003, injecting acid gas at 42 different sites. One operation in the Pembina field west of Edmonton, Alberta, although approved, was never implemented by the operator and was subsequently rescinded. Two other operations, also in Alberta at Hansman Lake and Mirage (Figure 2), ceased injection and have been rescinded in 1997 and 1998, respectively. Injection was terminated either because the injection volumes reached the approved limit, and the operator moved to another site or injection formation, or because the gas plant producing the acid gas was decommissioned, with the sour gas being processed at another, nearby plant. Injection into the Triassic Halfway Formation at the Gordondale operation in western Alberta was rescinded in 1999 because it reached the approved reservoir limit, and it was immediately replaced by injection into the underlying Permian Belloy

Formation. At Zama in northern Alberta (Figure 2), an operation with multiple sites, injection into reefal carbonate oil reservoirs was successively suspended in 1998, 2000 and 2003 by the regulatory agency because the respective injection reservoirs became over pressured beyond the initial reservoir pressure. Injection at Zama currently takes place in the Keg River aquifer. At 26 sites, approval was given to inject the acid gas into deep saline aquifers in regional-scale flow systems confined by regional-scale aquitards. At 18 sites, injection took or takes place in depleted oil and/or gas reservoirs, and at 4 sites the acid gas is injected into the underlying water leg of depleted oil and gas reservoirs.

The average injection depth varies between 824 and 3432 m. At 29 sites injection takes place in carbonate rocks and at 19 sites in siliciclastics. In most cases shales and shaly siliciclastics constitute the overlying confining unit (top seal). The remainder of the injection zones are confined by tight limestones, evaporites and anhydrites. The original formation pressure is generally subhydrostatic with respect to freshwater, which is characteristic of the Alberta Basin (Bachu, 1999), and varies between 5915 and 35,860 kPa (Figure 4). The cases where the pressure seems to be slightly above hydrostatic correspond to high salinity formation waters. If the real formation water density is taken into account, then pressure at all sites is hydrostatic or less, except for the case of Sukunka in the Foothills in northeastern British Columbia, where the injection reservoir is slightly overpressured. In the case of acid gas injection into depleted oil or gas reservoirs, the original reservoir pressure was 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, reaching as low as 1170 kPa. Production-induced drawdown occurs also in some cases of injection into an aquifer underlying an oil pool, and into an aquifer located very close to an oil pool. In 10 cases the formation pressure at start up was below the critical pressure of CO_2 (the critical points are T=31.1°C and P=7,380 kPa for CO_2 and T=100.2°C and P=8,963 kPa for H_2S).

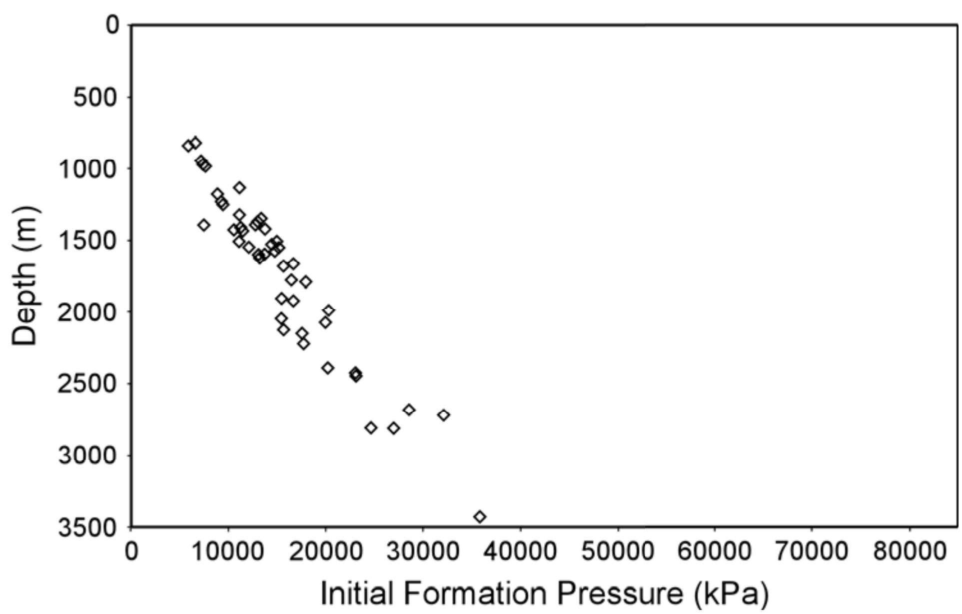


Figure 4. Variation with depth of initial formation pressure at acid-gas injection sites in the Alberta Basin.

2.2 Requirements Regarding Injection Pressure

In Alberta, the Oil and Gas Conservation Act requires that operators apply for and obtain approval from the Alberta Energy and Utilities Board (EUB), the provincial regulatory agency, to dispose of acid gas. Applications for acid gas disposal need to conform to the specific requirements listed in Chapter 4.2 of Guide 65 that deals with applications for conventional oil and gas reservoirs (EUB, 2000). Similarly, in British Columbia (B.C.) operators have to apply for approval to the B.C. Oil and Gas Commission, whose requirements are modeled after those in Alberta. The regulatory agencies review the applications to maximize conservation of hydrocarbon resources, minimize environmental impact and ensure public safety (Keushnig, 1995; Longworth *et al*., 1996).

The specific location of an acid-gas injection well is based on a general assessment of the regional geology and hydrogeology, which is designed to evaluate the potential for leakage (Longworth *et al*., 1996). In addition, the regulatory agencies require that environmental concerns must be addressed, such as injection-formation suitability, wellbore integrity, operating parameters (to ensure formation and well integrity) and optimization of the injection space, which is considered to be a limited resource. Of particular importance are potential migration pathways from the injection zone to other formations, shallow groundwater and/or the surface.

To avoid acid gas migration through fractures, the injection zone must be free of natural fractures and the bottom hole injection pressure must be below a certain threshold to ensure that fracturing is not induced. Since the bottom hole injection pressure (BHIP) is hard to monitor and difficult to control, regulatory agencies set operating limits on the wellhead injection pressure (WHIP). The relationship between the two pressures is given by:

$$P_{BH} = P_{WH} + \int_0^D \rho_f \cdot g dz - \Delta P_{well} \qquad (1)$$

where P is pressure, ρ_f is fluid density, g is the gravitational constant (9.81 m/s^2), z is vertical depth along the wellbore, D is the depth of perforations at the entry into the injection formation (aquifer or reservoir), ΔP_{well} represents the pressure loss in the well due to viscous resistance to flow, and the subscripts $_{BH}$ and $_{WH}$ stand for bottom hole and wellhead, respectively. Basically, relation (1) shows that the bottom hole injection pressure is given by the sum of the wellhead injection pressure, the static weight of the fluid column in the well, and the (negative) friction losses in the tubing. In the case of acid gas, friction losses are negligible because of the very low viscosity of the gas.

The maximum bottom hole injection pressure (BHIP) is usually set at 90% of the rock fracturing pressure (P_f). The maximum wellhead injection pressure (WHIP) is then established on the basis of the maximum BHIP considering the hydrostatic weight of the acid gas column in the well and friction losses. Thus, setting the maximum wellhead injection pressure involves two steps:

1. Determination of the rock fracturing threshold (fracturing pressure); and
2. Determination of the hydrostatic weight of the column of acid gas in the well and of friction losses.

In the case of water injection, which is almost incompressible (i.e., of constant density ρ_w), Eq. (1) simplifies to:

$$P_{BH} = P_{WH} + \rho_w \cdot gD - \Delta P_{well} \tag{2}$$

By establishing P_{BH} at less or equal to 90% of the fracturing pressure (P_f), the maximum wellhead pressure (P_{WH}) can be easily back-calculated from Eq. (2). For water injection, in the absence of information about the rock fracturing pressure, the wellhead injection pressure is limited by the regulatory agencies using pressure-depth correlations, based on basin-wide statistical data for the Alberta Basin. Table 1 below presents the maximum WHIP as a function of depth used by EUB for the disposal of aqueous fluids (EUB, 1994).

Table 1. Maximum wellhead injection pressure (WHIP) for the geological disposal of liquid wastes in Alberta, used by the regulatory agency as a guide in the absence of site-specific information (EUB, 1994).

Depth Interval (m)	Wellhead Pressure (kPa)	Depth Interval (m)	Wellhead Pressure (kPa)
401 – 450	3000	1501 – 1551	4450
451 – 500	3200	1551 – 1600	4500
501 – 551	3300	1601 – 1650	4550
551 – 600	3450	1651 – 1700	4600
601 – 650	3550	1701 – 1750	4650
651 – 700	3600	1751 – 1800	4700
701 – 750	3650	1801 – 1850	4800
751 – 800	3700	1851 – 1900	5200
801 – 850	3750	1901 – 1950	5650
851 – 900	3800	1951 – 2000	6000
901 – 950	3850	2001 – 2050	6400
951 – 1000	3900	2051 – 2100	6750
1001 – 1050	3950	2101 – 2150	7150
1051 – 1100	4000	2151 – 2200	7550
1101 – 1150	4050	2201 – 2250	7950
1151 – 1200	4100	2251 – 2300	8350
1201 – 1250	4150	2301 – 2350	8750
1251 – 1300	4200	2351 – 2400	9150
1301 – 1350	4250	2401 – 2450	9500
1351 – 1400	4300	2451 – 2500	9900
1401 – 1450	4350		
1451 – 1500	4400		

Above 400 metres use wellhead pressure (kPa) = 7.5 x depth (m)
Below 2500 metres use wellhead pressure (kPa) = 4 x depth (m)

The limitations on WHIP presented in Table 1 are based on the assumption that the injected fluid is an aqueous solution with a constant density of ~1000 kg/m^3, hence a hydrostatic gradient of ~10 kPa/m. However, acid gas has a much smaller density, and application of these limiting values for WHIP would not provide enough bottom hole pressure for the acid gas to overcome the formation pressure and enter the disposal unit. Only for injection into depleted hydrocarbon reservoirs could the maximum WHIP as indicated in Table 1 be used, and even then only up to the point when the reservoir is partially repressurized. Thus, this procedure is not applicable to acid gas injection and Eq. (1) should be used.

The concept of limiting the maximum WHIP is evolving, and lately regulatory agencies are further limiting the maximum BHIP in the case of injection into depleted oil or gas reservoirs at no more than the initial reservoir pressure, and sometimes at 90% of this value. The reason is that the integrity of the reservoir may be damaged through the cycle of depressuring (during production) and repressuring (during injection). In the case of injection into aquifers, where the injection pressure has to be greater than the formation pressure, the limitation of BHIP at 90% of the fracturing pressure still applies.

On the other hand, the wellhead injection pressure is provided by the compressors at the outlet from the separation unit in the gas plant, taking into account friction losses in the pipeline. Economic and operating considerations limit the size of these compressors, and in some cases the maximum WHIP is dictated by these considerations, as long as it is less than the value obtained using the relationship (1) between BHIP and WHIP. The lesser of these values, if indicated by the operator, is set by the regulatory agency as a licensed operating parameter. Thus, maximum WHIP should be consistent with formation fracturing pressure and equipment specifications.

2.3 Practices for Establishing Fracturing Pressure, BHIP and WHIP

In the case of disposal wells, EUB regulations provide that the formation fracturing pressure may be determined by step-rate injectivity tests, in situ stress tests, mini-frac tests or reliable offset fracture/injectivity data (EUB, 1994). If such information is available, then it is used to determine the maximum WHIP such that the BHIP is at all times less than 90% of the fracturing pressure (P_f).

In the specific case of acid-gas injection operations, operators used a variety of means to estimate the fracturing pressure (P_f). In ten cases the operator performed an injectivity test in the injection well itself. In four other cases the operators estimated the fracturing pressure (P_f) on the basis of tests run in the corresponding injection unit in neighboring wells (mini-frac test, fracture treatment and acid job). In 28 cases the fracturing pressure was estimated on the basis of fracture gradients, and finally in six cases no value or estimate is provided. It should be noted here that operators tend to be conservative in their estimations of fracture gradients (i.e., their estimates tend to be on the low side), thus adding an extra element of safety in their assessment. Figure 5 shows the variation with depth of the fracturing pressure (P_f) as provided by operators in their applications to the regulatory agencies, showing an increase with depth with an average gradient of 19 kPa/m in the range of 14,000 to ~61,000 kPa.

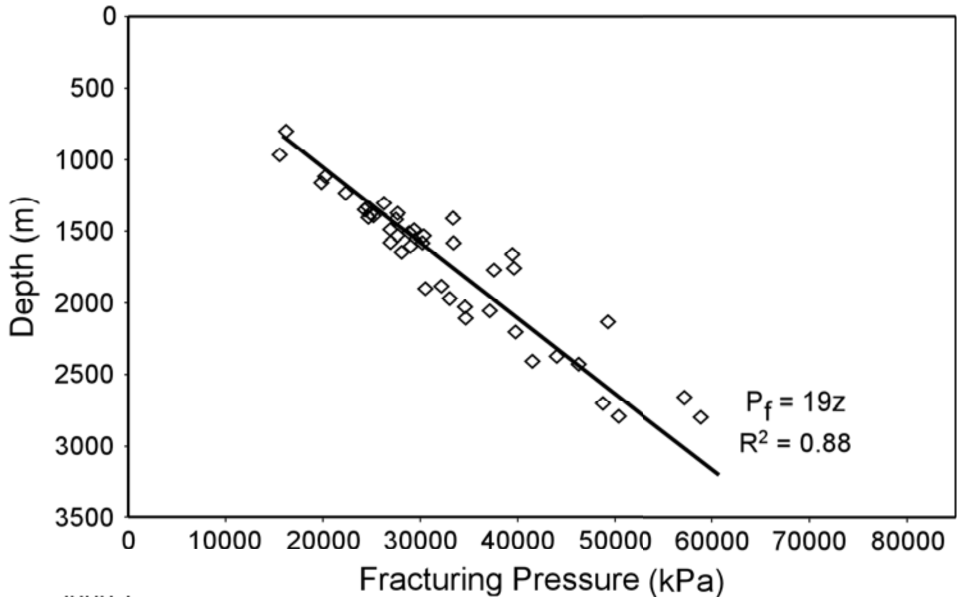


Figure 5. Variation with depth of fracturing pressure at acid-gas injection sites in the Alberta Basin, as indicated by operators.

In most cases where the fracture gradient was used to estimate the fracturing pressure, the operator did not provide the source of the data. In three cases the operator used the following relationship between vertical stress (S_V) pore (or fluid) pressure (P), and breakdown pressure (P_b) to estimate the fracturing gradient.

$$P_b > \frac{\nu}{1-\nu}(S_V - P) + P \qquad (3)$$

where ν is Poisson's ratio (a characteristic of rock strength). Here the breakdown pressure (P_b) is equivalent to the fracturing pressure (P_f). In applying relation (3), the following assumptions were made: the principal stress is vertical, the horizontal stress field is isotropic, and stress increases linearly with depth. Literature values were used for the various variables and parameters appearing in relation (3).

At three sites in Alberta, Bellshill Lake, Mitsue and Redwater (Figure 2), acid gas is dissolved in water at surface, resulting in "sour water", prior to injection at depths less than 1000 m. As a result, relation (2) can be applied to estimate the bottom hole pressure (P_{BH}). If friction losses are neglected, the sum of the wellhead injection pressure and the static weight of the water column provides an upper estimate of P_{BH}, as in the case of Mitsue. The Redwater and Bellshill Lake operations were originally water disposal operations that have been subsequently approved to co-inject acid gas dissolved at very low concentrations in very large volumes of water ("sour water"). Injection at these operations takes place alternatively through 17 wells at Bellshill Lake and 47 wells at

Redwater. Because the water has a much larger capacity for dissolved acid gas than actually used, and because the reservoirs are underpressured, there are no safety issues relating to the possibility of a well blowout. Hence, these operations did not initially require an acid gas application. Furthermore, injection at Redwater is occurring into a massive oil pool that has been in production for a very long time. The reservoir is currently underpressured and injection takes place gravitationally, i.e., no injection pressure is needed at the wellhead, and the water is just flowing down the well. Similarly at Mitsue, sour water (i.e., acid gas dissolved in water) is injected gravitationally.

Acid gas is injected at all other sites. In 23 cases operators used reservoir engineering methods to estimate the pressure needed at the screen to push the acid gas into the formation ("sand-face" pressure, P_{sf}), and this is established as the bottom hole injection pressure. Then the wellhead injection pressure should be calculated on the basis of Eq. (1). However, both CO_2 and H_2S are highly compressible gases whose density and viscosity are strongly dependent on temperature and pressure, as illustrated in Figure 6 below for CO_2.

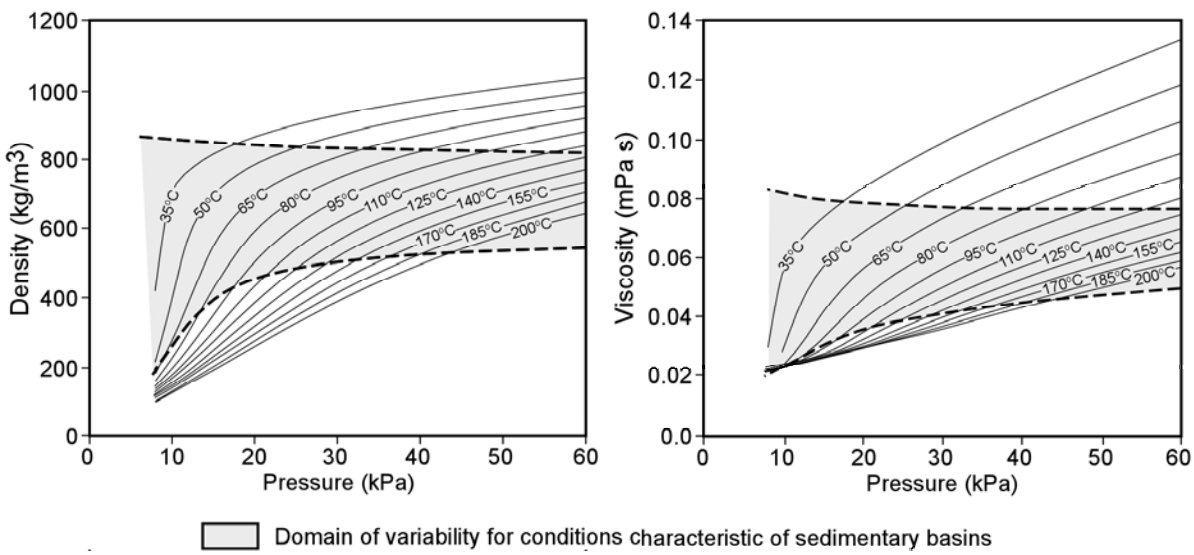


Figure 6. Variation of CO_2 density and viscosity with pressure and temperature for conditions characteristic of sedimentary basins.

Because of the high compressibility of the acid gas, determination of the last two terms in relation (1) is very complex and difficult because:

- The wellhead injection temperature and pressure vary, depending on operating conditions;
- The temperature downhole increases with depth as a result of the local geothermal gradient;
- The injected acid gas exchanges heat with the surrounding rock through the well tubing, isolating fluid, casing and cement;
- Friction losses depend on acid gas density and velocity;
- Density in turn depends on all the previous parameters;
- The acid gas may change phase in the tubing (e.g., gas to liquid).

Furthermore, phase changes within the wellbore may be especially significant in the case of injection into depleted reservoirs, because, at least in the beginning of injection, reservoir pressures can be so low as a result of production (lower than the wellhead pressure plus the hydrostatic weight of the acid gas column in the well), that, although the acid gas is injected in a liquid or supercritical form at the wellhead, it changes to gas in the reservoir. With time, as the reservoir pressure increases as a result of injection, the gas becomes supercritical again, and these complications due to phase changes won't occur anymore.

Thus, operators usually calculate the acid gas density that corresponds to the sand-face pressure (P_{sf}), i.e., BHIP, and formation temperature. The weight of the acid gas column (Eq. 1) is approximated by the weight of a column of average acid-gas density, the average being taken between the "sand-face" density and the density of acid gas at surface, thus approximating Eq. (1) with Eq. (2) to obtain the wellhead injection pressure. The maximum WHIP is then obtained by substituting the sand-face pressure (P_{sf}), i.e., BHIP, with a value equal to 90% of the fracturing pressure (P_f).

Since determination of the hydrostatic weight of the acid gas column in the wellbore is so complex and difficult, a more conservative approach is sometimes taken with regard to the maximum WHIP by considering the weight of a column of water rather than acid gas, thus reducing Eq. (1) to Eq. (2). This is the case of the Long Coulee and Pembina – Wabamun II sites.

In 11 cases, operators performed fully-blown numerical reservoir simulations for multi-component, multi-phase flow for a range of acid gas composition, pressures and temperatures, to establish both the bottom hole and the wellhead pressures (BHIP and WHIP). It should be clarified here that reservoir simulations were performed by operators in more than these 11 cases, particularly for injection into depleted reservoirs, to determine injection volumes, strategies, and other parameters. However, maximum BHIP and WHIP were provided on the basis of reservoir simulations only in these 11 cases. Finally, in nine cases, the operator did not specify how maximum BHIP and WHIP were calculated. In 14 of the 46 cases of acid gas injection (i.e., excluding Redwater and Bellshill Lake), the regulatory agency specified both the maximum BHIP and WHIP, and in all others only the maximum WHIP.

At two sites, Parkland-Kiskatinaw and Talisman-Sukunka, the maximum BHIP (sand-face pressure) was set by the regulatory agency at the initial reservoir pressure or less. This is particularly important in the case of the Sukunka reservoir, which was initially over pressured. At two sites, Brazeau-Nisku and Gordondale Halfway, the regulatory agency set a limit on the final reservoir pressure (at abandonment) to be no more than the initial reservoir pressure. At all other sites the maximum BHIP is set in relation to the fracturing pressure.

The final maximum WHIP was set by regulatory agencies through a combination of maximum BHIP as determined above, and equipment limitations, and varies between 3,750 and 19,000 kPa. In the cases where the maximum WHIP was modified from the values originally derived on the basis of rock integrity limitations, the maximum BHIP was recalculated following the same process in reverse (see Eq. (1)). Figure 7 shows the variation with depth of the maximum bottom hole injection pressure at the acid-gas injection sites in western Canada as estimated by operators or regulatory agencies. Maximum BHIP varies between 6,193 and 39,000 kPa and is always lower than the fracturing pressure (as expected), on average quite low at 62% of P_f. In one case maximum BHIP is as high as 90% of P_f and in another case, rescinded, it was 93% of P_f. In three cases, the maximum BHIP is actually lower than the initial formation pressure (P_i), and in another 8 cases the maximum BHIP is set at or very close to the initial pressure. In all other cases maximum BHIP is greater than P_i, reaching as high as twice the initial pressure. Figure 8 illustrates the relation between maximum BHIP on one hand, and the initial formation pressure (P_i) and the fracturing pressure (P_f) as indicated by operators or set by the regulatory agency.

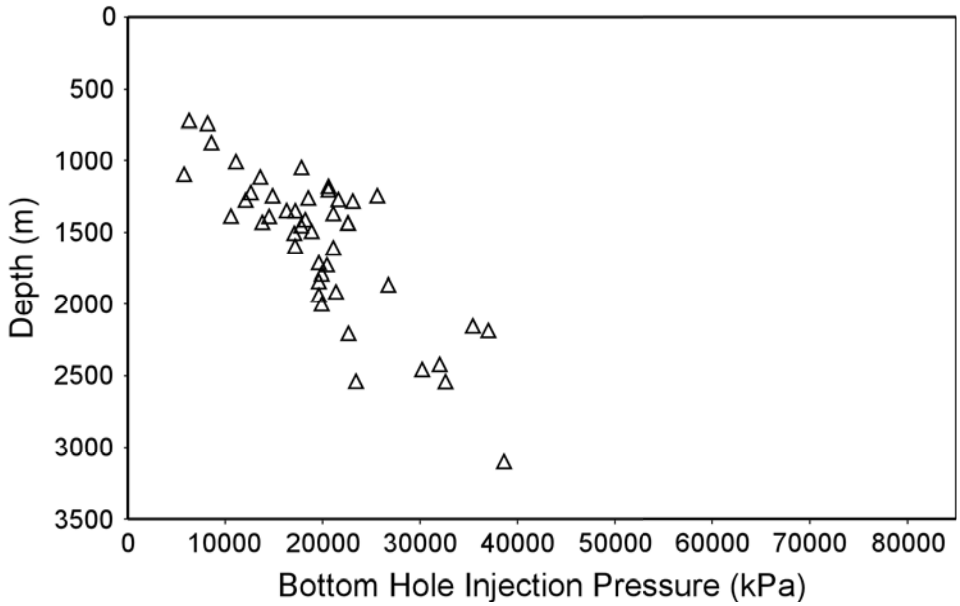


Figure 7. Variation with depth of estimated maximum bottom hole injection pressure (BHIP) at acid-gas injection sites in the Alberta Basin.

The maximum wellhead injection pressure (WHIP) for acid gas injection was established at each site on the basis of equipment potential (or limitations) and the need to ensure the integrity of the injection unit (i.e., maximum BHIP). In almost all cases it is greater than the maximum wellhead injection pressure that is recommended in Table 1 for disposal of aqueous fluids. The reason is, as explained previously, that there is need for higher wellhead pressure to push the lighter acid gas into the disposal unit than would be needed in the case of water disposal into the same unit. For comparison, Figure 9 presents the relation between the maximum WHIP for water disposal (as per Table 1) and for acid gas disposal. The three cases where the maximum WHIP for acid gas disposal is less than the maximum WHIP for water disposal correspond to acid gas disposal into depleted gas reservoirs, where the reservoir pressure is sufficiently low to allow injection. The sour water injection sites (Bellshill Lake, Mitsue and Redwater) are not represented on this figure.

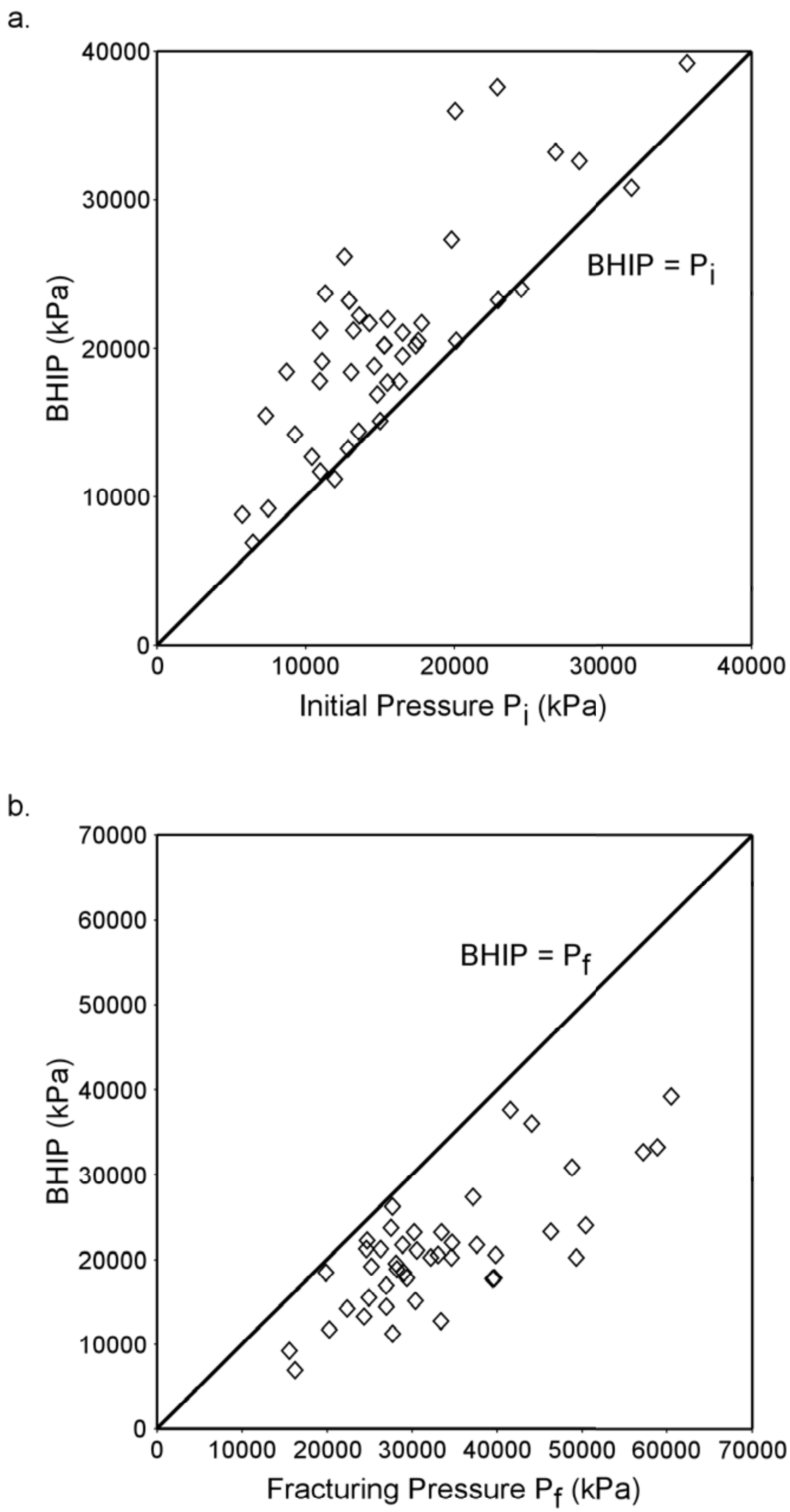


Figure 8. Comparison between the maximum bottom hole injection pressure (BHIP) and:
a) initial pressure (P_i), and b) fracturing pressure (P_f) at the acid-gas injection sites in the Alberta Basin.

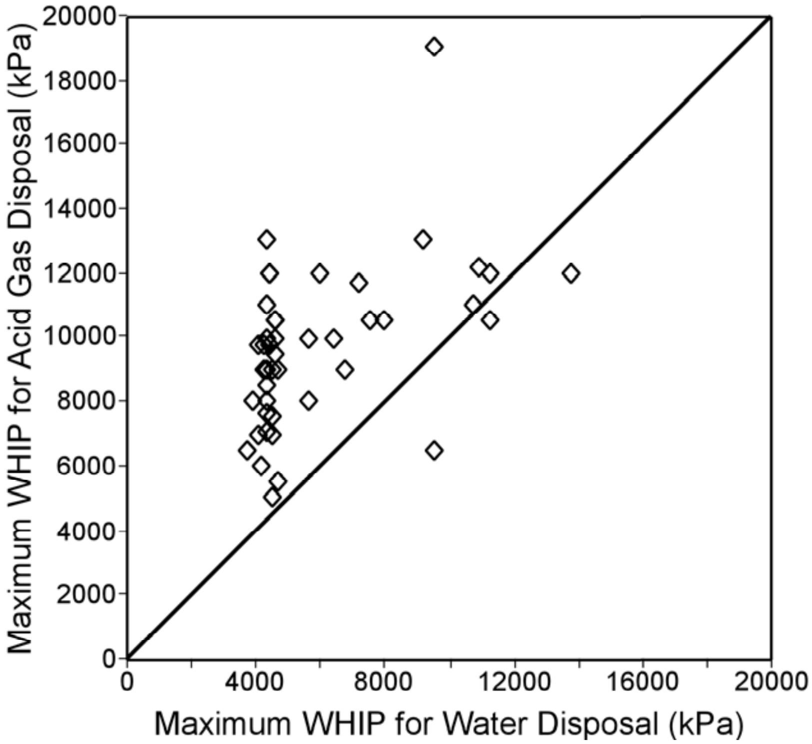


Figure 9. Relation between the maximum WHIP for water disposal in the Alberta Basin (EUB, 1994) and for acid gas injection.

3 Stress Regime in the Alberta Basin

3.1 Determination of the Stress Regime in a Sedimentary Basin

Knowledge of the stress regime in a sedimentary basin is important because stresses affect sediment compaction and rock fracturing. Prevention of the latter is a requirement during both drilling and injection of liquid wastes, be they in aqueous solution or other fluids such as acid and greenhouse gases, because fractures constitute a leakage path that would allow upward migration of fluids. Stresses are tensorial in nature and are characterized by the three principal components, σ_1, σ_2 and σ_3, which are orthogonal, and their orientations. By definition, one of the principal stresses must intercept free surfaces, such as the ground surface, at right angles. Thus, in the case of divergent sedimentary basins (e.g., foreland, intra-cratonic, platform-margin) with gentle surface relief, a basic assumption is that the ground surface is semi-planar and horizontal; hence the principal stress directions are approximately vertical and horizontal. In this case, the principal stresses are denoted by S_V for the vertical stress, and S_{Hmin} and S_{Hmax} for the smaller and larger horizontal stresses, respectively. This assumption is not valid in the case of convergent sedimentary basins (e.g., in subduction areas, intramontane), in the vicinity of major fault zones that deflect stresses, around salt domes or in overthrust and deformed zones. The assumption of vertical and horizontal principal stresses applies to the Alberta Basin east of the Rocky Mountain Deformation Front, and to the Williston Basin for that matter. In most sedimentary basins S_{Hmin} is less than S_V, and indeed previously published stress magnitude measurements in the Alberta Basin indicate that the smallest principal stress, σ_3, is horizontal (i.e., $\sigma_3 = S_{Hmin}$) except possibly in parts of the foothills and at shallow depths in northeastern Alberta (Bell and Babcock, 1986; Bell *et al*., 1994; Bell and Bachu, 2003).

Stress magnitudes have to be measured or estimated. The vertical stress (S_V) at any point in the basin is equivalent to the weight of the overburden. Integration of the density log taken during drilling will provide the load (vertical stress) to depth (D), according to:

$$S_V = \int_0^D \rho_b dz \tag{4}$$

where ρ_b is the rock density. Density logs that are used for estimating S_V should be as complete as possible and record little caving. In practically all wells there is an upper unlogged interval and an average rock density has to be assumed. Figure 10 shows, for illustration, the density log and the calculated vertical stress in well 9-10-2-10W4. If necessary, rock density for unlogged intervals can be derived from velocity analyses of seismic records. An increase in the gradient of the vertical stress with increasing depth observed in many sedimentary basins can be easily explained by compaction (e.g., Edwards *et al*., 1998).

The smaller horizontal stress (S_{Hmin}) can be estimated through various means. One way is using micro- and mini-fracture tests, leak-off tests and massive hydraulic fracture records (Bell, 2003; Zoback *et al*., 2003). The accuracy of the estimates decreases from micro-fracture tests to massive hydraulic fractures. Micro-fracture tests involve initiating a hydraulic fracture within a short packed-off interval by slowly injecting a small volume (~1 m^3) of a low-viscosity fluid (e.g., water), and opening and closing the fracture several times until a consistent closure pressure is obtained. If the fracture closure pressure is less than the overburden load (S_V), then this pressure is equated with the smallest principal stress, i.e. S_{Hmin} (Gronseth and Kry, 1983). Mini-fracture tests are similar to micro-fracture tests and typically involve a relatively high-rate injection of viscous fluids in excess of 10 m^3 (e.g., McLellan, 1988). The magnitude of S_{Hmin} can be equated with fracture closure pressures interpreted from pressure versus time records, but these tests measure the average in situ stress over a larger rock volume than the micro-fracture tests. Previous work in western Canada has shown that closure pressures from micro- and mini-fracture tests are practically indistinguishable (Woodland and Bell, 1989).

In a leak-off test, which are fracture tests run in an open hole by exerting pressure on the drilling fluid, pressure is raised slowly until the pressure build-up ceases to be linear (Figure 11), at which time it is believed that a small volume of fluid has begun to leak-off into the formation. These tests are similar to small-volume hydraulic fracturing stress tests. If a fracture (natural or induced) normal to the S_{Hmin} direction existed prior to the test, then the leak-off pressure (P_{lo}) is approximately equal to S_{Hmin}. The minimum horizontal stress keeps the fracture closed, and the fracture opens, allowing fluid to leak, when pressure equals the minimum stress.

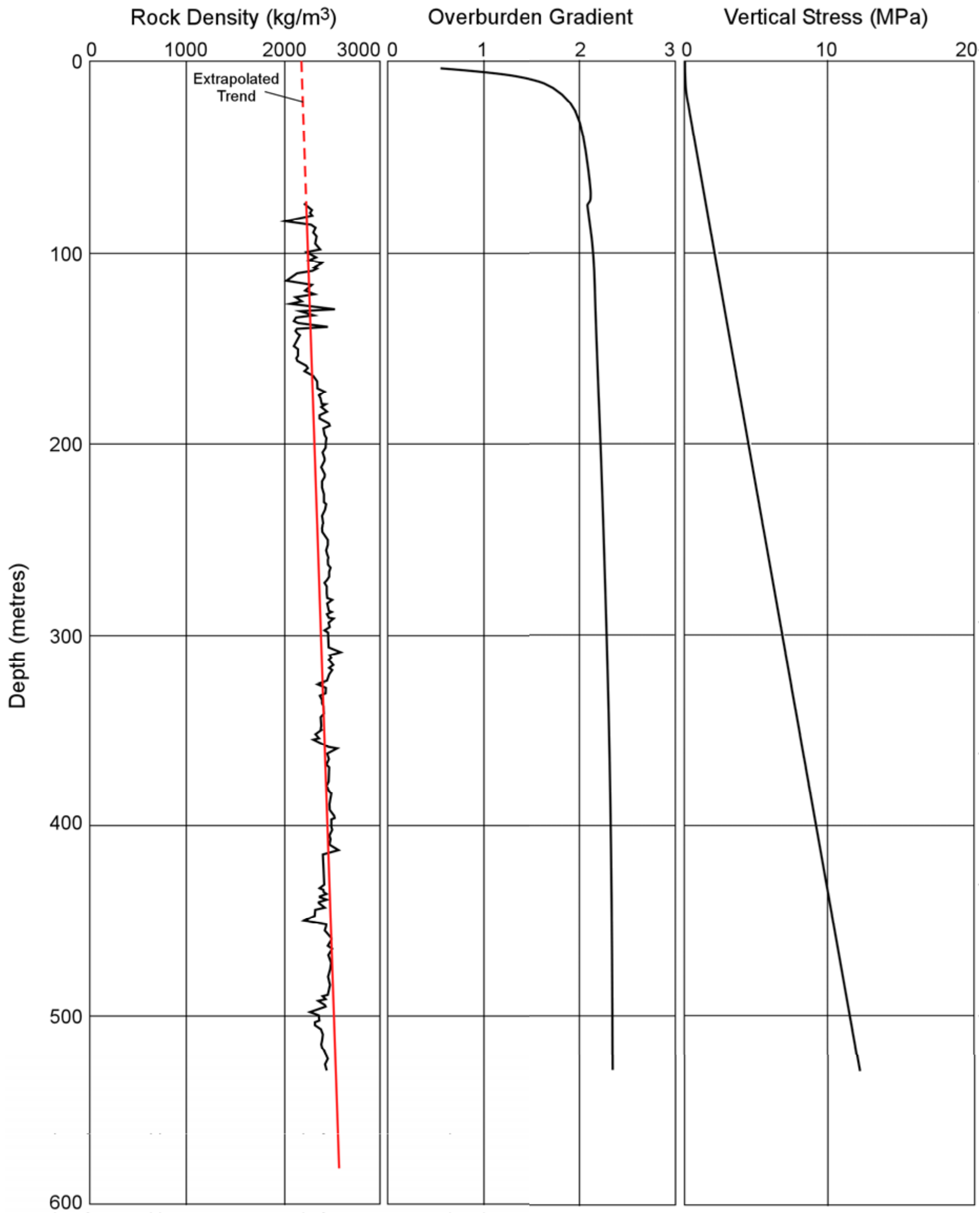


Figure 10. Example of a density log and of the corresponding (calculated) variation of vertical stress with depth in well 9-10-2-10W4.

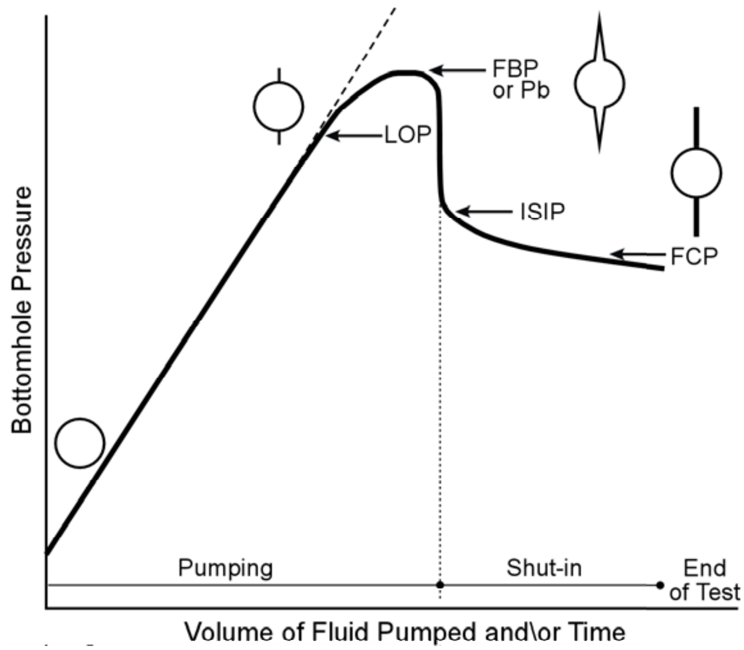


Figure 11. Diagrammatic representation of pressure variation during a fracturing test, showing the various phases in the evolution of a fracture. The following designations are used to indicate various characteristic pressures: LOP: leak-off pressure, FBP: fracture breakdown pressure, ISIP: instantaneous shut-in pressure, and FCP: fracture closure pressure.

In intact rock, the pressure has to overcome not only the minimum horizontal stress, but also the rock tensile strength (T) before a fracture is initiated and fluid leaks into the formation. In this case the leak-off pressure is equal to the formation breakdown pressure (P_b). During a leak-off test, the section of the borehole wall that is pressurized may or may not contain pre-existing fractures, and these, if they are present, are not necessarily normal to the direction of S_{Hmin}. Thus, the leak-off pressure can have a value anywhere between S_{Hmin} and P_b. The relationship between the leak-off pressure and the minimum horizontal stress has been described empirically by some investigators as:

$$P_{lo} = S_{Hmin} + \beta T \qquad (5)$$

where β is a coefficient that varies between 0 and 1 and depends on a variety of factors relating to fluid-rock-fracture interaction (Edwards *et al*., 1998). As rock tensile strengths are generally low (typical values for sandstones and shales are in the range of 300-600 psi [2 to 4 MPa]), the effect of the tensile strength (T) decreases with increasing depth. For this reason, tests performed at shallow depth are less reliable for determining S_{Hmin} because the rock tensile strength plays a more significant role in the fracture onset and the measured pressures will exceed the smallest principal stress by a considerable amount.

Generally, it is preferable to use extended, two-cycle leak-off tests for the local determination of S_{Hmin} (Addis *et al*., 1998; Edwards *et al*., 1998), or at least a complete cycle test. Unfortunately, these tests are very seldom run. In many cases only the leak-off pressure (P_{lo}) is available. Empirical evidence suggests that leak-off pressures are, on average, 6% to11% higher than S_{Hmin} (Breckels and van Eckelen, 1981; Addis *et al*., 1998). In the absence of extended leak-off test data, the use of a lower-bound envelope to a large number of leak-off tests is a simple and apparently reliable estimate of the variation of minimum stress with depth in a sedimentary basin (Addis *et al*., 1998; Edwards *et al*., 1998).

Horizontal stress magnitudes can also be estimated from the fracture breakdown pressures (P_b) recorded during fracture treatments, or the peak pressure reached during a leak-off test (Figure 11) (Bell, 2003; Zoback *et al*., 2003). This represents the pressure at which fracture propagation away from the wellbore occurs, after which pressure drops. For hydraulic fracture tests (micro- or mini-frac, fracture breakdown), pumping continues beyond the point of fracture breakdown for a longer period of time than that represented in Figure 11.

Horizontal stress in "relaxed" sedimentary basins is generated by the weight of the overburden (vertical stress), in which case the ratio between the minimum horizontal and vertical stresses should be constant (Edwards *et al*., 1998). For example, in the southern portion of the North Sea offshore Norway the minimum horizontal stress determined from leak-off tests is in the order of 90% of the overburden stress obtained from density logs (Addis *et al*., 1998; Edwards *et al*., 1998). Lack of a constant ratio between the two as depth increases is an indication of the presence of a stress component other than that generated by the overburden, usually the compressional tectonic stress (σ_T). This "basinal" approach to stress estimation is not applicable in areas with complex geological structures, such as thrust and fold belts, and in the vicinity of salt diapirs.

The maximum horizontal stress (S_{Hmax}) is the most difficult component of the stress tensor to estimate (Zoback *et al*., 2003). It could be determined using the relationship (Haimson and Fairhurst, 1969):

$$P_b = 3S_{Hmin} - S_{Hmax} - P + T \qquad (6)$$

In addition to S_{Hmin} and P, this relation requires knowledge of the breakdown pressure (P_b) and of the rock tensile strength (T) that need independent determination and that are not currently available for the Alberta Basin. Other methods involve the use of borehole breakouts (Zoback *et al*., 2003) or more complex relationships that require additional parameters to be measured. Because the maximum horizontal stress is of secondary importance in the case of the acid-gas injection operations in western Canada, no efforts were made in this study to determine its values.

Unfortunately, in practice, many leak-off tests and fracturing treatments are conducted using poor field procedures and usually poor records are kept. Values of the P_{lo} and P_b that are markedly lower than the expected regional trend should be rejected because, most likely, they indicate a poor quality cement seal or a highly permeable formation rather than an anomalously low value of the minimum horizontal stress (Edwards *et al*., 1998; Zoback *et al*., 2003). Similarly, stress magnitude estimates in hydrocarbon reservoirs that have undergone production are not representative of the original (virgin) stress regime because depletion results in stress changes.

Stress orientations are important because they indicate the most likely direction of fractures and fracture propagation if they occur. The most commonly used information for estimating stress orientations is derived from borehole breakouts (Bell, 2003). These breakouts are intervals in a well where caving has occurred on opposite sides of a wellbore, so that it is laterally elongated, and are diagnostic of anisotropic compression around the borehole (i.e., $S_{Hmin} \neq S_{Hmax}$). In quasi-vertical wells (<5° of vertical) through transversely isotropic rocks, breakout caving elongates the wellbore parallel to S_{Hmin} (Bell, 2003; Zoback *et al*., 2003). Figure 12 shows the relationship between a borehole breakout and the principal stress orientations in a well. Breakouts are best displayed on borehole imaging logs, but logging tools, such as dipmeters, are also suitable for documenting breakouts (Bell, 2003).

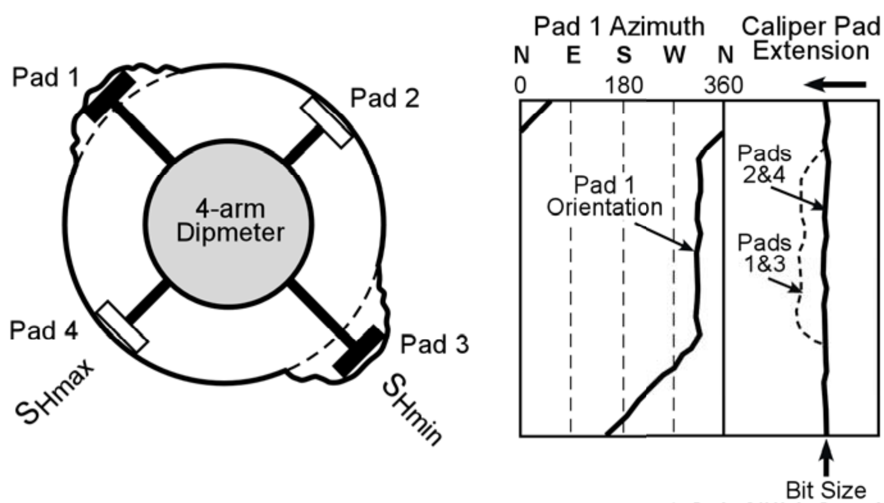


Figure 12. Diagrammatic representation of the relationship between breakouts in a well and stress orientations, including a typical four-arm caliper log signature (after Bell, 2003).

3.2 Data Sources and Processing

Data from various sources were used to determine the stress regime at the acid-gas injection sites in the Alberta Basin. Magnitudes and gradients of the vertical stress S_V were calculated at 1 m intervals for each acid-gas injection site on the basis of density logs. In approximately half of the cases density logs were taken in the injection well itself, although in a few instances the log had to be extrapolated to the injection depth. In the other cases no density log exists for the injection well and logs from nearby wells had to be used. However, because the density of sedimentary rocks varies in a narrow range, the stress magnitude and gradient obtained at a nearby well is certainly representative for the acid-gas injection well.

Minimum horizontal stresses were not estimated at any acid-gas injection site and fracturing pressures were determined or estimated by operators as described in the section 2.3. For this study, data from micro-frac, mini-frac and leak-off tests, and fracture breakdown pressures recorded in hydraulic fracturing in the Alberta Basin were collected and used for the determination of the minimum horizontal stress regime in the basin. The basinal stress regime was used to estimate the local value of S_{Hmin} at each individual site. Table 2 indicates the number of each type of test used in the analysis and the number of different locations (wells) these tests were performed in. Only tests performed at depths greater than 300 m were considered for the reason explained previously, namely that the rock tensile strength plays, proportionally, a more important role at shallow depth than at larger depth, and the leak-off and hydro-frac tests in such cases will be an unreliable indicator of the in situ stress magnitude.

Table 2. Number of tests used in the determination of the magnitude and direction of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

Parameter or Test Type	Initial Number	Retained Number	Number of Wells
Micro-Frac Tests	16	15	8
Mini-Frac Tests	98	91	75
Leak-Off Tests	1,381	757	751
Fracture Breakdown Pressure (Hydro-Frac)	979	586	531
Breakouts for Stress Orientation	252	246	151

In quite a number of cases the location of the test could not be matched with an existing well, most likely due to a recording error by the company that performed the test, and these tests could not be used in the analysis (one micro-frac test, seven mini-frac tests, 40 leak-off tests and 4 hydro-frac tests). Many leak-off and hydro-frac tests have a quality code assigned by the service company that performed the test; however, a significant number had no quality code assigned. All the poor-quality tests were rejected from further analysis, but the ones without a quality code designation were still retained for further screening. Low-quality tests (i.e., where the pressure build-up did not cause leak off) were culled. Tests run in reservoirs with fluid pressure gradients less than 8 kPa/m were rejected, since such low pressure compared with hydrostatic (~10 kPa/m) implies fluid depletion and possible reduction of the virgin stress magnitude. Tests with gradients less than 12 kPa/m were also rejected because they most likely indicate a poor cement-sealing job, loss of fluids in a very permeable formation, or closure pressures recorded in depleted reservoirs. Neither of these cases is representative for the stress regime in the basin. Similarly, tests with anomalously high gradients, greater than 30 kPa/m, were rejected, considering that the lithostatic gradient is ~25 kPa/m. Twenty-nine leak-off tests performed in the thrust and fold belt of the Rocky Mountains were similarly not considered. The results of this culling process are shown in Table 2.

The type and age of the rocks were also considered in the analysis, by splitting the data set by stratigraphic age. Table 3 shows the distribution of the various tests by stratigraphic interval. In assessing the data distributions, one should remember that there is no injection of acid gas in Tertiary and Upper Cretaceous strata, that only in five cases acid gas is injected in Lower Cretaceous strata in central and eastern Alberta, that in the Peace River and northeastern British Columbia acid gas is injected in Carboniferous-to-Triassic strata, and that at all other sites in central and northwestern Alberta acid gas is injected in Devonian strata (Table 3).

Table 3. Stratigraphic distribution of tests used for the determination of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

Stratigraphic Interval	Number of Acid Gas Injection Sites	Micro- and Mini-Frac Tests	Leak-off Tests	Hydro-Frac Tests	Total Number of Tests for S_{Hmin}
Tertiary	-		203		203
Upper Cretaceous	-	40	425	130	595
Lower Cretaceous	5	42	103	163	308
Jurassic	1	2		19	21
Triassic	9	5	6	166	177
Permian	5	3		8	11
Carboniferous	5		3	33	36
Devonian	23	14	17	64	95
Cambrian	-				
Total	48	106	757	583	1,446

Figures 13-16 show the distribution of tests by various stratigraphic intervals and in relation to the location of those sites that inject acid gas in that particular interval. The drop in the number of tests by stratigraphic interval is due to the fact that less wells penetrate deeper intervals and less tests were performed, and also to the fact that, due to erosion, the Carboniferous-Jurassic interval is present only in the western and southern parts of the Alberta Basin, as shown by the data distribution (Figure 15).

As discussed previously, the leak-off pressure (P_{lo}) has values anywhere between the true minimum horizontal stress (S_{Hmin}) and the fracture breakdown pressure because of the tensile strength of the rocks (see equation 5 above). To minimize this effect, in regions with clusters of tests, mainly close to the Rocky Mountain Deformation Front, only the test with the lowest gradient was selected for further mapping. Most of the selected wells contain only one test, although there are a few cases with more than one. Since the fracture pressure profiles are representative only for the tested interval, and not for the

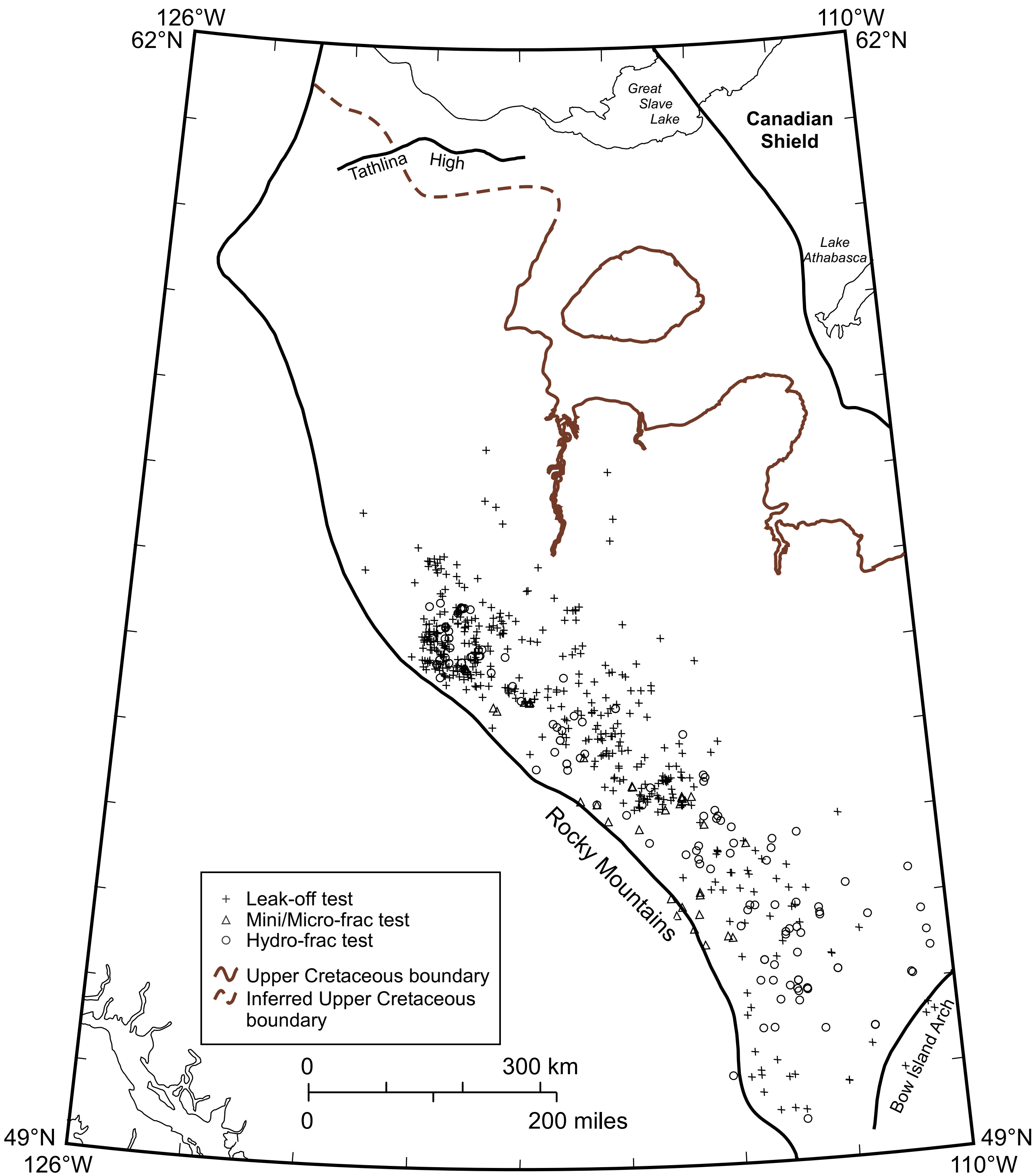


Figure 13. Distribution in Upper Cretaceous - Tertiary strata of tests used for the determination of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

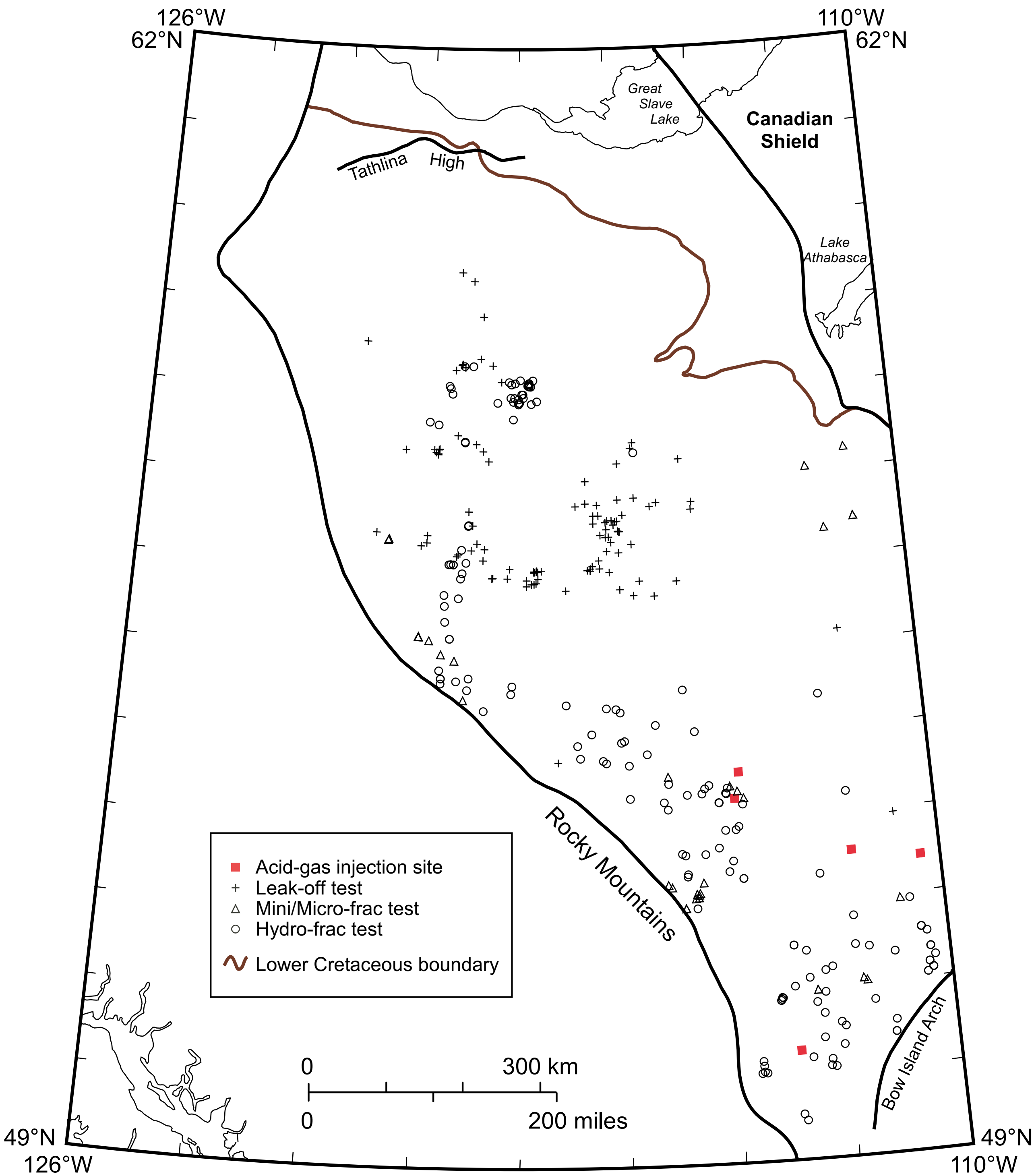


Figure 14. Distribution in Lower Cretaceous strata of tests used for the determination of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

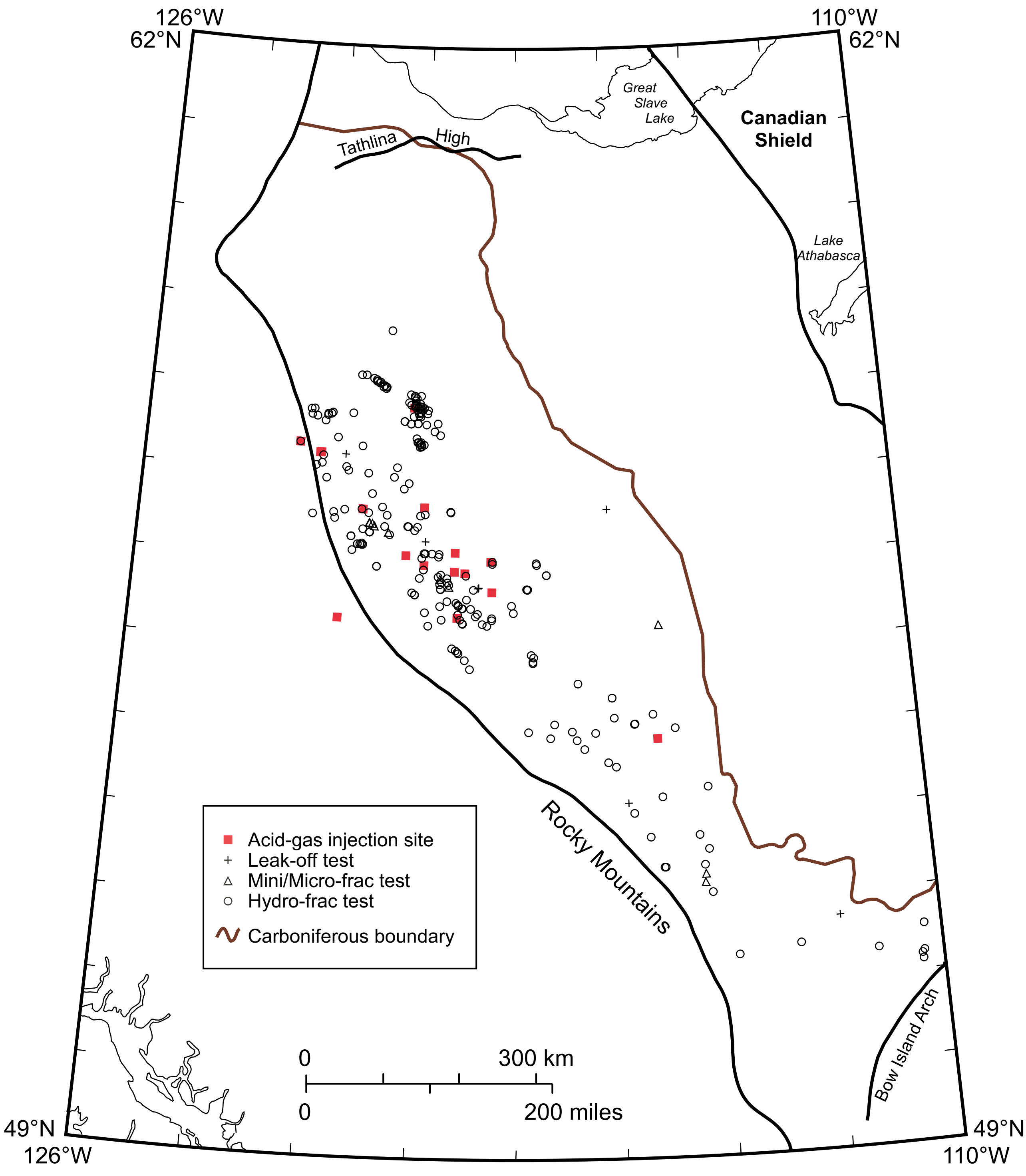


Figure 15. Distribution in Carboniferous - Jurassic strata of tests used for the determination of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

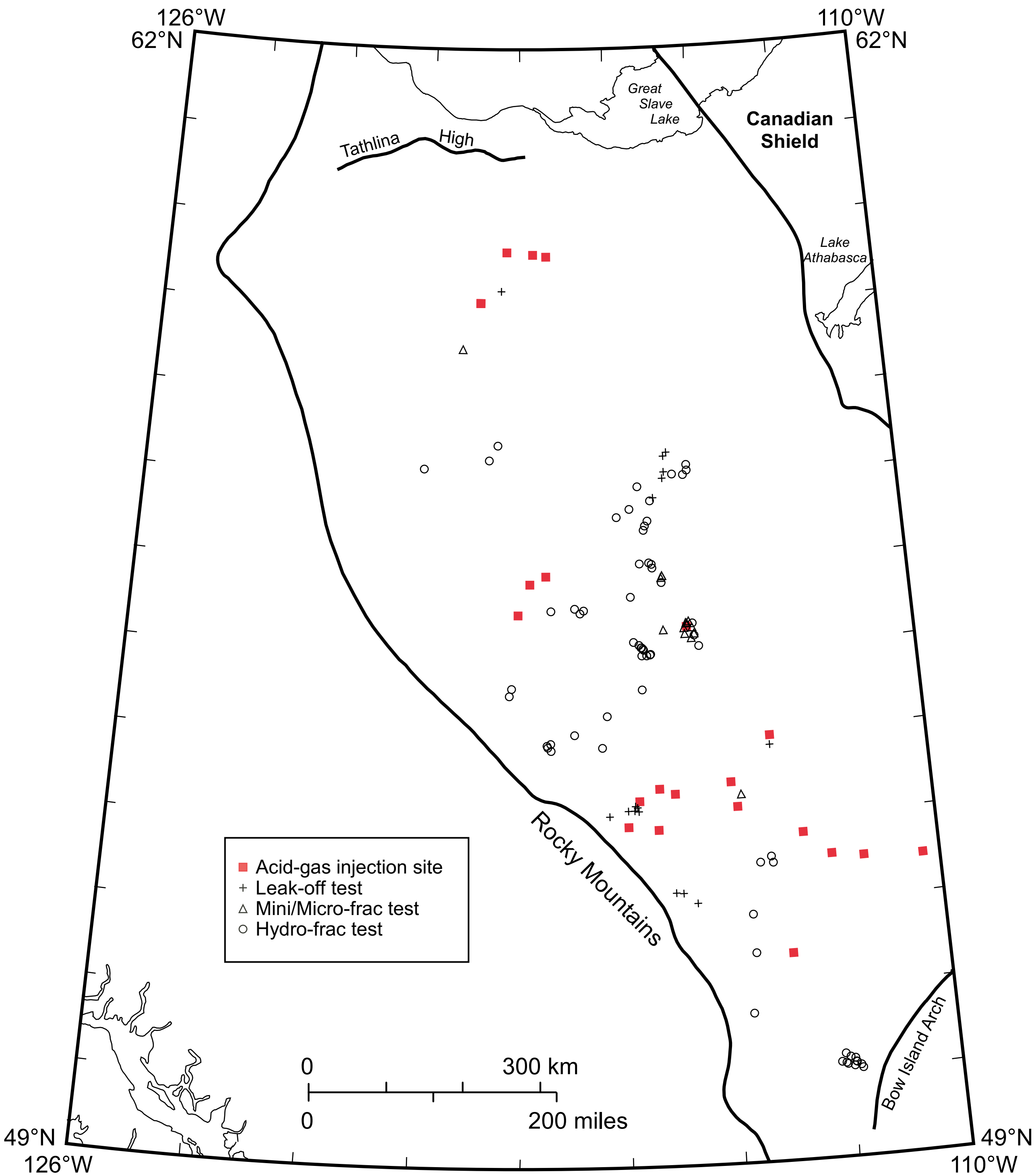


Figure 16. Distribution in Devonian strata of tests used for the determination of the minimum horizontal stress (S_{Hmin}) in the Alberta Basin.

full well length, the "normalized" characteristic that can be transferred to a different location and/or depth is the stress gradient:

$$\nabla S_{H\min} = \frac{S_{H\min}}{D} \tag{7}$$

where D is the test depth.

Similarly with various tests used for the determination of the minimum horizontal stress, no breakouts were identified specifically in the wells used for acid gas injection in the Alberta Basin. Instead, breakouts in wells across the basin (see Table 2) were used to map stress trajectories at the basin level, as previously done for the entire Western Canada Sedimentary Basin and for the coal-bearing Cretaceous – Tertiary strata in southern and central Alberta (Bell *et al*., 1994; Bell and Bachu, 2003). Figure 17 shows the location of wells with breakouts and the mean azimuths of the maximum horizontal stress (S_{Hmax}). Because the minimum horizontal stress (S_{Hmin}) is normal to the maximum horizontal stress, and because, if tensile fractures occur, they will develop in the plane normal to S_{Hmin}, the azimuths of S_{Hmax} shown in Figure 17 represent the most likely direction of fracture propagation. The direction of the maximum horizontal stress (S_{Hmax}) in the Alberta Basin is generally normal to the Rocky Mountain Deformation Front (hence the direction of S_{Hmin} is parallel to it). This indicates that a certain level of tectonic stress (σ_T) caused by orogenic processes, is present in the basin. The directions of the minimum and maximum horizontal stresses at the acid-gas injection sites were obtained using this data set through interpolation or extrapolation.

3.3 Alternative Estimation of the Minimum Horizontal Stress

As discussed previously, the most common method used for estimating the minimum horizontal stress is the use of micro-, mini- and leak-off tests, and fracture treatment pressure records. Another possible method for estimating S_{Hmin} is the use of geomechanical mathematical models. The equations used for the prediction of S_{Hmin} fall into two categories: elastic basin models, which are based on the Poisson's ratio effect, and limit equilibrium models, which are based on the limiting strength of faults in the local area of interest. Within these two categories there are many variations that account for such factors as poro-elastic stress corrections due to injection or depletion, anisotropy of mechanical properties, tectonics, lateral strains in the basin, temperature effects, type of the stress regime (normal, strike slip or thrust fault), and others. The experience of the private sector in Alberta Basin indicates that special attention should be applied in the direct application of a mathematical modeling approach, and that calibration of results with high-quality fracture tests is desirable.

Due to the general lack of data regarding geomechanical properties of the rocks in the Alberta Basin, a simple elastic-basin model has been used to estimate S_{Hmin} in the Pembina-Wabamun area of west-central Alberta, where three operators inject acid gas in the Wabamun Group aquifer. The equation used for predicting the average horizontal stress (S_H) is:

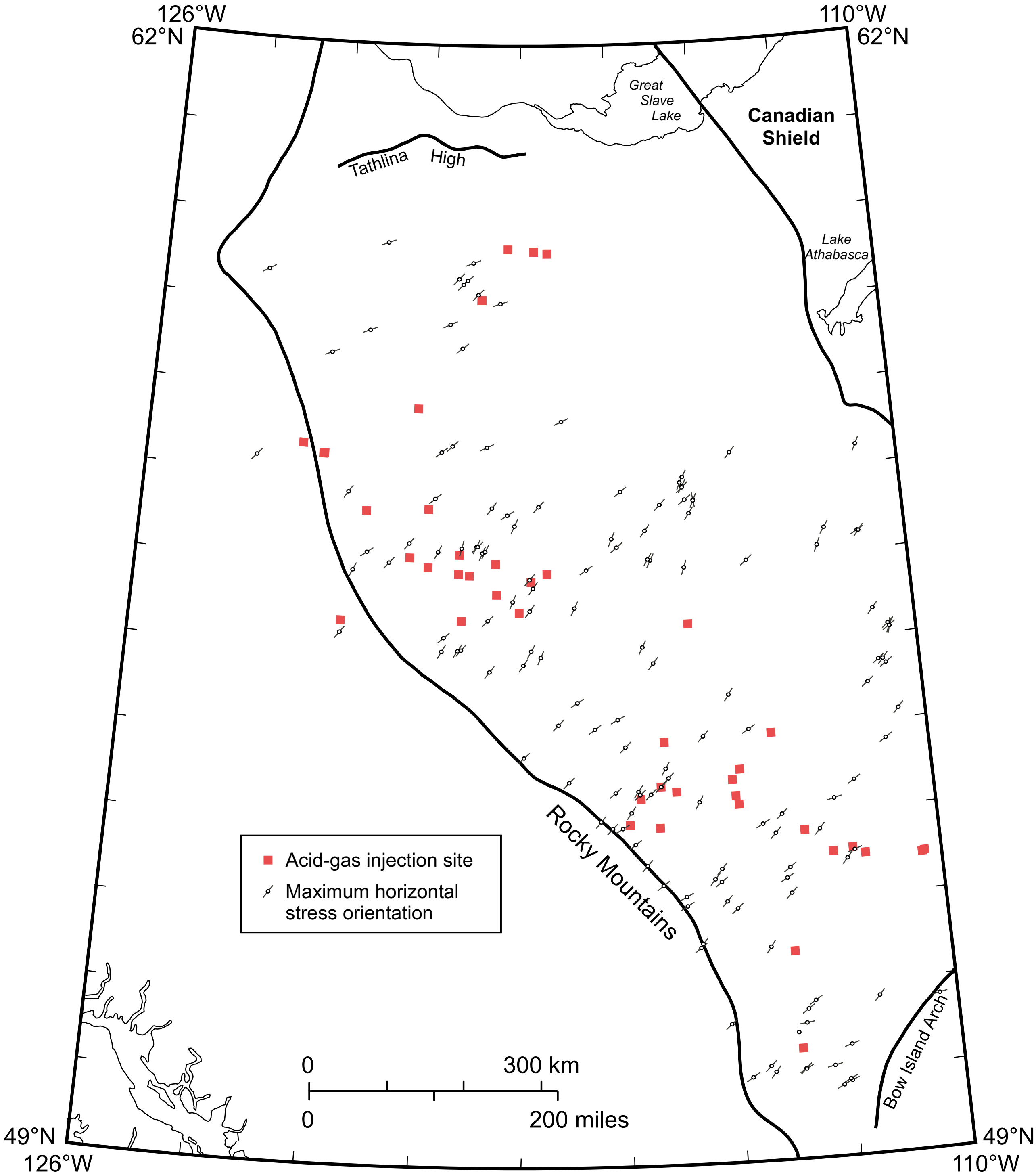


Figure 17. Direction of maximum horizontal stresses, hence most likely of fractures in the Alberta Basin, as estimated from breakouts in wells.

$$S_H = \frac{\nu}{1-\nu}(S_V - \alpha P) + \alpha P + \sigma_T \tag{8}$$

where α is Biot's poro-elastic parameter and the subscript $_H$ denotes horizontal. All other parameters have been defined previously. Note that Eq. (8) does not account for anisotropy of the horizontal stress, and it is common industry practice to use this equation for estimating S_{Hmin}, ignoring any issues of rock property anisotropy or lateral strain differences in the basin, which both would lead to horizontal stress anisotropy (for example, see Eq. (3) which is a simplification of this equation by assuming α = 1 and σ_T=0). This equation applies to initial conditions in a reservoir or aquifer, prior to any pressure changes (ΔP) caused by injection or production. Otherwise, Eq. (8) should include a correction that accounts for changes in pressure:

$$S_H = \frac{\nu}{1-\nu}(S_V - \alpha P) + \alpha P + \sigma_T + \frac{1-2\nu}{1-\nu}\alpha \cdot \Delta P \tag{8'}$$

Even application of this simple model requires knowledge of three parameters: ν, α and σ_T. Biot's poro-elastic parameter (α) is usually assumed to be equal to 1. In the absence of any information, literature values can be used for Poisson's ratio (ν). Commonly used values are in the 0.25 – 0.35 range. The tectonic stress (σ_T) is specific to the area and strata of interest and is the most difficult to evaluate. Application of this model to the Cardium Formation in the Wapiti Field, southwest of Grande Prairie, Alberta, has shown that the predicted profile of horizontal stress did not match the measured data mainly as a result of a strong local component of the tectonic stress (McLellan, 1988), the field being located at a relatively short distance (~60 km) from the Laramide Rocky Mountain Deformation Front in the Alberta Basin. Evidence from mini-frac tests and hydraulic fracture tests in the Alberta Basin suggest that the magnitude of the tectonic component of the horizontal stress decreases with increasing distance from the Rocky Mountain Deformation Front (Bell *et al.*, 1994; Bell and Bachu, 2003). Closer to the Foothills, calibration to micro- and mini-frac tests would be needed to decide if the tectonic stress component should be included.

Assuming the absence of a tectonic stress component in the Pembina area (σ_T =0), the only parameters needed for estimating the horizontal stress with Eq. (6) are formation pressure (P) and Poisson's ratio (ν). As a first approximation, the initial pressure can be assumed to be hydrostatic. Poisson's ratio, as well as other geomechanical properties, can be estimated using full wave sonic logs, according to:

$$\nu_d = \frac{\frac{1}{2}\left(\frac{\Delta t_s}{\Delta t_c}\right)^2 - 1}{\left(\frac{\Delta t_s}{\Delta t_c}\right)^2 - 1} \tag{9}$$

where Δt_s and Δt_c are transit times of shear and compressional wave intervals, respectively, and ν_d is the dynamic Poisson's ratio. Some general values are given in industry for the ratio of shear to compressional transit times, e.g. $(\Delta t_s / \Delta t_c) = 1.842$ for carbonate rocks and $(\Delta t_s / \Delta t_c) = 1.586$ for sandstone rocks, and these values would lead to Poisson's ratios of $\nu_d = 0.29$ for carbonate rocks and $\nu_d = 0.17$ for clastic rocks, respectively (Serra, 1986). However, a search of digital well log data in the EUB's database identified a well with full wave sonic data at 5-2-47-14W5. Using these data, a full wave sonic log analysis procedure was applied to process, filter and analyze the data for dynamic elastic properties of the rocks in the Wabamun Group into which acid gas is injected in the Pembina area.

Application of Eq. (8) for estimating the minimum horizontal stress requires the "static" rather than the "dynamic" Poisson's ratio, and usually there is a difference between the two in many rocks. However, this difference is usually small as the rock porosity drops below 10%, which is the case of Wabamun Group strata. Given other uncertainties introduced by data and methodology, and for the purpose of this exercise, it is safe to assume that the static and dynamic Poisson's ratios are equal. The vertical stress (σ_V) in Eq. (8) was estimated by integrating the bulk density log in the same well according to Eq. (4). Based on the bulk density and full sonic logs in this well, Poisson's ratio varies in the Wabamun Group (from 3,432 to 3,648 m depth) between 0.11 and 0.37, with a mean of 0.31 and standard deviation of 0.03. Note that the mean value of $\nu = 0.31$ is close to the value of $\nu = 0.29$ used by industry for carbonate rocks in absence of any information.

Figure 18 shows a plot of calculated S_{Hmin} depth profiles in the Wabamun Group in the Pembina area for values of Poisson's ratio of $\nu = 0.3$ and $\nu = 0.35$. Also plotted are the hydrostatic pore pressure (P) and the vertical stress (S_V), which were calculated with standard gradients of 9.81 kPa/m and 23.6 kPa/m, respectively, and were used in Eq. (8). The S_{Hmin} values estimated on the basis of fracture tests (see the previous section) at the top and bottom of the Wabamun Group at the four acid-gas injection sites in the Pembina area are also shown. The results of this calculation validate the use of fracture tests for estimating minimum horizontal stresses in the Alberta Basin. On the other hand, application of this method at each acid-gas injection site requires detailed information about initial pressures, changes in pressure due to production and/or injection, and knowledge of Biot's elastic parameter (α), (assumed to be equal to 1 in this exercise), tectonic stress (σ_T), (assumed negligible here), and Poisson's ratio (ν) from lab determinations or sonic logs. Since this information is not available for most, if not all of the acid-gas injection sites, and the effort to obtain it, if possible at all, is well beyond the scope of this study, stresses at the acid-gas injection sites in the Alberta Basin were estimated on the basis of fracture tests.

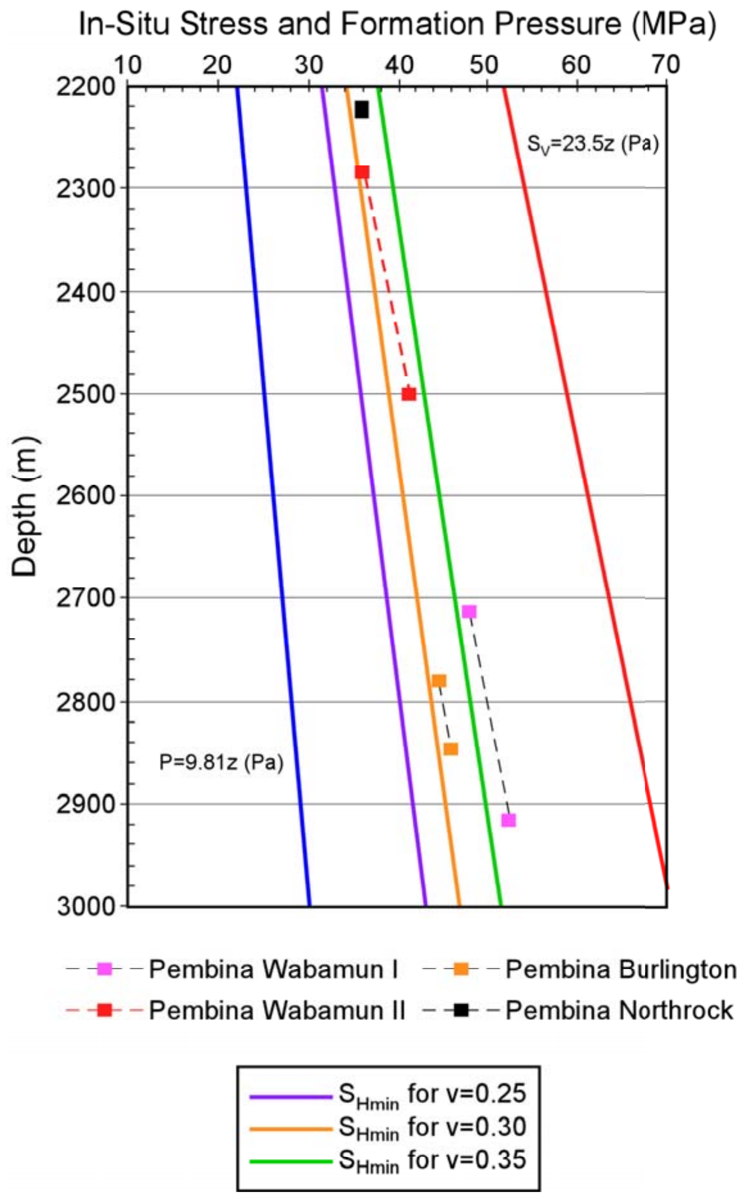


Figure 18. Depth profiles of the predicted minimum horizontal stress in the Wabamun Group in the Pembina area from log-derived rock properties. Stress estimates at the top and bottom of the Wabamun Group at the four acid-gas injection sites in the Pembina area are also shown. The estimates are based on fracture tests at wells in the area.

4 Stresses at Acid-Gas Injection Sites

4.1 Minimum and Maximum Stress

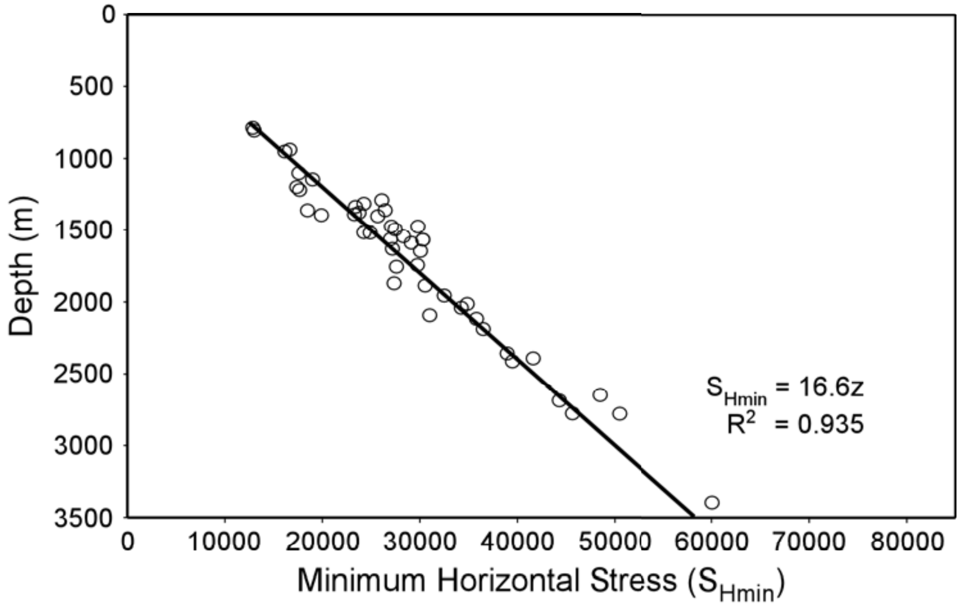
Stresses and their direction at the acid-gas injection sites were estimated using the methodology described in section 3.1 using the data presented in section 3.2 (Table 4). Stresses were estimated at the top of the injection unit, on the reasoning that upward leakage should be avoided/prevented. Table 4 shows the estimated vertical and minimum horizontal stresses, and direction of the maximum horizontal stress (fracture direction) at the acid-gas injection sites. Figure 19 shows the variation with depth of the minimum horizontal stress (S_{Hmin}) and of the vertical stress (S_V), respectively, at the sites. The vertical stress is actually the maximum stress, and the minimum horizontal stress is the minimum stress of the stress tensor, with the maximum horizontal stress (S_{Hmax}) having a value between these two.

Table 4. Estimated vertical and minimum horizontal stresses, and direction of the maximum horizontal stress (fracture direction) at the acid-gas injection sites in western Canada.

Injection Site	Depth to Unit Top (m)	Vertical Stress (S_V) (MPa)	Gradient of Vertical Stress (kPa/m)	Minimum Horizontal Stress (S_{Hmin}) (MPa)	Gradient of Minimum Horizontal Stress (kPa/m)	Orientation
Acheson	1182	25.2	21.3	16.3	13.8	56
Bellshill Lake	913	19.4	21.2	13.9	15.2	41
Bistcho	1601	38.5	24.0	28.3	17.7	45
Boundary Lake South	1661	38.1	22.9	26.7	16.1	45
Brazeau	3386	79.1	23.4	58.9	17.4	51
Bubbles	1297	32.7	25.2	25.3	19.5	48
Dizzy	1110	27.1	24.4	16.5	14.9	37
Dunvegan	1355	31.6	23.3	22.8	16.8	22
Eaglesham North	1927	46.5	24.1	31.0	16.1	23
Galahad	1200	27.3	22.8	16.6	13.8	51
Golden Spike	1957	46.1	23.6	28.2	14.4	40
Gordondale Belloy	1905	46.4	24.4	29.9	15.7	22
Gordondale Halfway	1552	37.3	24.0	24.5	15.8	22
Hansman Lake	809	17.2	21.2	12.3	15.2	52
Kelsey	1167	26.2	22.5	18.4	15.8	45
Long Coulee	1430	32.9	23.0	24.2	16.9	41
Marlowe	1373	32.1	23.4	22.5	16.4	42
Mirage	1391	33.3	23.9	26.0	18.7	22

Mitsue	705	15.2	21.6	10.6	15.0	29
Mulligan	1589	36.3	22.8	26.5	16.7	22
Norcen Caribou Debolt	2086	52.0	25.0	35.7	17.1	51
Norcen Caribou Halfway	1652	41.0	24.8	28.9	17.5	51
Normandville	1745	40.9	23.4	26.2	15.0	23
Paddle River	1541	35.9	23.3	23.7	15.4	45
Parkland	2443	59.4	24.3	39.1	16.0	31
PC Jedney	1487	37.4	25.2	29.0	19.5	48
Pembina Burlington	2781	67.4	24.2	44.6	16.0	42
Pembina Wabamun-I	2715	61.4	22.6	47.9	17.6	42
Pembina Wabamun-II	2285	51.5	22.5	36.0	15.8	42
Pembina Northrock	2222	53.4	24.0	36.1	16.2	42
Pouce Coupe	2036	50.2	24.7	33.7	16.6	22
Provost Keg River	1416	32.4	22.9	22.8	16.1	52
Provost Leduc	1341	28.8	21.5	17.4	13.0	50
Puskwaskua	2677	64.4	24.1	48.0	17.9	22
Redwater	945	22.5	23.8	15.8	16.7	52
Ring	950	22.7	23.9	15.2	16.0	48
Rycroft	1760	41.9	23.8	29.1	16.5	26
Strathfield	1422	31.4	22.1	19.7	13.9	55
Sukunka	2633	65.8	25.0	42.5	16.1	33
W. Stoddart I	1590	37.8	23.8	29.7	18.7	30
W. Stoddart II	1590	37.6	23.6	29.7	18.6	30
Watelet	2010	47.9	23.8	33.5	16.7	56
Wayne-Rosedale	1880	41.8	22.2	26.6	14.1	60
Wembley	2407	60.1	25.0	40.9	17.0	40
Zama X2X	1478	36.5	24.7	26.2	17.2	45
Zama Z3Z	1493	36.7	24.6	26.4	17.2	45
Zama Slave Point	1317	31.9	24.2	23.3	17.2	45
Zama Keg River	1531	37.7	24.6	27.1	17.2	45

a.



b.

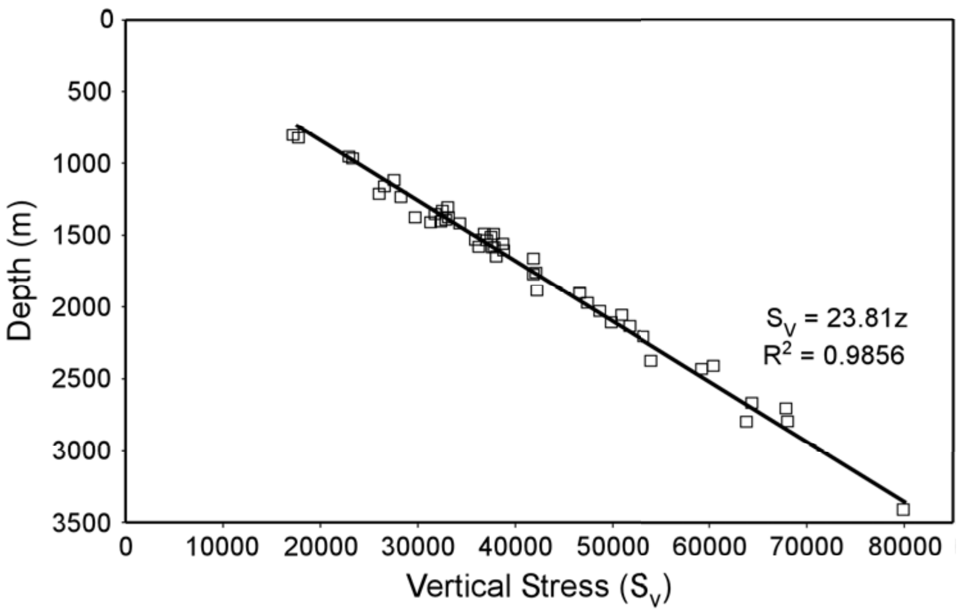


Figure 19. Variation with depth of stresses at acid-gas injection sites in western Canada: a) minimum horizontal stress (*S_{Hmin}*) and b) vertical stress (*S_V*).

Minimum horizontal stresses, varying between 10.6 MPa at 705 m depth at Mitsue and 58.9 MPa at 3386 m depth at Brazeau, increase with depth with a basin-wide average gradient of 16.6 kPa/m (R^2=0.935; Figure 19a), although locally stress gradients vary between 13.6 and 19.5 kPa/m (Table 4). Maximum vertical stresses vary between 15.2 MPa at 705 m depth at Mitsue and 79.1 MPa at 3386 m depth at Brazeau, with local vertical stress gradients that vary between 21.6 and 23.4 kPa/m (Table 4). Vertical stresses increase with depth with a basin-wide gradient of 23.8 kPa/m (R^2=0.986; Figure 19b). On a basin wide scale, minimum horizontal stresses are 70% of the vertical stress, confirming general literature relationships between the two.

Minimum horizontal stresses (S_{Hmin}) are in all but one case greater than the maximum bottom hole pressure (BHIP) (Figure 20a). Only at the Mirage site, rescinded in June 1999, the minimum horizontal stress S_{Hmin}, as determined in this study, is less than the maximum BHIP. However, given the low accuracy of these estimates, it is more likely that in reality S_{Hmin} is greater than the maximum BHIP. In addition, acid gas was injected at Mirage with injection water for a waterflood scheme in an oil pool under secondary oil recovery. The waterflood scheme was designed with bottom hole pressure monitoring to maintain reservoir pressure at 9,500 kPa, which was about 3,500 kPa below the initial pool pressure. Thus, the bottom hole pressure was maintained at all times below the initial reservoir pressure, hence less than S_{Hmin} and P_f, whatever are their true values. At no time was there any danger of opening existing fractures, if any are present, as a result of injection. This operation was rescinded when the gas plant was shut down and the gas was rerouted to another gas plant.

In all cases minimum horizontal stresses (S_{Hmin}) are less than the fracturing pressure (P_f) (Figure 20b), on average by 12.3% (Figures 5 and 20b), although they vary from as low as 58% to as high as 98% of P_f. The wide variability in the ratio between P_f and S_{Hmin} is due to the fact that in most cases both are estimated rather than measured. Also, the fact that in several cases S_{Hmin} is very close to P_f is due to the fact that, unless P_f is measured, the operators prefer to be conservative and underestimate the fracturing pressure (P_f) in their calculations, thus ensuring safety of the operations.

The results so far confirm that:

- Maximum bottom hole injection pressures (BHIP) as set for the acid-gas injection operations in western Canada are safely below the minimum horizontal stress (S_{Hmin}); thus, if this pressure is reached, there is no danger of opening pre-existing fractures, if any exist.
- Minimum horizontal stresses (S_{Hmin}) are lower by 12.3% on average than rock-fracturing pressures (P_f) thus there is no danger of inducing new fractures.
- Minimum horizontal stresses (S_{Hmin}) are 30% less on average than the vertical stress (S_V) showing that fractures in the Alberta Basin are vertical, except in the shallow zones (a few hundred meters deep) in the northeast.
- The orientation of fractures would be perpendicular to the Rocky Mountain Deformation Front, varying between ~22 and 60 degrees North.

a.

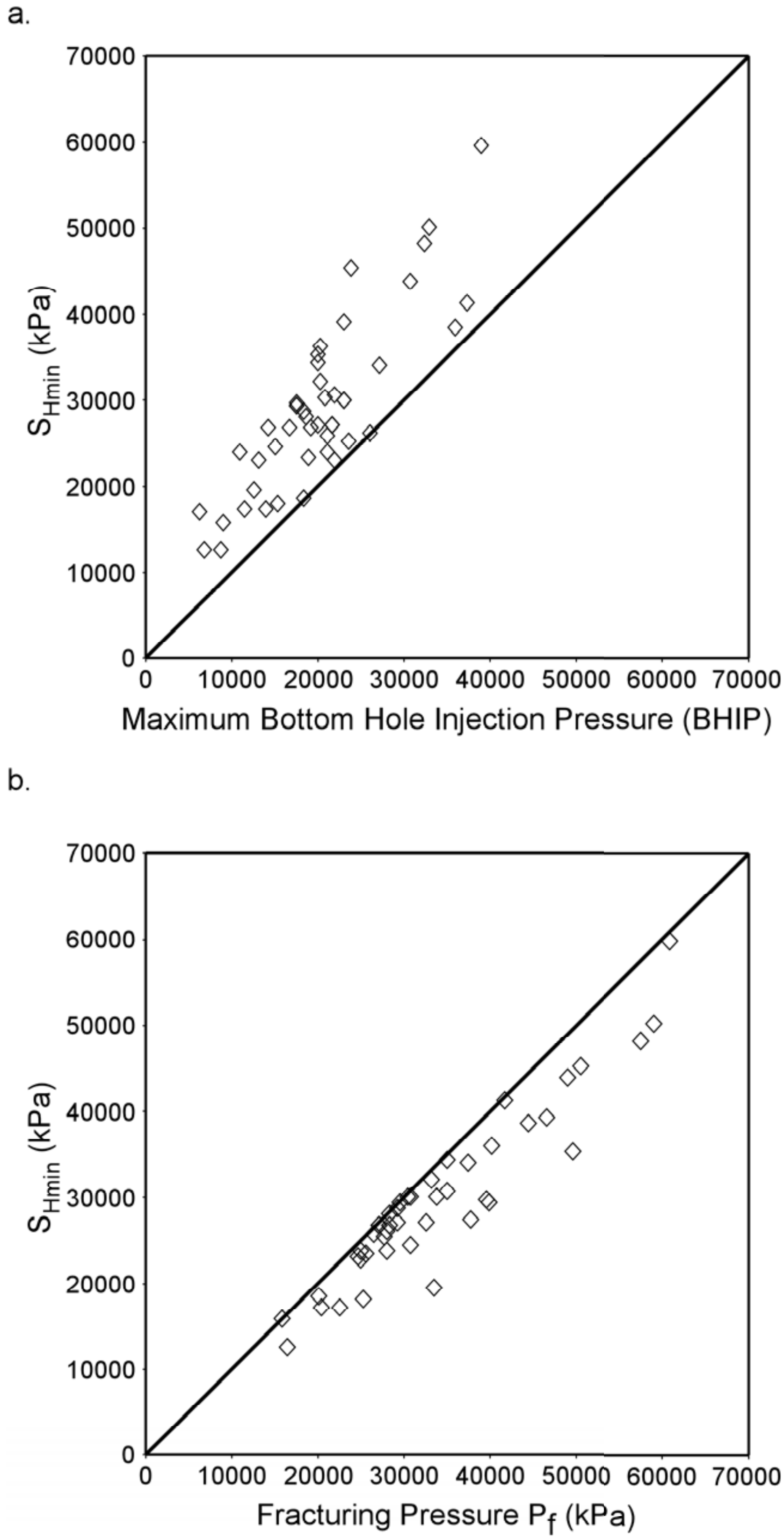


Figure 20. Relation between the minimum horizontal stress (*S_{Hmin}*) and: a) maximum bottom hole injection pressure (BHIP), and b) fracturing pressure (*P_f*) at acid-gas injection sites in western Canada.

However, the wide range of variability in the ratio between minimum horizontal stresses (S_{Hmin}) and fracturing pressures (P_f) points out to the need to perform hydraulic tests at each site, rather than estimate P_f from basin-wide fracturing gradients or numerical models. Performing carefully conducted tests will also allow site-specific determination of the minimum horizontal stress (S_{Hmin}). Determination of the minimum horizontal stress (S_{Hmin}) is also important in setting the maximum bottom hole injection pressure (BHIP) to ensure that pre-existing fractures, if present, will not be opened as a result of injection.

4.2 Maximum Wellhead Pressure for Acid Gas Injection

At the three sites sour water is injected, Bellshill Lake, Mitsue and Redwater, the injected fluid is almost incompressible and of approximately constant density, such that Eq. (2) applies in calculating the bottom hole injection pressure (BHIP), or, vice versa, the wellhead injection pressure (WHIP). In such cases, unless hydraulic tests are performed to determine the minimum horizontal stress (S_{Hmin}) and the fracturing pressure (P_f) the wellhead injection pressure (WHIP) should be established according to Table 1. Although no such tests were performed at the three sites, a simple verification shows that the maximum bottom hole injection pressure (BHIP) for these sites is below the estimated minimum horizontal stress (S_{Hmin}) and, consequently, less than the fracturing pressure (P_f). Actually at two sites, Mitsue and Redwater, because the pressure in the injection unit is subhydrostatic, there is no need for any pressure at the wellhead (WHIP=0). The sour water flowing down well and entering the formation is driven by gravity only.

For all other sites, because the acid gas is highly compressible and of extremely variable density, the hydrostatic weight of the acid gas column in the well is not sufficient to overcome the pressure in the injection unit when added to a wellhead pressure established according to Table 1. To verify this condition, the hydrostatic weight of the acid gas column was estimated and added to maximum wellhead injection pressures prescribed according to Table 1. Because establishing the true bottom hole pressure and temperature, hence gas density, is very complex (see Section 2.2), an upper-limit, overestimating case is considered here. The process is described in the following:

1. A hypothetical wellhead density of the injected acid gas for each site was calculated on the basis of multi-annual averages of gas composition and wellhead temperature (Bachu *et al*., 2004) for wellhead pressures prescribed according to Table 1. Corresponding average gas density at the wellhead varies between 84 kg/m^3 for injection with WHIP = 4300 kPa (corresponding to 1400 m depth), and 862 kg/m^3 for injection with WHIP = 13,728 kPa (corresponding to injection at 3,386 m depth). These would be the density of the acid gas at the sites if the maximum wellhead injection pressure would be established according to Table 1 (from EUB Guide 51).
2. A hypothetical bottom hole density of the injected acid gas was calculated on the basis of multi-annual gas composition and formation temperature (Bachu *et al*., 2004) and a pressure that corresponds to the bottom hole pressure generated by a column of water (gradient of ~10kPa/m) rather than acid gas in the well (i.e., using Eq. (2) for injecting water rather than Eq. (1) for acid gas). Because the hydrostatic weight of a water column is greater than the weight of an acid gas column of the same length, these pressures are overestimations, hence the density of the acid gas calculated for

these pressures is higher than the density that the gas will normally have in a column of acid gas. Density values calculated with this procedure vary between 533 and 808 kg/m^3. In both cases (at the wellhead and bottom hole), acid gas density was calculated based on Bachu and Carroll (2004). The seeming contradiction that the maximum density at bottom hole conditions is less than the maximum density at wellhead conditions is due to the greater effect on density of higher temperature at depth than the corresponding effect of higher pressure (Bachu, 2004).

3. Although the density of acid gas in a well does not vary linearly, an average density was assumed, equal to the arithmetic average of the wellhead and bottom hole densities. Calculated average densities vary between 312 and 804 kg/m^3.
4. Because using water density (1000 kg/m^3) clearly overestimates the bottom hole pressure produced by a column of acid gas (average density <800 kg/m^3) by 25% to >300%, steps 2 and 3 were repeated with a bottom hole pressure that was recalculated using a gradient reduced first by 20% and then iteratively down to 7.5 kPa/m. The new well density averages range from 439 to 743 kg/m^3.
5. A hypothetical maximum bottom hole injection pressure ($BHIP_h$) was calculated using Eq. (2) with the maximum wellhead injection pressures prescribed according to Table 1, constant acid gas density calculated according to the preceding steps, and neglecting friction losses. Obviously this maximum bottom hole injection pressure is an overestimation because, notwithstanding neglect of friction losses, the bottom hole acid gas density was overestimated (see step 2 above).
6. These maximum bottom hole injection pressure values were compared with the corresponding initial formation pressures (P_i). Figure 21 shows a comparison of these hypothetical maximum bottom hole injection pressures ($BHIP_h$) and initial formation pressures. In the majority of cases this hypothetical bottom hole injection pressure ($BHIP_h$) is less than the initial formation pressure (P_i).

This exercise clearly shows that, in the case of acid gas injection (or any other gas for that matter, including CO_2), prescribing the maximum wellhead injection pressure (WHIP) according to Table 1 is not sufficient because the gas most likely will not have enough bottom hole pressure to overcome the formation pressure and enter the injection unit. Only in the case of depleted oil or gas reservoirs it is likely that, in early stages, the bottom hole injection pressure established according to Table 1 would be sufficient to push the gas into the reservoir. However, as the reservoir pressure builds up, at some moment injectivity will become null. An increased wellhead pressure is needed to compensate for the fact that the acid gas is lighter than water. Thus, clearly for acid and greenhouse gas injection in hydrocarbon reservoirs and deep saline aquifers there is need to establish the maximum bottom hole and wellhead injection pressures on the basis of minimum horizontal stress to avoid opening of potential pre-existing fractures, and on the basis of gas properties at reservoir and wellhead conditions (pressure and temperature). The process is iterative because of gas compressibility.

In the absence of tests for determining the minimum horizontal stress and the fracturing pressure, the maximum wellhead injection pressure can be back-calculated indirectly using the values provided in Table 1. Namely, the maximum bottom hole injection pressure can be calculated for the prescribed maximum wellhead injection pressure for the given depth and considering the weight of a water column (step 2 in the procedure described above). Wellhead and bottom hole acid gas density can be estimated for these pressures and given wellhead and formation temperatures. Using an average acid gas density and neglecting friction losses, a new wellhead injection pressure can be calculated on the basis of the maximum bottom hole injection pressure and the weight of the acid gas column. Thus, a new maximum wellhead injection pressure can be estimated. Because of the compressible nature of the gas, the process should be repeated until the difference between values obtained in successive iterations is acceptable.

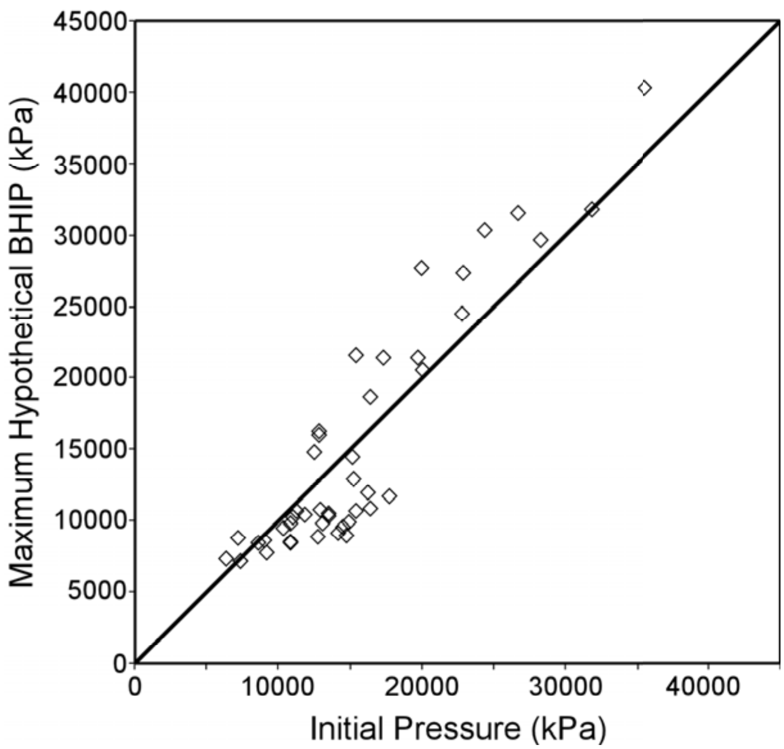


Figure 21. Comparison of the hypothetical maximum bottom hole injection pressures ($BHIP_h$) calculated with maximum WHIP from EUB Guide 51 (EUB, 1994).

5 CONCLUSIONS

Acid gas, a mixture of CO_2 and H_2S that is produced from sour gas reservoirs in western Canada, has been injected into deep geological formations for close to 15 years with a good safety record. Injection currently takes place at 41 locations into depleted oil and gas reservoirs, and deep saline aquifers. Although the purpose of acid gas injection is to dispose of H_2S, large quantities of CO_2 are injected at the same time because it is uneconomic to separate the two gases. To date, close to 5 Mt of acid gas have been injected at current annual rates of ~1 Mt/year. The success of these acid-gas injection operations indicates that the engineering technology for CO_2 geological storage is in a mature stage and ready for large-scale deployment. Major issues that need addressing are the long-term containment of the injected gases in the subsurface and the safety of large-scale operations. From this point of view, the acid-gas injection operations in western Canada constitute a commercial-scale analogue for CO_2 geological storage.

One of the major issues in geological disposal and/or storage of fluids is the integrity of the injection unit (reservoir or aquifer). Maintaining the integrity of the injection formation and of the confining unit is essential in any geological disposal operation of liquid and hazardous wastes to prevent leakage through natural or induced fractures. In this respect, the regulatory agencies in western Canada impose safe limits on the injection pressure in order to maintain the pressure around the injection well below the fracturing threshold of the rocks. An evaluation of the stress regime at the acid-gas injection sites in western Canada was performed to assess the relationship between the maximum allowed wellhead injection pressures (WHIP) and the rock fracturing thresholds.

Determination of the maximum wellhead injection pressure for gases, including acid gas, is complex because of their compressible nature. The maximum bottom hole injection pressure (BHIP), which is the sum of the wellhead injection pressure (WHIP) and of the weight of the column of acid gas in the well (minus friction losses), must be at all times less than 90% of the rock fracturing threshold. Actually, it should be less than the minimum horizontal stress in order to avoid opening of pre-existing fractures. Lately, in the case of injection into depleted reservoirs, regulatory agencies in western Canada are limiting the maximum BHIP to the initial reservoir pressure. The maximum WHIP is then established on the basis of the maximum BHIP and of the column of acid gas in the well. For the acid-gas injection operations, the maximum WHIP has been established at each site on the basis of equipment potential (or limitations) and the maximum BHIP, but in all cases it is greater than the maximum WHIP that would have been set for water injection because of gas compressibility and lower density than water. Higher WHIP is needed to compensate for lower weight of the column of acid gas in the well compared to water.

The stress regime in the Alberta Basin (practically that portion in western Canada where acid gas injection takes place) has been established in this study on the basis of 1446 hydraulic tests (micro-, mini- and hydro-frac tests, and leak-off tests) and on density logs in selected wells. On this basis, the minimum horizontal stress (S_{Hmin}) and vertical stress (S_V) have been estimated at all acid-gas injection sites. Minimum horizontal stresses increase with depth with a basin-wide average gradient of 16.6 kPa/m, with local values that vary between 13.6 and 19.5 kPa/m. Maximum vertical stresses increase with depth with a basin-wide gradient of 23.8 kPa/m, with local vertical stress gradients that vary between 21.2 and 25.2 kPa/m. Fracture pressures (P_f), as estimated by operators, increase with depth with an average gradient of 19 kPa/m, and are at all the sites greater than the minimum horizontal stress, but smaller than the vertical stress. Furthermore, maximum BHIP are safely below the minimum horizontal stress, hence lower than the fracture pressure. Thus, even if the maximum bottom hole injection pressure is attained, there is no danger of opening existing fractures, neither, obviously, of inducing new ones. The orientation of the maximum horizontal stress (S_{Hmax}), hence of fractures, in the basin is generally perpendicular to the Rocky Mountain Deformation Front, as a result of tectonic compression generated by mountain-forming processes.

Furthermore, the study has shown that, in the case of acid or greenhouse gas injection, prescribing the maximum wellhead injection pressure (WHIP) according to general values established for water disposal is not sufficient because the gas most likely will not have enough bottom hole pressure to overcome the formation pressure and enter the injection unit. Thus, for acid and greenhouse gas injection in hydrocarbon reservoirs and deep saline aquifers there is need to establish the maximum bottom hole and wellhead injection pressures on the basis of minimum horizontal stress, to avoid opening of potential pre-existing fractures, and on the basis of gas properties at reservoir and wellhead conditions (pressure and temperature).

The current acid-gas injection operations in western Canada meet the safety criteria imposed by the need to maintain the integrity of the injection unit. However, the wide range of variability in the ratio between minimum horizontal stresses (S_{Hmin}) and fracturing pressures (P_f) points out to the need to perform hydraulic tests at each site, rather than estimate P_f from basin-wide fracturing gradients or numerical models. Performing carefully conducted tests will also allow site-specific determination of the minimum horizontal stress (S_{Hmin}), hence of a better upper limit for the bottom hole injection pressure, to ensure that pre-existing fractures, if present, will not be opened.

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