OVERVIEW OF ACID-GAS INJECTION OPERATIONS IN WESTERN CANADA

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ABSTRACT

Over 2.5 Mt CO₂ and 2.0 Mt H₂S have been injected into deep saline aquifers and depleted hydrocarbon reservoirs at 48 sites in western Canada by the end of 2003, driven by the need to dispose of H₂S produced with natural gas from sour gas reservoirs. Injection of acid gas (CO₂ and H₂S) occurs over a wide range of aquifer and reservoir characteristics, acid gas compositions, and operating conditions. These acid-gas injection operations are a commercial scale analogue to CO₂ geological storage and are representative of aquifers and reservoirs in continental sedimentary basins that have undergone compaction and erosion, like those between the Rocky Mountains and the Appalachians in North America, where CO₂ injection and geological storage on a large scale is most likely to be implemented in Canada and the United States.

INTRODUCTION

Since 1990, faced with the challenge of reducing atmospheric emissions of hydrogen sulphide (H₂S) produced from “sour” hydrocarbon pools, oil and gas producers in the Alberta Basin in western Canada have been turning to disposal of acid gas (H₂S and CO₂, with minor traces of hydrocarbons) by injection into deep geological formations. To date, 48 applications for injection of acid gas produced at 42 different gas plants have been approved in western Canada, of which 41 were active at the end of 2003 (Figure 1). Most operations inject acid gas at a single site (single well), but a few inject or have injected at several sites, such that in total there are 48 injection sites for 42 operations. One operation was not implemented and two were rescinded after a period of operation, either because injection volumes reached the approved limit, or because the gas plant producing the acid gas was decommissioned. At a third operation the site was rescinded because the injection volume reached the limit of the injection reservoir, and it was replaced with injection into a deeper saline formation. At another operation, three different sites have been successively suspended by the regulatory agency because of reservoir overpressuring, with injection currently occurring into a deep saline formation.

Figure 1: Location and status at the end of 2003 of acid-gas injection operations in western Canada.

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At three operations the acid gas is dissolved in water prior to injection, and the resulting weak acidic solution ("sour water") is injected. At seven other sites, of which three have been rescinded, wet acid gas (i.e. acid gas with free water present) is injected. Dry acid gas (i.e. with no free water present) is injected at all other sites. Except for the cases of injection in solution, the acid gas is injected as a dense fluid (liquid or supercritical). The cumulative injection rate for all acid gas injection sites in western Canada reached more than 1 Mt/yr in 2003, of which approximately 480 kt is CO$_2$ (Figure 2a). The cumulative volume of acid gas injected to the end of 2003 reached more than 4.5 Mt, of which slightly more than half is CO$_2$ (Figure 2b).

These acid-gas injection operations represent a commercial-scale analogue to geological storage of CO$_2$. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e. design, materials, leakage prevention and safety) can be adopted for large-scale operations for CO$_2$ geological storage. The characteristics of these operations provide a wealth of information that can be used for the screening and identification of future sites for geological sequestration and storage of CO$_2$. With the advent of emission trading, acid gas injection could become even more appealing to oil and gas producers [1].

Applications for acid gas disposal need to conform to the specific requirements that deal with applications for conventional oil and gas reservoirs [e.g. 2]. 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 or 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 [3, 4]. The specific location is based on a general assessment of the regional geology and hydrogeology, which is designed to evaluate the potential for leakage. Knowledge of the geological setting and characteristics is critical to assess the integrity of the host formation or reservoir, and the short- and long-term fate of the injected acid gas. Of particular importance are potential migration pathways within the injection zone (the spread of the injected acid gas plumes in aquifers is considered in detail in a companion paper [5]) and from the injection zone to other formations, shallow groundwater and/or the surface. To avoid leakage through the caprock or through induced fractures, the maximum bottomhole injection pressure is set by regulatory agencies at 90% of the fracturing pressure in the injection zone. More recently, regulatory agencies are limiting the bottom hole injection pressure in the case of injection into depleted hydrocarbon reservoirs to the initial reservoir pressure or even less.

Regulatory agencies license only the maximum H$_2$S content of the injected acid gas, which varies between 5% and 97% mole fraction. The rest comprises mostly CO$_2$, with a few percent C+ gases for the balance. The actual average composition of the injected acid gas varies from 83% H$_2$S and 14% CO$_2$ to 2%H$_2$S and 95% CO$_2$. The maximum approved wellhead injection pressure varies between 3,750 and 19,000 kPa. Approved daily injection rates vary between 2,000 and 900,000 m$^3$/day. Maximum allowed injection volumes vary between 6x10$^6$ and
Based on the estimated total injection volume and aquifer or reservoir capacity, the acid gas injection sites are planned to operate for periods of 10 to 25 years. For some specific case histories, see [6].

**FACILITIES**

After separation of any gas liquids, the produced sour gas is passed through a contactor or absorber tower in a one- or two-stage process where the sour gas typically comes in contact with an amine or amine derivative solution. The water-saturated acid-gas stream leaves the regeneration unit at 35 to 70 kPa and must be cooled, then compressed for deep injection. After the acid gas is separated, it is compressed, dehydrated, pipelined and injected through a disposal well (Figure 3). These operations depend on the properties of the H$_2$S and CO$_2$ mixture, the two gases having similar phase equilibria [7, 8, 9]. 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$_2$S. The phase behaviour of the acid gas system is represented by a continuous series of two-phase envelopes separating the liquid and gas phases (e.g. Figure 3). Both CO$_2$ and H$_2$S form hydrates at temperatures up to 10°C for CO$_2$ and more than 30°C for H$_2$S, even if free water is not present [7, 9, 10], thus it is desirable to operate above the hydrate-forming temperature. Maintaining temperatures above 35°C (Figure 3) prevents compressor breakdown and plugging, as well as plugging of the pipeline and injection well. Acid gas obtained after the removal of H$_2$S and CO$_2$ from the sour gas is usually saturated with water vapor in the range of 2 to 6%. The solubility of water in both H$_2$S and CO$_2$, hence in acid gas, decreases as pressure increases up to 3-8 MPa, depending on temperature, after which it dramatically increases. The solubility minimum reflects the pressure at which the acid-gas mixture passes into the dense liquid phase, where the solubility of water increases substantially with increasing pressure due to the molecular attraction between these polar compounds [11, 12]. This property is used in naturally dewatering the acid gas by compressing the gas from about 100 kPa to around 8 to 10 MPa for injection, thus reducing the water content to less than 0.5 mole% to avoid pipe and well corrosion [11, 12, 13].

![Figure 3: Typical operating conditions for acid gas injection showing the compression and dehydration cycle, transportation from the gas plant to the injection well, and injection, in relation to the acid gas phase and hydrate forming conditions (after [14]).](image)

Most of the compressor drivers are electric motors in Alberta, and natural-gas fuelled engines in British Columbia. In Alberta, adding gas engines to an approved plant requires a thorough review of NO$_x$ emissions for the plant. Also, the maintenance cost of electric motors is less than that of natural gas engines. Most installations require only four stages of compression. Maximum compressor discharge injection pressures range from 2.8 MPa to 8.9 MPa. Generally, the compressed acid gas is injected in a pressure-temperature range where the liquid phase is stable, resulting in an appreciable head pressure being generated due to the height of column of this liquid in the wellbore, thus lowering the required compressor discharge pressure. To avoid cavitation, the acid gas must not enter the two-phase region during compression. While sour gas or sweet gas that is injected in cycling (natural gas storage)
schemes requires dehydration, many acid gas disposal schemes do not need to dehydrate the acid gas. By the 4th stage in a cycle (Figure 3), compression at pressures between 3 and 5 MPa will tend to dewater the acid gas if there are no hydrocarbon impurities present [10]. Further compressing the acid gas increases the solubility of water in the acid gas, such that residual excess water dissolves into the acid gas, and more than counteracts the decrease in solubility due to inter-stage cooling. In the majority of cases dehydration is supplied by the compression cycle and only in a few cases tri-ethylene glycol, refrigeration or a desiccant is used.

Pipelines reflect the fact that most of the current acid gas disposal projects handle small rates, in that most of the lines have a diameter of 60 mm (2 inch nominal). The line lengths in many instances are short, reflecting the fact that operators have either drilled the disposal well near the plant, or are using a prior existing well adjacent to the plant. The design stress levels, and especially the actual operating stress levels, are low, again reflecting the low injection pressure levels. Most lines are made out of carbon steel, although many of the short lines are made out of stainless steel. Emergency shutdown valves are installed at both ends of the disposal pipeline. The pipelines connect the plant compressors to the injection wells, and range in length from 100 m to 20 km, with diameters ranging from 48 to 168 mm and wall thickness from 3.2 to 11 mm.

The bottom hole pressure needed for injection is provided by the pressure at the wellhead and the hydrostatic weight of the acid gas in the well, minus friction losses down hole and across perforations. The wellhead is equipped with a pressure control valve that regulates pressure. Regulations require that all disposal wells be equipped with downhole packers, to protect the casing strings. Casing depths range from 856 to 3,335 metres. Casing diameter ranges from 114 to 244 mm, while the tubing diameter ranges from 60 to 244 mm. Many wells are equipped with L-80 grade tubing, which is considerably stronger than would be required for the experienced injection pressure levels. To protect the tubing against the possibility of internal corrosion, several operators have elected to use internally coated tubing. If the gas is undersaturated in water content, corrosion is minimal in any case. Subsurface safety valves have been installed in many tubing strings, as a safety measure in the unlikely case of backflow of acid gas from the formation. Many tubing strings are equipped with premium threads, to avoid potential tubing leaks. Overall, many precautions have been applied in well completions to ensure safe operations.

**SUBSURFACE CHARACTERISTICS**

Table 1 summarizes the characteristics of the geological media into which the acid gas is injected. In 29 cases injection takes place in carbonate rocks and in 19 cases in siliciclastics. In most cases shales and shaly siliciclastics constitute the overlying confining unit (top seal), but also tight limestones, evaporites and anhydrites are present. Reservoir containment of the acid gases by geological trapping is discussed in more detail in [15]. Other trapping types for acid gas are hydrodynamic traps formed by deep aquifers, discussed in [16], and mineral traps discussed by [17] and [18]. The initial formation pressure is generally subhydrostatic with respect to freshwater, except for one case, in the Foothills in northeastern British Columbia, where the injection reservoir was initially slightly over-pressured. 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. In 10 cases the formation pressure at start-up was below the critical pressure of CO₂.

**TABLE 1: CHARACTERISTICS OF THE AQUIFERS AND OIL OR GAS RESERVOIRS USED FOR ACID GAS INJECTION IN WESTERN CANADA.**

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average injection depth (m)</td>
<td>824</td>
<td>3432</td>
</tr>
<tr>
<td>Formation thickness (m)</td>
<td>4</td>
<td>276</td>
</tr>
<tr>
<td>Net pay (m)</td>
<td>2</td>
<td>100</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>4</td>
<td>30</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>1</td>
<td>4,250</td>
</tr>
<tr>
<td>Formation pressure (kPa)</td>
<td>5,915</td>
<td>35,860</td>
</tr>
<tr>
<td>Formation temperature (°C)</td>
<td>26</td>
<td>110</td>
</tr>
<tr>
<td>Water salinity (mg/l)</td>
<td>19,740</td>
<td>341,430</td>
</tr>
<tr>
<td>Oil gravity (°API)</td>
<td>16</td>
<td>68</td>
</tr>
<tr>
<td>Gas specific gravity</td>
<td>0.573</td>
<td>1.121</td>
</tr>
</tbody>
</table>
In-situ phase and thermodynamic properties of the formation brines and acid gases are discussed in more detail in [19]. For the case of acid gas being injected into depleted oil reservoirs, the oils are medium to very light (24° API to 68°API), and in one case the oil is heavy (16°API). Acid gases generally have a lower minimum miscibility pressure than conventional hydrocarbon gases, therefore, they can be used in enhanced oil recovery (EOR), as it was done at one site [20]. Reservoir gases are generally light (specific gravity less than 0.75). Because acid gas is generally heavier than these reservoir gases, it may also be considered for use in enhanced gas recovery. More details about the subsurface characteristics of the acid-gas injection in western Canada can be found in [21].

CONCLUSIONS

By the end of 2003, approximately 2.5 Mt CO$_2$ and 2.0 Mt H$_2$S have been successfully injected into deep hydrocarbon reservoirs and saline aquifers in western Canada. This experience shows that CO$_2$ storage in geological media is a technology that can successfully be expanded to and applied in large-scale operations that will reduce CO$_2$ emissions into the atmosphere from large CO$_2$ point sources. The size of the operations approved to date in western Canada is relatively small, with approved injection rates and volumes generally less than 0.1 million m$^3$/d and 1000 million m$^3$, respectively. The technology and experience developed in the engineering aspects of acid-gas injection operations (i.e. design, materials, leakage prevention and safety) can be easily adopted for large-scale operations for CO$_2$ geological storage, since a CO$_2$ stream with no H$_2$S is less corrosive and less hazardous. No safety incidents have been reported 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. Given that H$_2$S is more toxic and corrosive than CO$_2$, the success of these acid-gas injection operations indicate that the engineering technology for CO$_2$ geological storage is in a mature stage. 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.

REFERENCES


