ACID GAS INJECTION – THE NEXT GENERATION

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ABSTRACT

Acid gas is a mixture of carbon dioxide and hydrogen sulfide and is a byproduct of the sweetening of natural gas. Acid gas injection (AGI), an environmentally friendly method of dealing with the acid gas, is basically the compression of a low-pressure stream to sufficient pressure to achieve injection. The fluid is transported via pipeline to an injection well where it travels downward into a selected injection reservoir. AGI is a mature technology on a small- (less than 10 MMSCFD [283×10^3 Sm^3/day] of injected fluid) and medium-scale (less than 100 MMSCFD [2830×10^3 Sm^3/day]). Some producers are now considering injection on a larger scale (greater than 100 MMSCFD). Many of the principles used to design the small and medium sized injection schemes can be transferred to the larger schemes. However the larger injection schemes pose new challenges.

The injection of carbon dioxide either for sequestration purposes (CCS) or for enhanced oil recovery (EOR) shares many characteristics with AGI. The lessons learned from AGI are directly applicable to the injection of a CO_2-rich stream.

In this paper the state of the art for AGI is reviewed. The main difference between the current injection schemes and some of those proposed is the volume of fluid to be injected. Some of the newer projects are suggesting the injection of significantly larger volumes than are currently being injected. Some of the differences between the small and large-scale injection schemes are discussed. The main focus of this paper is on the surface facilities, but wells and the injection reservoir are also discussed.

INTRODUCTION

The conventional acid gas injection project is composed of four essential parts: 1. a compressor, 2. a pipeline, 3. an injection well, and 4. a disposal reservoir. However there are two additional pieces of equipment that may be require: 5. a dehydration unit and 6. a pump. A block diagram for AGI is presented in Fig. 1. These are the basic components regardless of the size of the injection scheme; the difference arises in the details of the particular scheme.

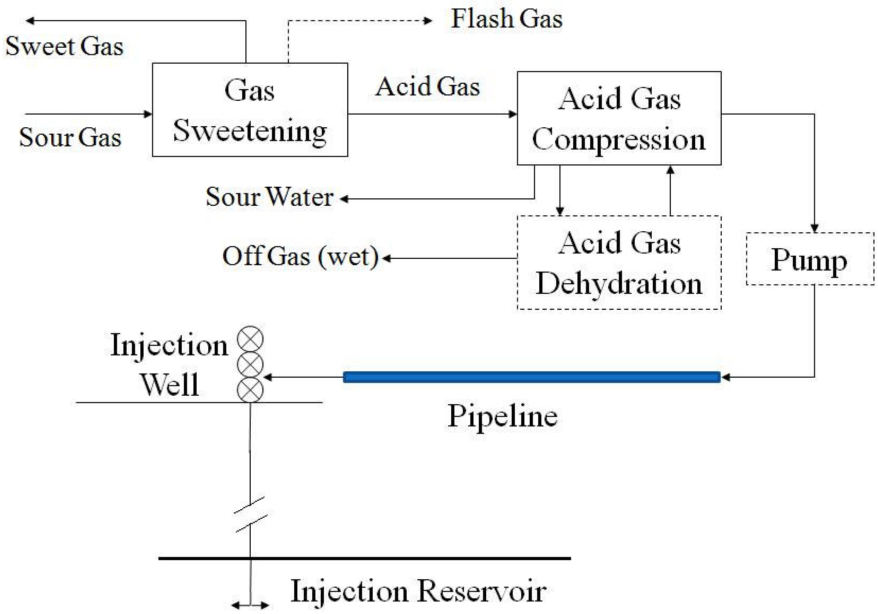

Fig. 1 Block Diagram for the Acid Gas Injection Process

In many injection schemes compression and cooling alone is sufficient to dehydrate the gas to a point where neither free water nor hydrates are a problem. This will be examined in more detail later in this paper. However in some cases additional dehydration may be required. When dehydration is necessary, some compression is required because the gas cannot be dehydrated at pressures less than 250 kPa. There are at least two reasons for this: 1. The water content of a low pressure stream is very high. and 2. The actual flow rates are quite large and thus large diameter equipment would be required to process a relatively small stream. Since dehydration is not always required, the lines connecting it to the block diagram are dashed.

For most injection schemes compression alone can achieve the pressure required to achieve injection. However if the injection pressure is high, then a pump might be necessary beyond compression. After compressing the acid gas to about 1000 psia (69 bar) the fluid is in the liquid phase or in a dense fluid state and thus can be pumped to higher pressure. Again, for this reason the pump is connected to the block diagram using dashed lines.

Another dashed line on the bock diagram is the flash gas. In many amine plants the rich amine from the absorber is sent to a flash tank where the pressure is dropped from the absorber pressure to about (50 psia). The gas that is released from this pressure reduction is largely hydrocarbon that was co-absorbed. This stream also contains some H_2S and CO_2. In many cases this can be added to the fuel gas system, even though it is sour. The overall H_2S in the fuel gas may be sufficiently low that it can be used as fuel in internal combustion engines or indirect heaters. The question is, can it be added t the acid gas stream and be disposed as a single stream?

The fundamentals of conventional acid gas injection (i.e low volume schemes) have been discussed in the literature and will not be repeated here in any detail. The focus is on the larger injection schemes that are currently in operation and the even larger schemes that re in the future.

THE FIRST GENERATION

The First Generation was characterized by relatively low injection volumes. These were well suited for the small sulfur producers (less than 10 tonne/day), which are quite common in Western Canada.

The first injection scheme was that of Chevron at Acheson, near Edmonton, Canada, which started in 1989 – twenty years ago and is still in operation today. This scheme is typical of the First Generation scheme. The injection volume is very small less than 0.5 MMSCFD. The acid gas injected at this site is approximately 90% CO_2 and 10% H_2S. It is compressed using a small reciprocating compressor (Ariel JG/4) to a pressure of 550 psia (38 bar). Because of the high CO_2 concentration dehydration is required and this was achieved using a TEG dehydration unit. The gas is injected into a sandstone formation. For more information about this project see Lock (1997) and Bosch (2002).

The scheme at Acheson used a glycol dehydration unit to reduce the water content of the acid gas to an acceptable level. Many of the First Generation schemes take advantage of the unique thermodynamics of acid gas systems and use compression and cooling alone to achieve the dehydration (Carroll, 2002).

Since that time there have been more than 50 similar injection schemes, but the point of this paper is to look forward and not to review the existing small injection schemes. However, a few other First Generation injection schemes have been described in the literature. These include Wayne-Rosedale, Alberta, Canada, (Ho et al., 1996); Dumas, Texas, USA (Whatley, 2000); Lisbon, Utah, USA, (Jones et al., 2004). Puskwaskau, North Normandville, West Culp, Rycroft, all in Alberta Canada (Maddocks and Whiteside, 2004); and Artesia, New Mexico, USA, (Root et al., 2007).

THE SECOND GENERATION

The Second Generation schemes were larger in terms of volumes injected but shared many of the same characteristics of the First Generation. Most of the Second Generation schemes currently in operation are summarized in Table 1. At present, these are the largest injection projects in the world.

Table 1 Summary of Some of the Current Second Generation Injection Schemes

Location	Operator	Start-up	Rate (MMSCFD)	H_2S (mol%)	CO_2 (mol%)
Sleipner, North Sea	StatoilHydro	1996	50	0	100
Kwoen, BC, Canada	Spectra	2002	33	79	20
LaBarge, WY, USA	ExxonMobil	2005	65	65	35
Qatar	RasGas	2005	88	25	73
In Salah, Algeria	BP Sonotrach	2004	50	0	100

A brief discussion of the Sleipner as an example of a Second Generation scheme is presented here. More details about the schemes can be found as follows: Kwoen in Palla et al. (2004) and Adams (2007); LaBarge in Benge and Dew (2005) and Wall and Kenefake (2005); RasGas in Kenefake et al. (2007); and In Salah in Wright (2009).

The first of the Second Generation schemes was the offshore project at Sleipner in the North Sea. Although most refer to this as a carbon sequestration project, it has all of the elements of an acid gas injection project as shown in Fig. 1.

Injection is into a single well that has a long horizontal leg. The injection zone, the Ulstira sandstone, has a high permeability 1 to 8 darcies and is at a depth of approximately 1000 m. The injection well is a 7-in monobore design in order to minimize pressure losses due to fluid friction (Baklid et al., 1996). The compressor at Sleipner is a four stage Dresser-Rand centrifugal machine, with a discharge pressure of 66 bar (Underbakke, 2007).

THE NEXT GENERATION

The Next Generation of injection schemes will be larger than 100 MMSCFD and remember this is the rate for the injected gas not the feed rate to the plant. For example, a plant producing 100 MMSCFD of injection gas could be, for example, 1 BSCFD of feed gas that contains 10% acid gas (H_2S + CO_2). So these are large processing units.

As an example of such a large plant, consider the Shah development in Abu Dhabi. The design has just completed FEED and the plant is designed to process 1 BSCFD of raw gas containing 23% H_2S and 10% CO_2. Because of the downstream processing essentially all of the CO_2 will be removed – no CO_2 slip. This plant will produce an acid gas stream with a flow rate of 330 MMSCFD and the equivalent of about 10,000 tonne of sulfur per day (Schulte et al., 2009). There are no plans for acid gas injection at this location, but this is presented as an example of the size of projects currently being considered. The current plan is for the production of elemental sulfur.

There are at least three factors motivating such large gas plants to consider acid gas injection:

1. The volatility in the sulfur market. In late 2007, the spot price for sulfur started to rise sharply and by the middle of 2008 it peaked at around $800 (US)/tonne. However, by the beginning of 2009 prices had fallen to near $50/tonne (Sulphur, 2009). This is an example of the volatility of the sulfur market.
2. The large space required to block a large amount of sulfur. The Shah development described above will produce about 80,000 ft^3 of sulfur per day (2270 m^3).
3. Reducing carbon emissions. Carbon dioxide is implicated in the global climate change. Many companies are looking at ways to reduce their carbon emissions and injection is a possible option.

Alternatively the flue gas from a power plant would be this volume. A 750 MW coal-fired electrical plant can emit up to 5×10^6 tones per year of carbon dioxide, which is equivalent to 250 MMSCFD of CO_2. An electrical generation plant of this size can supply enough electricity for a city of 1,000,000 people. (This information comes from various sites on the internet and is provided as is. No reference will be provided.)

Currently there are no Next Generation schemes in operation. However, the basic components of the injection schemes remain the same. Specific details will be discussed in the subsequent sections of this paper.

DESIGN CONSIDERATIONS

The basic components of all injections schemes are the same regardless of the volumes injected. However there are some significant differences. In the sections that follow the important parts of the injection process are reviewed and difference between the the current schemes and the Next Generations are presented.

Reservoir[†]

The first problem with designing a large injection project is finding a reservoir to accept the injected fluid. Some simple criteria for selecting a formation to place the injection fluid are:

1. Contain the acid gas injected
    a. Hold the total volume injected
    b. Have an impermeable cap rock to prevent leakage to shallower formations
    c. No leakage through the injection well or other wells penetrating the injection zone

[†] Although the author of this paper has no special expertise in the area of reservoir engineering, this section is based on his involvement with many injection projects over the last 15 years.

2. Minimal interactions between the native reservoir components (rock, liquid hydrocarbons, and natural gas) and the injected gas. If there are significant interactions this will impair
3. The permeability of the injection zone must be such that excess pressure is not required to force the fluid into the rock. A low permeable zone may require multiple injection wells.
4. Typically a gas that contains H_2S should not be injected into an otherwise sweet zone.

Acid gas is currently injected into both sandstone and carbonate formations, although carbonate rock is more susceptible to negative injections with the acid gas. Also acid gas is currently injected into both aquifers and hydrocarbon formations. In some case the acid gas is injected for enhanced recovery of oil, however such operations must be prepared for the souring of the produced fluids (increasing H_2S concentration).

For the small injection schemes the volume of the reservoir this is usually not a problem. Once compressed to high pressure the actual volume of the injected fluid is quite small. However for the large schemes the size of the reservoir is important. One possible reservoir is the original producing reservoir. This assures that the reservoir can hold the injected volume, since it is only a fraction of the amount removed. On the plus side the injection helps maintain reservoir pressure and may lead to improved recovery of the original gas in place. On the negative side, injection acid gas will lead to reservoir souring – increased hydrogen sulfide concentration in the produced gas.

It is worth noting that a t both LaBarge and In Salah the gas is injected into the water leg of the producing zone some distance from the producing wells.

Injection Well

The following formula can be used to estimate the required wellhead pressure (injection pressure) in order to achieve injection:

Wellhead Pressure = reservoir pressure
+ pressure drop due to formation porosity and permeability
+ pressure drop due to skin damage (1)
+ pressure drop through perorations
– static head of tubing fluid
+ frictional pressure drop

The first four terms on the right hand side of this equation are lumped together and called the sandface pressure.

In the conventional small injection schemes only a single well is required and spare wells are usually not used. Typically the required injection pressure is merely the sandface pressure minus the hydrostatic head of the injected fluid. Pressure drop due to fluid friction is negligibly small. Furthermore, the difference between the sandface pressure and the reservoir pressure is very small. In terms of actual flow rate the injection is quite small the pressure drop due to flow through the porous formation is quite small.

In Second Generation schemes as well as the Next Generation all of the terms in Eqn. (1) are significant. One way to reduce the injection pressure is to use horizontal wells. The well reaches the depth of the injection zone and then turns horizontal to penetrate the zone. This significantly improves the injectivity and reduces the required injection pressure.

For the large injection schemes the pressure drop in the tubing may not be small, even though larger diameter tubing is used. Moreover, the pressure drop due to the flow in the reservoir can be significant especially if the permeability is low. Ergo large injectors may opt for more than one well.

Furthermore the wells are system critical and the operator may choose to have stand-by wells in case one of the injectors requires a workover. Thus plant production can continue during the workover.

Compression

The small reciprocating compressors are ideally suited for the low flow rate, low suction pressure, and high discharge pressure encountered in the conventional injection schemes. They tend to be quite reliable and often operators have only a single compressor.

With larger injection schemes, centrifugal compressors are more attractive, simply to handle the larger volume.

Furthermore because compression is system critical, if the compressor goes down the entire plant must be shut in, often there is additional compressor capacity available. These injection schemes will undoubted specify 3×50% or 4×33% compressor capacity.

Turndown for the small schemes that use a combination a reciprocating compressor and an electric motor drive is relatively easy to achieve using speed control. The performance of a centrifugal machine is more closely tied to the speed and merely reducing the speed may not be sufficient to achieve the desired turndown. This is another reason for having multiple machines. For high turndown it may be necessary to recycle the gas in order to keep the compressor loaded.

Water Knock-out

One of the tricks in the design of a compressor for acid gas injection is the optimization of the interstage pressure to achieve optimal water knock out. Such a design can be used regardless of the size or type of compressor used.

Figure 2 shows the water content for several acid gas mixtures. From this figure one can see the two types of water content behavior for acid gas mixtures: 1. Minimum in the water content (for pure CO_2) and 2. Liquefaction of the acid gas (pure H_2S). In the design of an acid gas compressor one tries to have the discharge from the penultimate stage either in the minimum region or near the point where the acid gas liquefies. Thus compression through the last stage results in a mixture that is undersaturated with respect to water. More details about this and other aspects of compressor design for acid gas injection can be found in the paper by Carroll and Maddocks (1999).

Pipeline

In the early schemes the pipelines were quite short, less than a mile in length. However as there became more comfortable with designing and operating these schemes the pipelines became longer and longer. Pipelines greater than 10 km (6 miles) in length are currently in operation.

For the low flow scheme pipeline diameters were 2- or 3-in, not necessarily based on flow consideration but these are the smallest diameter pipe than can be laid over long distances. With the larger flow schemes pressure drop in the pipeline must be taken into consideration in the design.

In addition, there is a considerable safety factor. Larger diameter pipe can hold significant more acid gas and thus leaks from larger diameter pipe pose more safety and environmental concerns. For example 8-in Schedule 80 pipe has a volume of 1621 ft^3[act] per mile versus a 2-in line that holds only 108 ft^3[act] per mile.

Furthermore, a larger injection scheme may require more than one injection well and the fluid must be distributed to all of the wells. This means that there is a network of lines rather than just a single line from plant to well.

SUMMARY

The Next Generation of acid gas injection projects will be very large and poses many technical challenges. Some of these challenges have been outlined in this paper. These include the need for large compressors and multiple compressor trains, and several injection wells with a pipeline network to deliver the gas to the wells. Like many new process other challenges will almost certainly present themselves in detailed design stage and during operation.

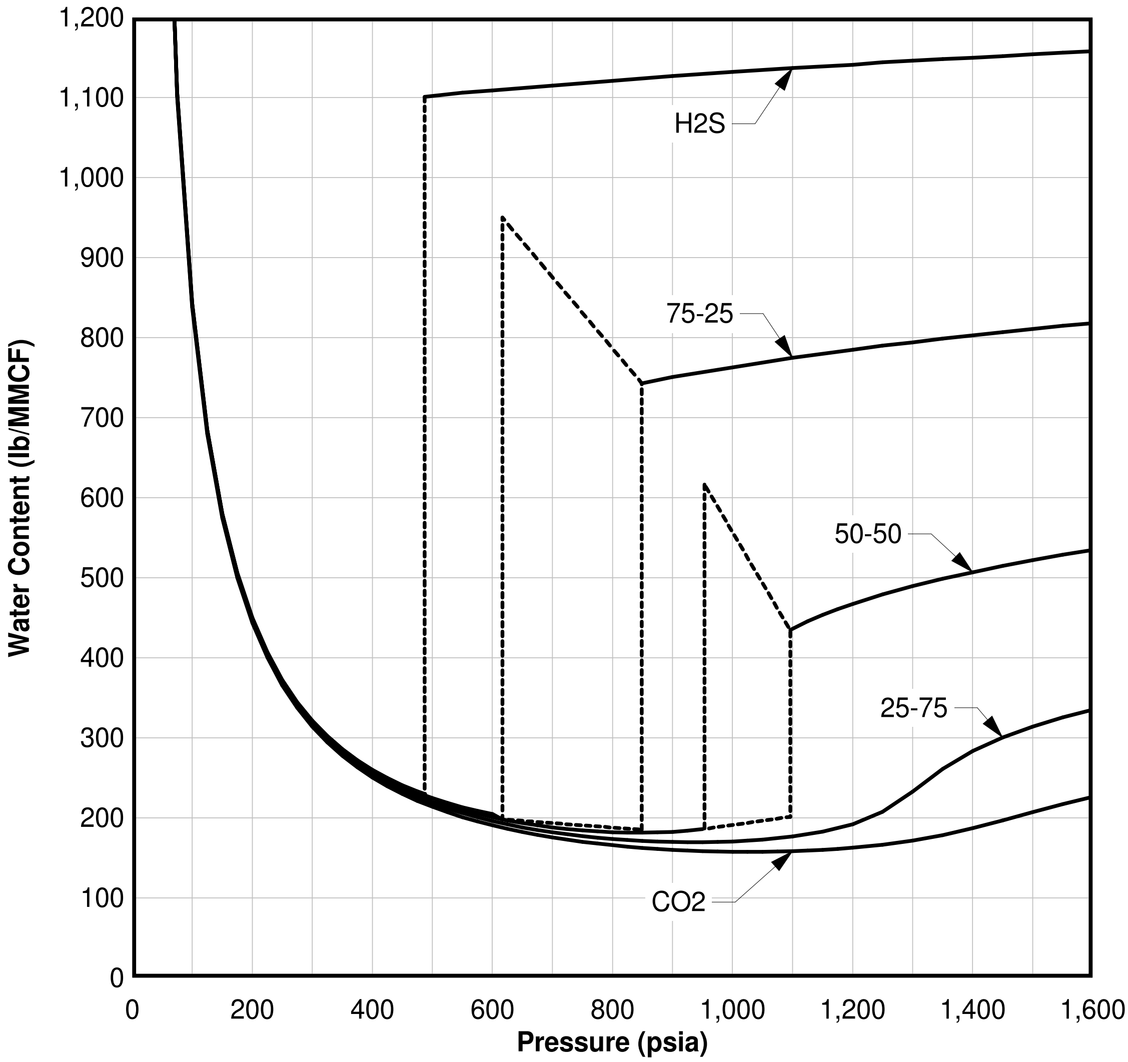

Fig. 2 Water Content for Five Acid Gas Mixtures at 50°C: Pure H_2S, 75% H_2S (75-25), 50% H_2S (50-50), 25% H_2S (25-75), and pure CO_2

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