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CARBON CAPTURE AND STORAGE EXPERIENCES FROM THE SLEIPNER FIELD

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Abstract
The Sleipner West Field, which came on stream in 1996, is the largest gas/condensate field in the Sleipner area. Having a higher carbon dioxide (CO_2) content (9 mole%) than the gas export quality specifications (2.5 mole%), it was necessary to handle the excess without harming the natural environment. Capture and storage of CO_2 was selected and has got high attention as an option for limiting CO_2 emissions from the use of fossil fuels. CO_2 capture is premised on the safe long-term storage of CO_2 in geological formations. An amine plant was installed at the Sleipner T platform to extract the CO_2 from the reservoir gas, which is injected and stored 800-1000m below sea level and 2.5 km east of the Sleipner A platform in the Utsira Formation - a water-filled aquifer. Until now, about twelve million tonnes of CO_2 have been injected. Selected experiences gained since startup of the CO_2 capture and injection process is presented in this paper. The importance of fundamental knowledge related to thermodynamics and kinetics of chemical absorption at high pressure is highlighted.

Keywords: CO_2, Sleipner Field, Absorption, Amine, CO_2 storage

1. Introduction

The Statoil-operated Sleipner West field is one of the largest gas producers in the Norwegian sector of the North Sea, with a daily gas export capacity of 20.7 million cubic metres and a daily output of 60 000 barrels of stabilized condensate (light oil). The Sleipner West field was discovered in 1974. This development comprises two platforms, one unmanned well head platform, Sleipner B (SLB), and the gas treatment platform, Sleipner T (SLT). SLT is located on the Sleipner East field and connected to Sleipner A by a bridge connection. Untreated gas from Sleipner Vest is being transported in a 12 km pipeline to Sleipner T for CO_2 removal.

The Sleipner Vest gas/condensate field is situated on the Sleipner Terrace (to the east of the Utsira High) in the southeastern part of the Viking Graben (North Sea). The field is located 240 km west-southwest of Stavanger, Statoil is the operator with 58.34% of the rights and ExxonMobil Norway has 32.23%, while Total E&P Norway has the remaining 9.41%. The in-place hydrocarbon volumes are 160 GSm^3 gas and 70 MSm^3 of unstabilized condensate.

Gas/condensate production in the Sleipner area started in 1993 from the Sleipner East Ty Field (Figure 1). The gas is transported, together with Troll Field gas, through the Zeepipe and Statpipe pipelines to continental Europe. The condensate is piped to Kårstø (Norway) where it is separated into stabilized condensate and natural gas liquid (NGL) products.

During field development planning (1990), it was realized that the 4 to 9.5 per cent CO_2 content in the natural gas would have to be reduced to less than 2.5 per cent if it were to be fed directly into sales gas pipelines to Europe. A small team of technical experts came up with the unprecedented idea of capturing the CO_2 offshore and injecting it into a saline aquifer beneath the Sleipner installations. In this way, the Sleipner asset would minimize CO_2 emissions – the prime motive – while avoiding environmental taxes. Despite its pioneering nature, this became the partner approved solution.

Of various possibilities, an Elf-patented separation process using MDEA (methyldiethanolamine) with an activator was selected for CO_2 capture, because it was deemed cheaper to run and more compact than competing systems. One of the greatest challenges, however, was to scale down the process plant sufficiently so that it could be accommodated on an offshore platform. Even so, the 'miniaturized' version of the extraction module weighed 8 200 tonnes – the heaviest module ever to be lifted offshore – and measured 50 m x 20 m x 35 m.

By the time the field came on stream in 1996, the Sleipner organization had notched up two world firsts: the installation of a large-scale offshore CO_2 extraction plant at the Sleipner T (Treatment) platform; and the facilities for saline aquifer injection from the Sleipner East A platform.

The following important issues have continually been in focus since the Sleipner West field started production

- optimization of the amine plant to increase its CO_2 extraction capacity
- increasing and stabilizing the injection capacity
- monitoring the behaviour of the stored CO_2

The experiences achieved in the Sleipner's CO_2 handling project since 1996 have been widely accepted and important for other CO_2 storage projects. The first oil and gas development in the Barents Sea, an area which requires high environmental standards, has been made possible based on these experiences[3]. Selected experiences gained since startup of the CO_2 capture and injection process on Sleipner is presented in this paper. The paper is based on various publications[1-5] related to CO_2 capture at Sleipner.

The various start-up challenges that arose during production have been solved, and today the method of CO_2 extraction in an amine plant and its injection into a shallow aquifer for storage has proved to be an excellent example of how to produce reservoirs with high CO_2 contents while limiting environmental consequences.

The CO_2 is stripped from the well stream by adding the chemical component MDEA (methyl-di-ethanol-amine). The separation equipment was installed in one of the modules on the SLT platform, while the other SLT module is used for gas processing. The CO_2 content in the gas stream is reduced from about 9 to an average of 3 mole%. After extraction, the gas is transported to the Sleipner A platform and then to the Sleipner Riser platform (SLR) for export. At SLR, the gas can be blended with deliveries from the Troll Field. Since 1996, about 0.8 – 1.0 million tonnes per year of extracted CO_2 has been injected into the shallowly buried, water-filled Utsira Formation (sandstone), solely to minimize emissions to the atmosphere.

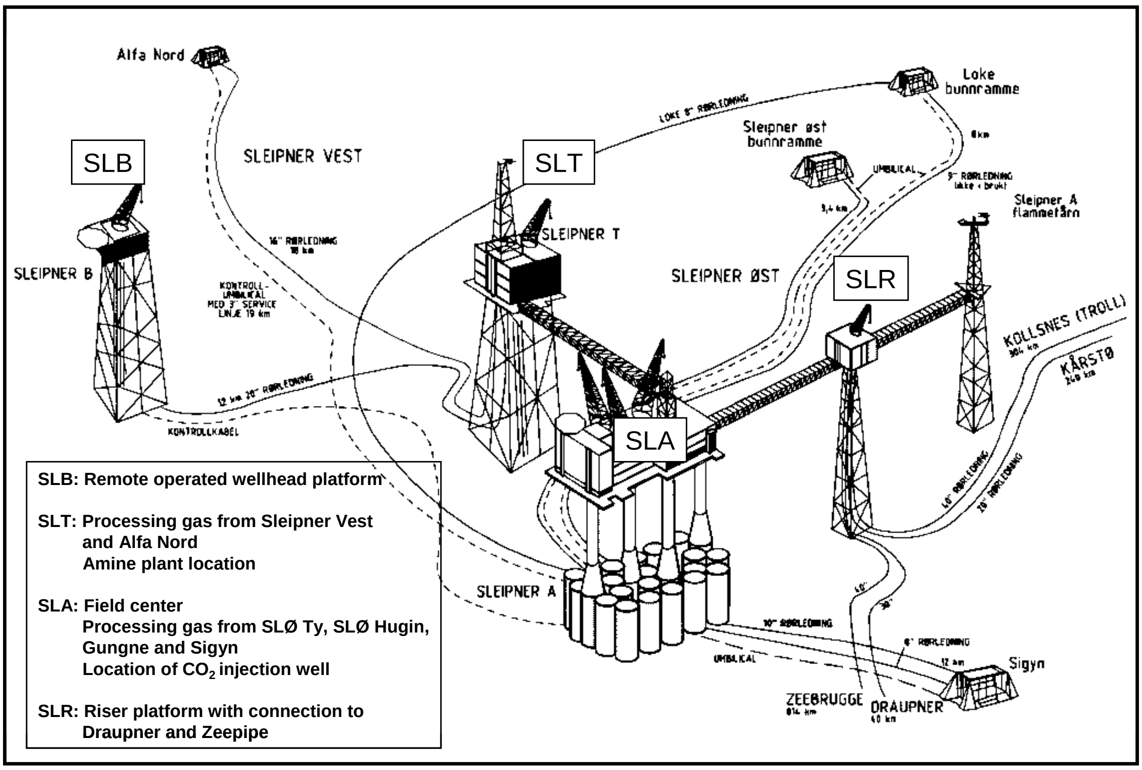

Figure 1. The Sleipner installations

The second development phase was planned to include a compression platform (SLC), connected by a bridge to the SLB. However, it was decided in 2001 that the SLT would be modified by lowering the inlet pressure to the SLT, instead of building the Sleipner C platform. These modifications were carried out between 2002 and 2004, including both low-pressure production (for two years) and modification of one of the export compressors to pre-compression. The inlet pressure has gradually been reduced to 35 bar, and the recoverable gas and unstabilized condensate have been increased by 35 GSm^3 and 9 MSm^3, respectively.

Phase three covered development of the northern part of the field, Alfa Nord (see Figure 1). Production from this area started in October 2004 via four subsea wells connected to the SLT platform by an 18 km pipeline. The Sleipner West wells were completed using 13% Cr production tubing because of the high CO_2 content. Corrosion was therefore not expected and is not observed to be a problem.

2. The Sleipner amine CO_2 removal plant

CO_2 removal from natural gas can be done in several ways. The most common process is chemical absorption using alkanolamines. At Sleipner an alkanolamine absorption process was chosen, which is schematically illustrated in Figure 2. The amine plant is situated on the SLT platform and contains absorber and stripping columns, pressure/storage tanks, heat exchangers, Pelton turbines and filters. The Pelton turbines recover the energy as the amine pressure is reduced into the flash regeneration system. This gives five megawatts of power for the platform, thereby reducing platform-based carbon dioxide emissions. The amine plant, which weighs about 9000 tonnes and is 35 m high, had a cost of NOK 2 billion (about USD 300 million) in 1996. The absorption process reduces the CO_2 content in the natural gas to about 3.0 mole%. The CO_2 is removed in two parallel absorbers towers using a methyldiethanolamine (MDEA) based process operating at around 100 bara and 70°C. Afterward, the pressure of the amine is reduced in Pelton turbines. The co-absorbed hydrocarbons and some CO_2 are stripped off in the first flash drum, operating at approximately 15 bara and 70°C, and re-circulated into the natural gas feed. The main regeneration of the amine is done in the second flash drum, operating at a pressure around 1.2 bara and generating semi-lean amine. 10% of the amine solution is fully regenerated in an amine stripper column, generating lean amine. No activator is currently added to the amine. The total amine circulation rate is around 3300 m^3/hour.

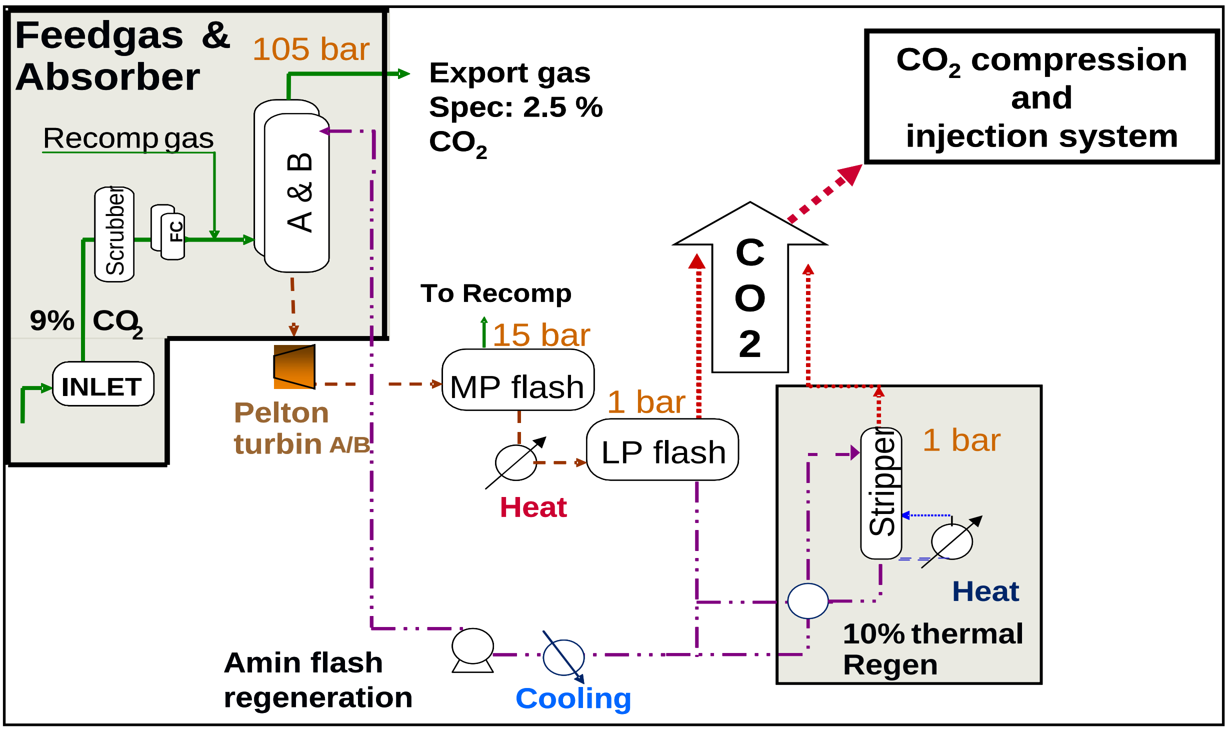

Figure 2. Flow diagram for the Sleipner CO_2 removal system

As already mentioned, the amine plant should ideally reduce the CO_2 content in the dry gas from 9 to 2.5 mole% to fulfill gas quality specifications. During early start-up (Oct-Nov 1996) the treated gas CO_2 content was generally between 2.7-3 % at 50 % of gas production design capacity. As gas rates increased to design values the CO_2 content rose to 3.5-4 %.

Although the resulting CO_2 content from the plant has been higher than 2.5%, the amount has continually decreased over the years due to improvements made to the amine regeneration plant, the absorber columns and the feed gas system. The start-up of Alfa Nord in October 2004 (lower CO_2 content) has also contributed to a reduction of the CO_2 content in the commingled export gas.

In the feed gas system, liquid hydrocarbon carry-over from the separators/scrubbers to the amine plant was greater than expected. This resulted in foaming problems, unstable absorbers, a high consumption of antifoam agents, and a reduced absorption rate. Improvements have been made by developing and installing improved separation/scrubber technology, including Statoil's prize winning in-line technology for phase splitting.

Natural gas, requiring treatment, passes through two, large absorption columns. Initially the absorbers experienced hydraulic problems when operated at the design rates: the operation was unstable, with liquid and gas carry over at the top and the bottom of the absorber. These problems have been overcome by re-designing the gas and liquid distributor, improving the degassing function, and changing the packing material from being structured to randomly packed. These measures have led to an increase in the hydraulic capacity of the gas (115%) and the liquid (140%).

However, the prime reason for insufficient CO_2 removal is the lack of cyclic capacity in the Sleipner amine regeneration plant. The original design was based on what proved to be over optimistic vapour-liquid equilibrium data, both for the reaction between amine and CO_2 and with regard to the effectiveness of the activator. Statoil researchers have carried out extensive work on CO_2-amine equilibrium and the effect of activators, much of it involving laboratory studies using genuine fluids under ambient conditions[4-5]. Initially, an activator (fast reacting amine) was used to increase the reaction rate. However, experience at the plant and the results of Statoil R&D work have shown that the performance of the amine system is either unaffected (or even negatively affected) by activator concentration, contrary to most plants.

Over the years the plant's stability has been improved, production has increased to 110 %, and operational costs (chemicals, filters) have been substantially reduced from approximately NOK 50 million K (USD 7.5 million) to NOK 10 million (USD 1.5 million).

In the last two years, the CO_2 content in the gas emerging from the amine plant (SLT export gas) has been reduced from about 3.5 % to below 3 %. Moreover, in 2003, it was found that by increasing the amine circulation rate and the heating of the system, the CO_2 levels were kept below the 2.5 mole % specification. To achieve this, the spare amine circulation pumps have to be kept running, but this is not recommended for continuous daily operation.

The gas sales quality specification has been met by injecting a mixture of the SLT export gas and the SLA export gas in the Sleipner East Ty Field, which initially had a very low CO_2 content (0.3 mole%). In addition, it is possible to blend with Troll gas deliveries at the Sleipner riser platform (SLR), connecting SLA to the gas transport pipelines.

To reduce the CO_2 content from 9 to 2.5 mole %, the CO_2 removal and injection system requires about 160 MW for heating, cooling, pumping and compression. This energy demand is about 42 % higher than originally planned. Some of this increase is due to an increased circulation rate and a higher operating temperature. CO_2 removal/regeneration is by far the most energy consuming part of the system, accounting for more than 75% of the total energy demand. Approximately 8% of the energy demand is provided by an internal heat exchange stream, although this too is somewhat lower than anticipated.

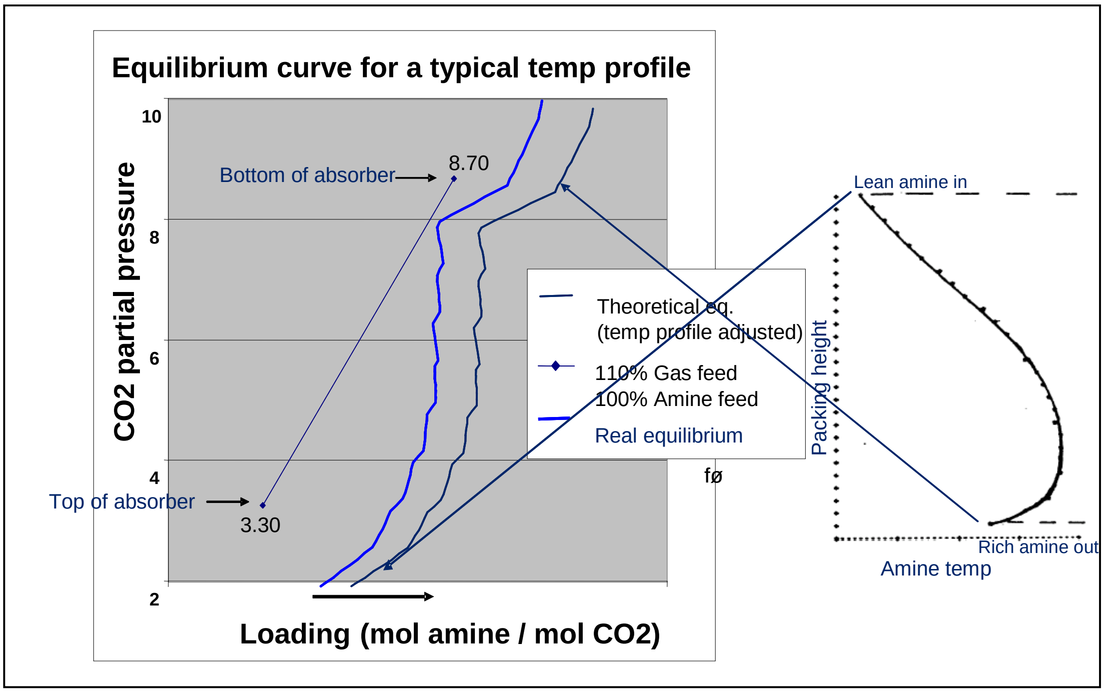

Figure 3. The effect of increased system pressure on the operational and the temperature corrected equilibrium line of an alkanolamine process.

2.1 Fundamental studies regarding high pressure absorption in MDEA

A new thermodynamic model developed for Statoil[4-5] was used to evaluate the effect of system pressure on the capacity of MDEA solutions. It was observed that high total pressure has a considerable effect on the fugacity of CO_2 in high-pressure natural gas system. For a given partial pressure of CO_2, experiments and calculations showed a decreased CO_2 absorption capacity of aqueous MDEA solutions at increased natural gas system pressure. The effect of increased system pressure leads to a lower driving force for CO_2 absorption than we could expect from low-pressure data. This is illustrated in Figure 3. The equilibrium line will move close to operational line of the absorber when the system pressure is increased. This could lead to situations where the absorber operates close to equilibrium (pinched) in parts of the column. The thermodynamic model was used to evaluate the operational possibilities for improving the Sleipner CO_2 removal plant. It was shown that the operation was closer to equilibrium than previously thought. Addition of an activator to the Sleipner amine was not recommended, because of the low or possible negative effect on cyclic capacity. Exploiting the Statoil Research Centre's laboratory facilities has given insight and experience on how to operate high pressure CO_2 capture plants. This has been actively used to obtain stable operation at the Sleipner CO_2 removal plant.

3. The Sleipner CO_2 compression and injection system

CO_2 injection at Sleipner differs from industry practice because the CO_2 is wet and contaminated with methane. A brief summary of the initial requirements for the design is as follows:

- Materials have to remain resistant to corrosion and sulphide stress cracking throughout their required length of service. The low temperature requirement for CO_2-bearing equipment is generally -60 °C.
- The system should be able capable of storing up to 1.7 MSm^3/d CO_2 and handling a variable injection rate.
- The system should not require the constant addition of corrosion inhibitors during CO_2 injection.

The desired CO_2 injection system is obviously one that operates at pressures and temperatures beyond the hydrate formation envelope (dense phase CO_2 injection). A sketch of the CO_2 compression system is shown in Figure 4. The CO_2 passes through four compression stages, each of which removes water at temperatures 20-30 °C. For gaseous CO_2, the ability to dissolve water is lower at the third stage pressure of 32 bar than at the wellhead pressure of ~65 bar. This is to counter the formation of hydrates. The compressor outlet pressure is controlled by the duty of the cooler (temperature control to obtain right density), which must be adjusted according to wellhead pressure fluctuations and independent of the injection rate.

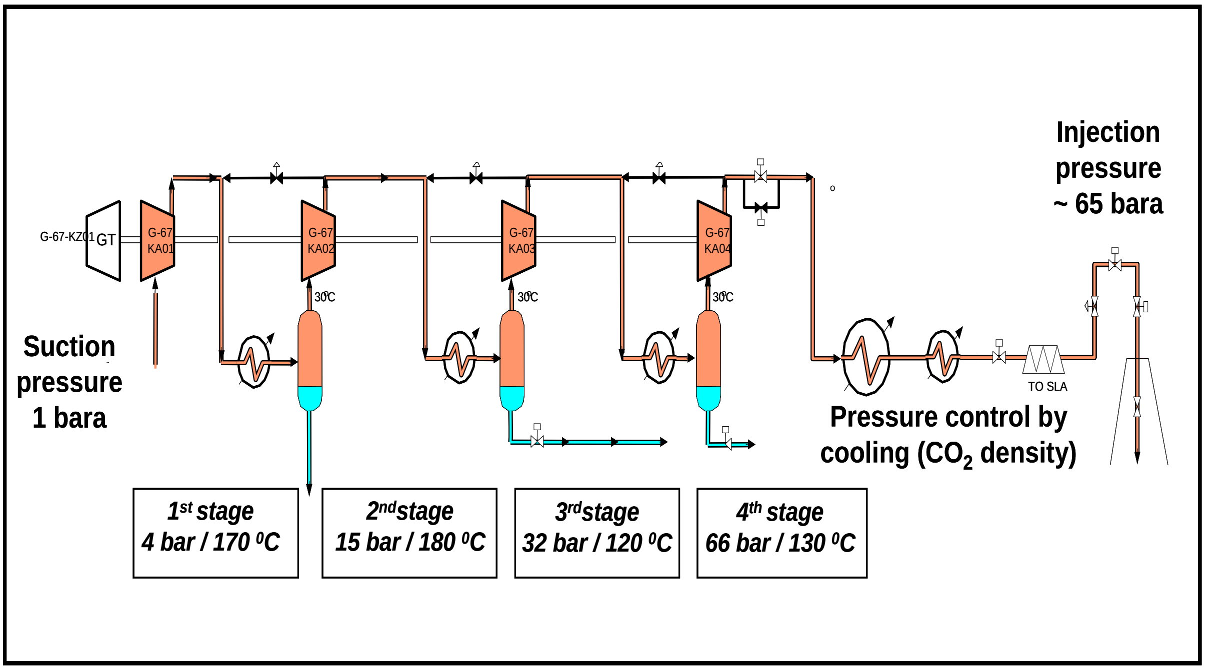

Figure 4. An illustration of the Sleipner CO_2 compression system

4. Conclusions

The development of the Sleipner West gas/condensate field with its high CO_2 content (9 mole%) has been made possible without causing substantial environmental pollution.

The CO_2 gas is extracted using an amine plant installed on the SLT platform. The CO_2 content in the natural gas has been reduced to 3 mole%, which is slightly above the 2.5 mole% gas sales specifications. This excess can be either overcome through injection (into the Sleipner East Ty Field) or by blending (at the SLR platform). The amine plant has been continually upgraded during the fields production history, and the operational costs have been considerably reduced, from about NOK 50 to 5 million (USD 7.5 to 0.75 million).

The CO_2 gas passes through a four stages compression system and cooler, which ensures that the CO_2 is in the dense-phase region. It can therefore be adjusted for fluctuations in wellhead pressure and thereby be independent of the injection rates.

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