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SLEIPNER VEST CO_2 DISPOSAL, CO_2 INJECTION INTO A SHALLOW UNDERGROUND AQUIFER

Alan Baklid and Ragnhild Korbøl, STATOIL, Geir Owren, SINTEF

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Abstract

This paper describes the problem of disposing large amounts of CO_2 into a shallow underground aquifer from an offshore location in the North Sea. The solutions presented is an alternative for CO_2 emitting industries in addressing the growing concern for the environmental impact from such activities. The topside injection facilities, the well and reservoir aspects are discussed as well as the considerations made during establishing the design basis and the solutions chosen. The CO_2 injection issues in this project differs from industry practice in that the CO_2 is wet and contaminated with methane, and further, because of the shallow depth, the total pressure resistance in the system is not sufficient for the CO_2 to naturally stay in the dense phase region. To allow for safe and cost effective handling of the CO_2, it was necessary to develop an injection system that gave a constant back pressure from the well corresponding to the output pressure from the compressor, and being independent of the injection rate. This is accomplished by selecting a high injectivity sand formation, completing the well with a large bore, and regulating the dense phase CO_2 temperature and thus the density of the fluid in order to account for the variations in back pressure from the well.

Introduction

The Sleipner fields are located in the Norwegian sector of the North Sea, approximately 250 km from the coastline. The production licenses that cover the fields are owned by Statoil, Esso, Norsk Hydro, Elf and Total and is operated by Statoil. The main reserves in the area consists of the gas/condensate in the Sleipner Øst and Vest Fields, ref. fig 1. The Sleipner Øst Field contained initially 64 GSm^3 rich gas and is produced with partial reinjection of produced gas. The Sleipner Øst Field is developed with a fully integrated platform (Sleipner A) which provides drilling and process facilities as well as living accommodations. Sleipner Øst commenced contractual deliveries under the Troll Gas Sales Agreements October 1993.

References, tables and figures at end of paper

The Sleipner Vest Field contains 202 GSm^3 rich gas The reservoir is fairly faulted with different pressure regimes and different fluid properties in different fault blocks. The CO_2 content varies between 4 - 9.5 %. The field is developed by pressure depletion with 18 production wells. The wells are drilled from a wellhead platform (Sleipner B) located on the central part of the Sleipner Vest Field itself, and from a subsea template in the northern part of the field. The Sleipner Vest Field will be produced at a plateau rate of 20.5 MSm^3 sales gas per day. All produced gas will be transported untreated from the wellhead platform through a 12 km long pipeline to a process and treatment platform (Sleipner T) located next to and bridge connected to the Sleipner A platform, fig. 2. Planned production start is August 1996, and the production period is estimated to year 2022. The existing pipelines will be used for transport of petroleum products. The Sleipner Vest gas will also be delivered under the Troll Gas Sales Agreements. These agreements set a sales specification of maximum 2.5 % by volume CO_2 in the sales gas delivered to the pipeline. To meet this specification the CO_2 has to be removed at the field. The CO_2 will be removed using an activated amine.

During the early planning of the field development, increased environmental concern raised the question of an alternative to atmospheric release of the CO_2. Releasing this amount of CO_2, approximately 1 million metric ton per year or cumulative 20 million metric tons through the life time of the field, would represent a 3 % increase in the total Norwegian CO_2 emissions to the atmosphere. As a key element in an overall effort to limit the total discharge of combustion gasses and CO_2 to the atmosphere from the Sleipner Vest development, the owners of the production license decided not to dispose the produced CO_2 to the atmosphere.

Disposal alternatives

Several alternatives for CO_2 disposal were investigated during 1990 and 1991. One alternative was to export the CO_2 to an oil field in the area for increased oil recovery purpose. Evaluation of possible oil fields showed that the required offtake of CO_2 from Sleipner Vest and the possible injection rate for the candidate oil fields were impossible to match. Injection of CO_2 into an oil field was not considered as a full solution for the Sleipner CO_2 problem.

All the remaining alternatives were based on injection into the underground from the Sleipner A platform. Positioned adjacent to Sleipner T, and having available well slots for injection wells, this platform was found to be best suited for CO_2 injection. One of the alternatives was to inject the CO_2 into the main Sleipner Øst gas/condensate reservoir, the Heimdal Formation, for improved condensate recovery. It was already planned to do gas recycling in the reservoir to increase condensate recovery, and the CO_2 could possibly replace some of the hydrocarbon gas in this recycling. An other alternative was to inject CO_2 into the aquifer of the Heimdal Formation, then primarily to dispose the CO_2. Both the injection alternatives in the Heimdal Formation incurs the risk of contaminating the gas/condensate production from the reservoir. Breakthrough of CO_2 gas in the production wells, would require CO_2 removal also for the Sleipner Øst gas. Injection into the Heimdal gas cap or aquifer would then transfer the CO_2 problem to Sleipner Øst. None of these solutions were considered adequate.

This left the opportunity for injection of CO_2 into a separate aquifer underlying the Sleipner A platform. Two possible formations were identified. These were the Utsira Formation at approximately 800 m depth, and the Skagerrak Formation at about 2500 m depth. The Utsira Formation has been chosen because of its shallow depth and lower well and top side costs, its large extension that guarantees necessary volume capacity and its excellent sandstone quality that gives high injectivity. The disadvantages of the Utsira Formation could be unconsolidated rock and subcritical conditions for the CO_2. Neither of these were considered to be of major importance. In addition the Skagerrak Formation is juxtaposed to the gas-condensate reservoir in the Hugin Formation at Sleipner Øst, and the possibility for communication between the two incurs a risk for contamination.

The Utsira Formation

The Utsira Formation is a sandstone formation of Tertiary age, found in the Viking Graben area. The formation consists of fine grained, high permeability, homogenous sand with microfossile fragments, deposed on a shallow marine shelf. In the Sleipner area the top of the formation is located at approximately 800 m true vertical depth. The thickness of the formation varies between 150 to 250 m. The petrophysical properties of the formation is shown in table 1. The formation is water filled and the pressure is hydrostatic. The Utsira sand is overlaid by thick Hordaland shale. This shale is impermeable and widely distributed and will thus function as a barrier hindering the CO_2 to leak back out to the atmosphere.

Pressure, bar	80 - 110
Temperature, degC	37
Permeability, D	1 - 8
Porosity, %	35 - 40
Net sand, %	80 - 100

Table 1, petrophysical properties of the Utsira Formation.

Reservoir Simulations

When the Utsira Formation was selected as a target for the CO_2 injection and disposal, a simulation study was carried out based on the structural contour map of the Utsira Formation. The objective of the study was to investigate how the CO_2 would be distributed in the Utsira Formation. Also the possibility of CO_2 accumulation beneath the Sleipner A platform, where the production and injection wells to the Sleipner Øst Field penetrate the Utsira Formation, was investigated. The Eclipse simulation program was used to construct a 3 dimensional simulation model. As this is a "black oil" type simulator, a 3 phase gas-oil description was used to simulate CO_2 and water. "Gas" in the model was specified with CO_2 properties and "oil" was specified as water. This was necessary to describe the solubility of CO_2 in water. The solubility of CO_2 in water increases with increased pressure, from 28 Sm^3/Sm^3 at 70 bar to 31.4 Sm^3/Sm^3 at 125 bar. A seven layer model with 28 by 27 grid blocks was constructed with a grid block size of 250 by 250 m in the area of expected CO_2 distribution. The total pore volume of the model was approximately 660 times the total injected CO_2 volume. Injection volume was 1.7 MSm^3 CO_2 per day for 20 years.

The simulation focused mainly on areal an vertical distribution of CO_2 during the 20 years of planned injection. Both the vertical location of perforation interval in the 250 m thick formation and the effect of sub- versus supercritical conditions for CO_2 were studied. The following are the main results from the study:

- The CO_2 should be injected at the bottom of the formation to minimize the areal distribution and maximize the amount dissolved in water.

- The maximum extension of CO_2 after 20 years of injection was 3 km in any direction.
- There were no major differences in areal distribution between free and dissolved CO_2.
- Supercritical conditions resulted in a larger distribution of free CO_2.
- Up to 18 % of the CO_2 injected was dissolved in the formation water.
- An increase in the reservoir pressure of 30 bar close to the injection point should be expected.

The injection well, to scale, with CO2 distribution after 20 years is shown in fig. 8.

Design basis

This is the first time CO_2 is disposed into underground. To this date all CO_2 injection projects reported have been motivated by increased oil recovery. To the authors knowledge, it is also the first time CO_2 is injected into the underground from an offshore location. A design basis for the disposal system had to be developed and is summarized as follows:

- The requirement for the injection system is to be able to dispose the amount of CO_2, up to 1.7 MSm^3 CO_2 per day, produced at any time. The amount vary as per changes in production rate, depending on the pipeline offtake of gas, and also because of the differences in CO_2 content in the various segments of the Sleipner Vest hydrocarbon reservoir. Since a service life of 25 years is required, the system must be designed to allow for increasing pressure resistance resulting from charging the formation.
- On an offshore location the inherent space and weight limitations results in several compromises in terms of the extent processing can be done adequately. The CO_2 received from the process is supersaturated with water with a pH of 3.0 and contains up to 150 ppm H_2S. There are, however, no dissolved oxygen present. The material selection for the CO_2 containing equipment have to account for the above conditions in terms of corrosion resistance through the required service life and as well, resistance to sulphide stress cracking. The CO_2 is contaminated with up to 5 % non-condensable gases.
- The requirements for robustness and built-in safety in the system are strict on an offshore location. Because of its nature, leaking CO_2 that forms dry ice could potentially cause low temperature damage to vital parts of the weight bearing structure of the installation, not designed to remain ductile at low temperatures. Solid state CO_2 at atmospheric conditions reach -79 degC. A blowdown study showed that due to heat transfer from surrounding environment, the general low temperature requirement for CO_2 containing equipment can be set at -60 degC.
- Since the drilling rig is demobilized after an initial period of the field life, the well system is required to not need any major workover during the field life, thus the solutions chosen had to provide the robustness and flexibility to solve potential problems as loss of injectivity, and thereby need for reperforation or other remedial activities, without the need for a rig.
- In order to avoid damage to the production wells nearby penetrating the Utsira Formation, the injection point in the formation needed to be sufficiently far away. Studies indicate this point to be some 3 km away from the other wells.
- The Utsira Formation is situated 800 m below the seabed. The reservoir properties allows for high injectivity with a permeability in the range of Darcies. This will cause the CO_2 to enter the two-phase region during static equilibrium and possibly also on low injection rates. The water and methane impurities in the CO_2, may lead to formation of hydrates if the fluid need to be choked back. There is a requirement for the system not to need injection of inhibitors during injection at any steady state rate.

Injection concepts

Several solutions that would possibly satisfy the requirements could be visualized. Figure 3 is showing bottom hole pressure versus wellhead pressure relationship for pure CO_2 in the well. The diagram reflects the static head in the tubing. As the Utsira Formation is at a low depth, the bottom hole pressure at the perforations is only about 110 bar. For this discussion, it can be assumed that plateau injection rate results in friction pressures in the well and the formation in the range of 15 bar. Injection of CO_2 as a liquid would be favorable in terms of equipment investment and energy consumption since this would require the lowest wellhead pressure. The thermodynamic properties of the CO_2, however, have to be taken into account. The fact that the CO_2 can not be regarded as dry in all circumstances results in a low operational margin temperaturewise against formation of hydrates. The non-condensable gas content is not expected to increase above 3 % during normal operation. Even though 5 % was stated as design basis, it would be acceptable to run with inhibition during such periods as they would be rare. The non-condensable gas concentration affect condensation temperature as shown in fig. 5. At a 3 % methane fraction, the condensation temperature is 16 degC as opposed to 22 degC with pure CO_2, both at 60 bar. The methane content also increases the hydrate formation temperature by 1.5 degC to 13 degC at 60 bar, ref. fig. 4. These conditions limit the temperature at which the CO_2 may be condensed, and also to what extent the CO_2 could be sub-cooled to in order to create an operational margin against hydrate formation. Under these circumstances it would be natural to consider dehydration of the CO_2. High costs associated with the installation of necessary equipment prevented this from being a primary alternative.

As can be derived from figure 3, the CO_2 could be injected as a liquid, as gas and liquid two-phase or as a dense (supercritical) fluid. Theoretically, CO_2 gas or partially condensed CO_2, mixed with warm produced water to obtain a suitable hydrostatic column could also be visualized. Due to uncertain availability of produced water which in turn would have to be substituted with seawater made this alternative difficult due to corrosion problems. The three realistic injection scenarios as listed above are examined in the following.

Liquid phase at the wellhead.

Full condensation of CO_2 with the 3 % methane content can not be obtained at pressures lower than 63 bar. At this pressure there is a margin against hydrate formation of 3 degC. The hydrostatic column of liquid CO_2 would be around 90 bar adding to the applied wellhead pressure of 63 bar. The static formation pressure and the dynamic friction pressures in the well and in the formation would correspond to a wellhead pressure of 35 bar with the same hydrostatic head in the well.

Consequently a backpressure device had to be installed. A back pressure valve installed downstream of the condenser prior to entering the well would require inhibitors to be injected to prevent hydrates from forming in the well. The amount necessary was calculated to 1600 liters per hour at a nominal plateau injection rate, and thus not cost effective.

The possibility of moving the back pressure device down in the well was investigated. Then the fluid would be kept in a liquid state until the pressure and temperature was sufficient to allow for the 28 bar differential pressure, across the back pressure device without entering the hydrate region. The downhole chokes used in the industry is a simple device acting as a fixed orifice. A fixed orifice used to choke back 28 bar at a maximum rate, rapidly looses its efficiency when the rate drops below the maximum. Since the injection system need to handle a wide range of injection rates, an adjustable downhole choke is necessary.

Investigation of surface controlled chokes via hydraulic lines and automatically adjustable by means of a spring or nitrogen chamber proved this to be new ground. A development program for the equipment was considered, but was turned down due to the time available and the criticality of the component. It was further found that cavitation was likely to occur and that two or more chokes in series would be necessary.

Two phase flow at the wellhead.

In order to overcome the problem with entering the hydrate region as a result of having to choke back the fluid prior to entering the well, a lighter hydrostatic column could be obtained by partial condensation of the CO_2. Partial condensation to the required gas fraction of approximately 0.25 would be possible at a higher temperature because the methane effect is only significant for condensation of the last 0.10 gas fraction in the CO_2 - methane fluid. 60 bar and 20 degC could be chosen. This improves the operational margin with respect to hydrates. The vapor fraction have to be controlled accurately, ref. fig. 3, in order compensate for the various effects that will occur depending on the injection rate so that the wellhead pressure is always 60 bar. Most pronounced is the effect of liquid hold-up. In the two-phase part of the well, the liquid hold-up will influence the static head. At low injection rate the gas flow rate will be close to zero and the liquid will flow through the stagnant gas. In this case the static head in the two-phase part of the well will be determined by the gas density which is quite low. At higher injection rates there will be no slip i.e. homogeneous flow. The static head will be based on the two-phase density. The diagram showing the wellhead pressure versus bottom hole pressure is based on this assumption. A comprehensive regulation scheme could possibly cater for this effect.

The CO_2 compressor and condenser is installed on the Sleipner T platform (SLT) while the injection into the well is performed on the Sleipner A platform (SLA) some 300 m away. The pipeline routing from SLT to SLA contains several inclinations up and down. It is possible to transport the CO_2 in two-phase flow from SLT to SLA at a temperature above the hydrate formation temperature. The static head in the well is governed by the average vapor fraction in the well. This vapor fraction is controlled by regulating the duty of the CO_2 condenser. This control will be slow due to the transport time from SLT to SLA. The transport time is increasing with decreasing rates. At low rates the control will be disturbed by geometry induced slugging in the pipeline between the two platforms. It is therefore reason to believe that duty control of the condenser would be difficult, specially at low rates. Pressure fluctuations could result in compressor trips. Moving the CO_2 condenser to SLA and installing a sloped line to the well would address the problems of slugging. This meant, however, additional expensive installation work on SLA, not catered for in terms of space and project schedule, and would only partly address the uncertainties with this solution.

Alternatively, the CO_2 can be transported from SLT to SLA in two separate pipes, one for liquid phase, and one for the vapor phase. In this case the condenser is operated as a total condenser producing the liquid phase while the gas phase are taken downstream of the compressor aftercooler. The liquid and gas phase would be mixed at SLA just before the fluid enter the well where the right vapor fraction in the injection stream was obtained by flow controllers on the two pipes. Dynamic simulations of the fluid flow and the control system was performed with the OTISS model of the injection system. The simulations showed that sufficient controllability could be obtained.

Since the condenser operates with total condensation, this solution suffer from the same narrow operational margins with respect to hydrate formation as the case of liquid CO_2 injection.

Dense (supercritical) phase at the wellhead.

The problems with the concepts described above are related to formation of hydrates and complicated process control. The only viable solution seems to be a system which naturally operate at pressures and temperatures outside the hydrate formation envelope. The CO_2 may be compressed to 80 bar and cooled to about 40 degC at the wellhead, ref. fig. 3). This would be in a supercritical state. In this region the density of the CO_2 is strongly temperature dependent, ref. fig. 6. These properties can be used to create a hydrostatic column in the well so that the injection wellhead pressure at all times are above the critical point. The temperature must be controlled to obtain the right density of the injection stream to allow for a constant wellhead pressure independent of injection rate. The cooler duty would need to be controlled by the injection wellhead pressure.

For each compression stage, water is knocked out at 30 degC. For the gaseous CO_2, the ability to dissolve water is lower at the third stage pressure of 32 bar than at the wellhead pressure of 80 bar. This ensures robustness with respect to hydrate formation and would also permit some choking of the CO_2 should that become necessary in start-up situations. One could take advantage of the water solubility effect when judging the corrosivity of the fluid during normal operation. Due to the criticality of this one well and the risk for carry over when production is maximized that has not been done.

At prolonged shut-in periods, the temperature at the top part of the well may drop to 5 degC and a pressure of 40 bar which is within the hydrate formation area. Hydrate inhibition of the well will be required in this case.

The injection system is self-adjusting to some extent. A drop in injection rate would result in a lower in wellhead pressure, leading to a lower density of the CO_2 in the well, resulting in a lighter hydrostatic column and higher wellhead pressure and vice versa. This effect would not be sufficient to ensure that the wellhead pressure remains constant in the wide range of injection rates which is required. Therefore the cooler capacity must adjust according to wellhead pressure fluctuations.

In normal operation, the compressor speed is controlled by the suction pressure. All CO_2 which is separated out in the amine plant have to be taken over by the injection system. The compressor outlet pressure is controlled by the duty of the cooler. At a lower limit of the injection rate, the anti-surge control of the CO_2 compressor becomes active. Now the compressor control will regulate the outlet pressure. This may be in conflict with the cooler control which is based on wellhead pressure. This conflict is minimized since the cooler control is much slower than the anti-surge. In order to avoid running with active anti-surge, two sets of impellers have been planned for.

From fig. 3 it can be seen that with a 80 bar nominal output compressor, i.e. 80 bar wellhead pressure, the system is able to address increasing bottomhole pressure up to 170 bar resulting out of local charging of the formation or loss of injectivity due to near wellbore effects. This corresponds to a cooling temperature of 20 degC which have been designed for. Should reperforation higher up in the well become necessary, the system will handle the lower bottom hole pressure by simply increasing the temperature of the injection stream.

Well design

Based on the requirements given in the design basis it was necessary to plan for a shallow long reach well, departing at least 3000m from the drillcenter. A special casing program was selected, including 18 5/8" x 13 3/8" surface casing down to 585 m measured depth with an inclination built to 30 degrees. A 10 3/4" x 9 5/8" production casing into top Utsira Formation at 2387 m measured depth, 996 m vertical depth, with inclination built to the sail angle of 83 degrees. A 7" liner was run in a 8 1/2" hole drilled to a total depth of 3752 m measured depth which is 1163 m vertically, all referred to the rotary table. Cementing the 2600 m long liner section including the liner lap was accomplished by using low-rheology mud and cement in order to avoid lost circulation and improper cement isolation in the liner lap.

A 7" monobore design was chosen in order to satisfy the requirement for low friction pressure loss and thereby low rate dependency for the system as a whole. This also ensures good access for remedial actions in this important well. The high sail angle of the well results in an injection point with necessary distance to the other wells, but also gives the flexibility to reperforate should that become necessary. 100 m of perforations were necessary to obtain the injectivity corresponding to 100 m^3/day/bar of water. According to the reservoir simulations, the CO_2 front will not reach back to the regular production wells, which have, however, been equipped with 13 % chrome casing joints through the Utsira Formation. The completion components in this well consist of a liner hanger with seal bore receptacle for mating with the seal sub on the tubing end, a packer for barrier purpose to annulus, an expansion joint to allow for travel due to temperature, a downhole fail-safe close safety valve with surface control, and an injection sub for methanol injection in the top part of the well. The wellhead and christmas tree is of standard offshore layout with provision for methanol injection through the upper block cross.

Material selection

In order to give the necessary service life, solution annealed 25 % Cr duplex stainless steel has been chosen for the tubulars used as injection tubing and the exposed parts of the 9 5/8" casing. 22 % Cr duplex steel have been used in the topside equipment since 65 ksi SMYS was acceptable. Assessment of the fluid corrosivity concluded that the present water which is mainly condensed water with a pH of 3, would produce an acidic water film wetting the metal surfaces. The design H_2S concentration of 150 ppm, corresponding to partial pressure of 0.20 bar combined with the low pH, required sulphide stress cracking to be considered in the material design. No consideration was placed upon dissolved oxygen as the topside process has been purposely designed to avoid oxygen ingress into the injection fluid during normal operation. Only high alloy metallurgy was considered reliable for the long term exposure in question, specially since the project rely on a single well. The corrosion testing assumed water wetted surfaces with fluid characteristics as mentioned under the design basis section. The sulphide stress cracking testing was performed as per NACE Standard Method A and D, and Slow Strain rate Tensile Testing. The material candidates tested were several of the regular martensitic steels and 25 % Cr duplex steel. It was concluded that the martensitic grades gave variable results, and that the best suited material for this duty is solution annealed 25 % Cr duplex steel. For machined components Inconel 718 and Incoloy 925 have been chosen. Nitrile elastomers are used. The subsea safety valve is of a non-elastomeric type with metal to metal seal. The christmas tree is in ASTM A182 Grade F22, fully cladded with Inconel 625.

Because of the nature of the injected CO_2 fluid, any leak with a resulting pressure drop can potentially cause localized freezing and the formation of ice. This can reduce the temperature of a component locally to approximately -60 degC which could produce a potentially brittle fracture problem at the top of the well. Charpy 'V' toughness data shows satisfactory low temperature behavior of the chosen materials. The stem packings on the christmas tree is made of an engineered plastic. Low temperature tests performed proved that functional and pressure integrity was retained. In order to avoid freezing of the annulus, a $CaBr_2$ brine with a freezing point of -46 degC is used as a packer fluid.

Conclusions

A large offshore gas-condensate field, containing up to 9 % CO_2 is developed offshore Norway. It was decided not to let out the CO_2 to the atmosphere.

A shallow sand formation was identified to suit the needs for safe and permanent disposal of the CO_2. The movement and distribution of the injected CO_2 resulting out of 20 years of injection have been simulated. One well with necessary departure from other wells were drilled to provide the conduit to the injection point in this formation.

A CO_2 disposal system with ability to dispose the amount of CO_2 produced at any time has been found. In the search for the best combination of safe and robust handling, cost-effectiveness, and simplicity in terms of operation, several alternative injection concepts were examined. The solution to best satisfy the objectives with the various constraints found, proved to be a system based on dense phase CO_2 injection.

The key factors resulting in additional considerations over what is usually associated with the improved recovery projects were

- the shallow depth and low injection pressure
- the wet CO_2
- the need for the system to dispose what is available of CO_2 at any time

Assessment of the corrosivity resulted in the selection of CRA materials for injection system including the well, in order to provide the necessary confidence in the long term service required.

Acknowledgment

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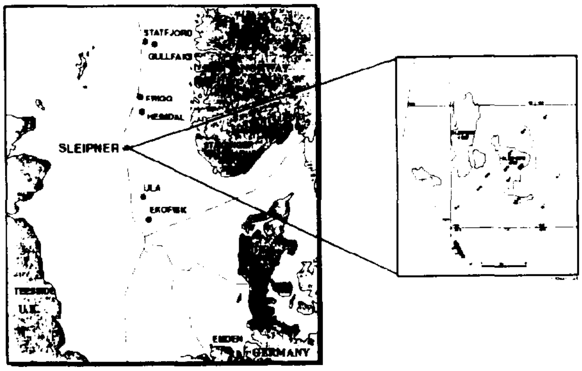

Fig. 1. Sleipner area

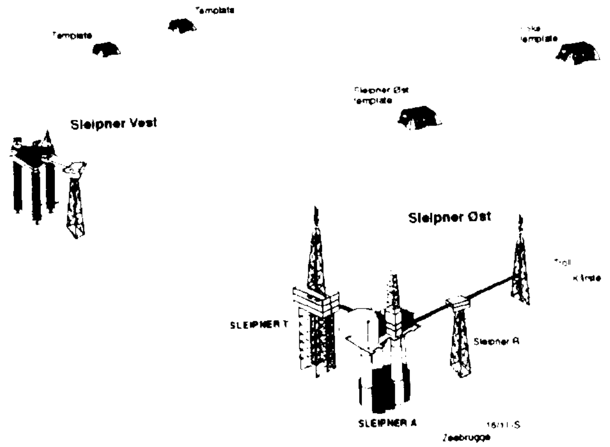

Fig. 2. Field installations

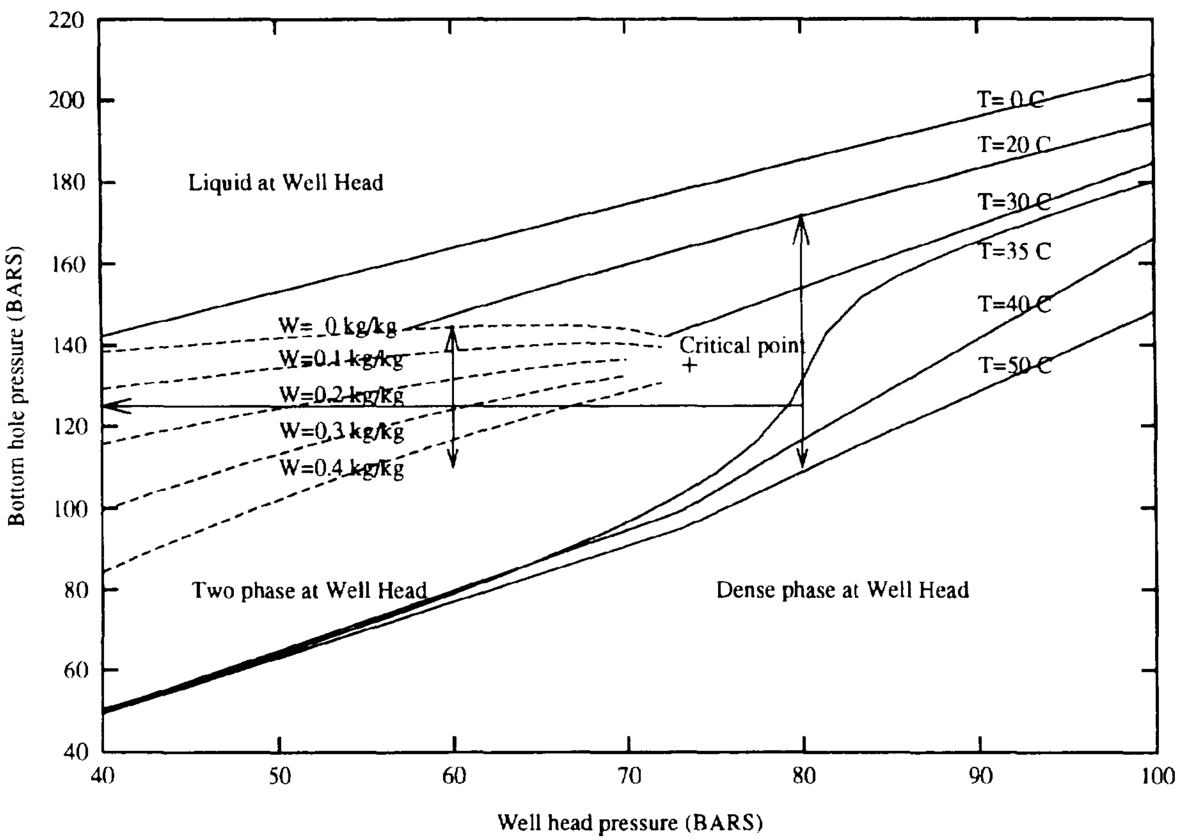

Fig. 3. Bottom hole pressure versus well head pressure for pure carbondioxide as function of well head temperature or vapour fraction. The two-phase calculations are based on no-slip conditions. Pressure loss in tubing and injection is not acoounted for. Calculations are based on well depth 1100 m.

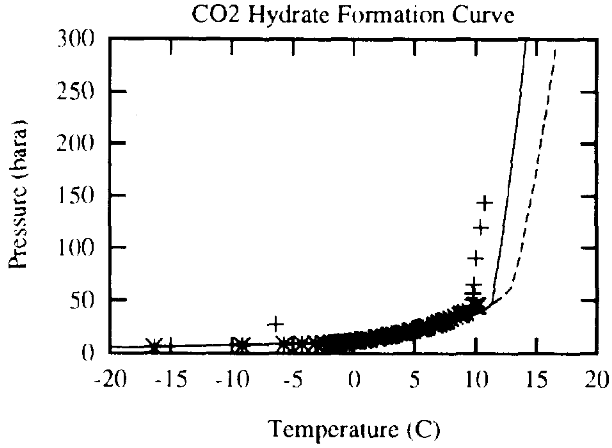

Fig. 4. Hydrate equilibrium curve for cabondioxide hydrates calculated with the computer program HYDFLS from Calsep. Experimental data cited on the diagram. Hydrate equilibrium line for carbondioxide with 5% methane is also drawn.

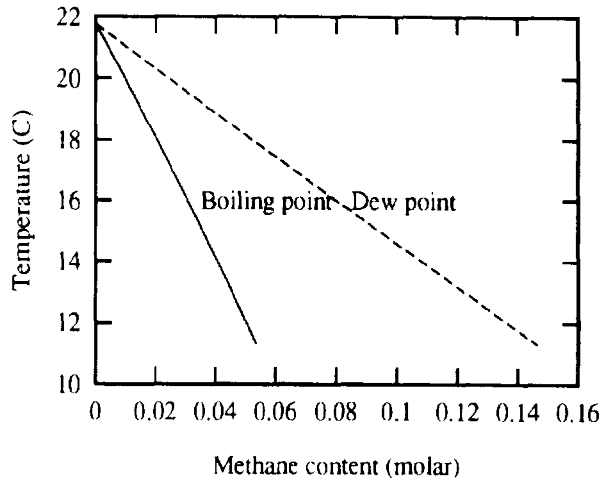

Fig. 5. Dew and bubble point temperature for carbondioxide -- methane at 60 bar.

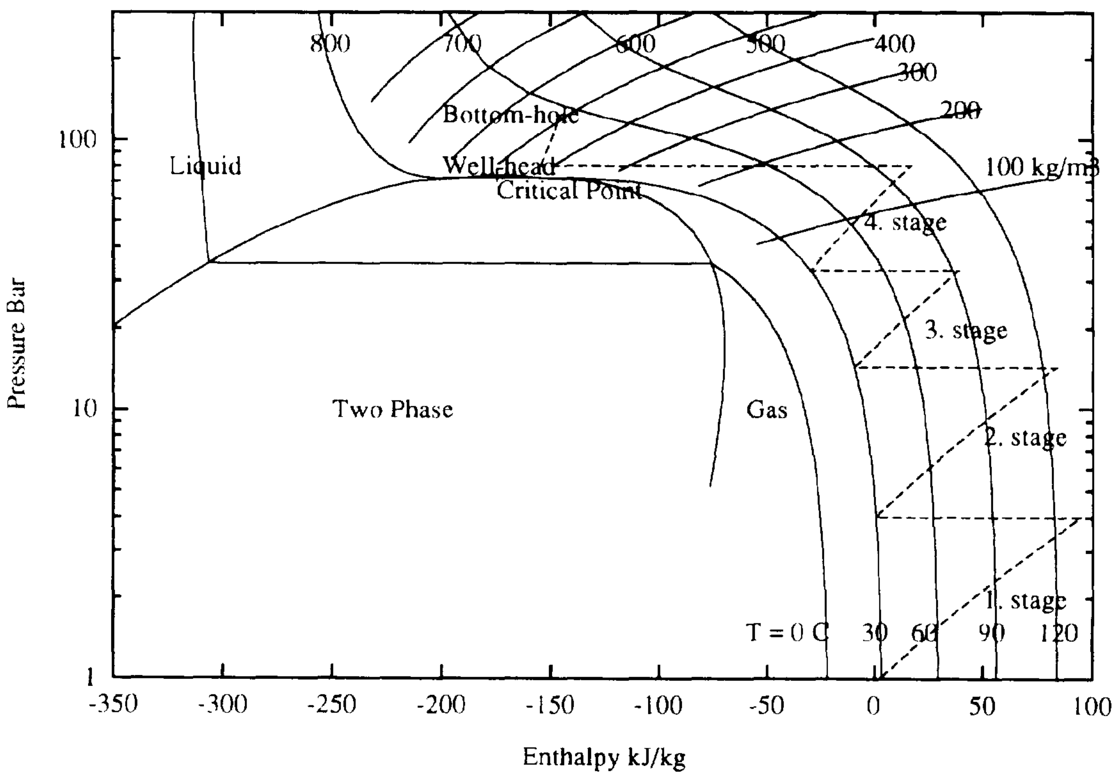

Fig. 6. Enthalpy - pressure diagram showing the carbondioxide compression and injection into the well.

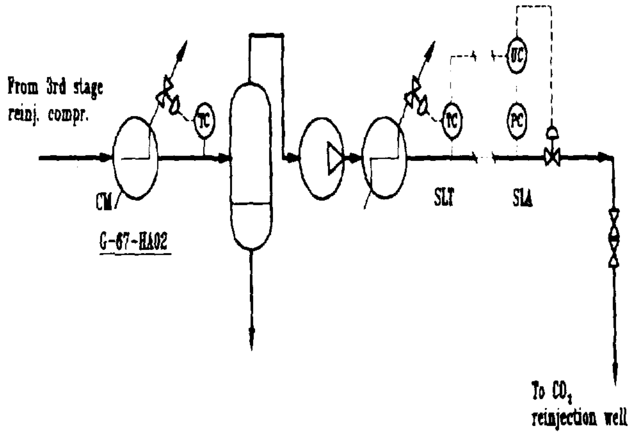

Fig. 7. Process and intstrumentation diagram for dense phase injection showing the pressure control of the cooler.

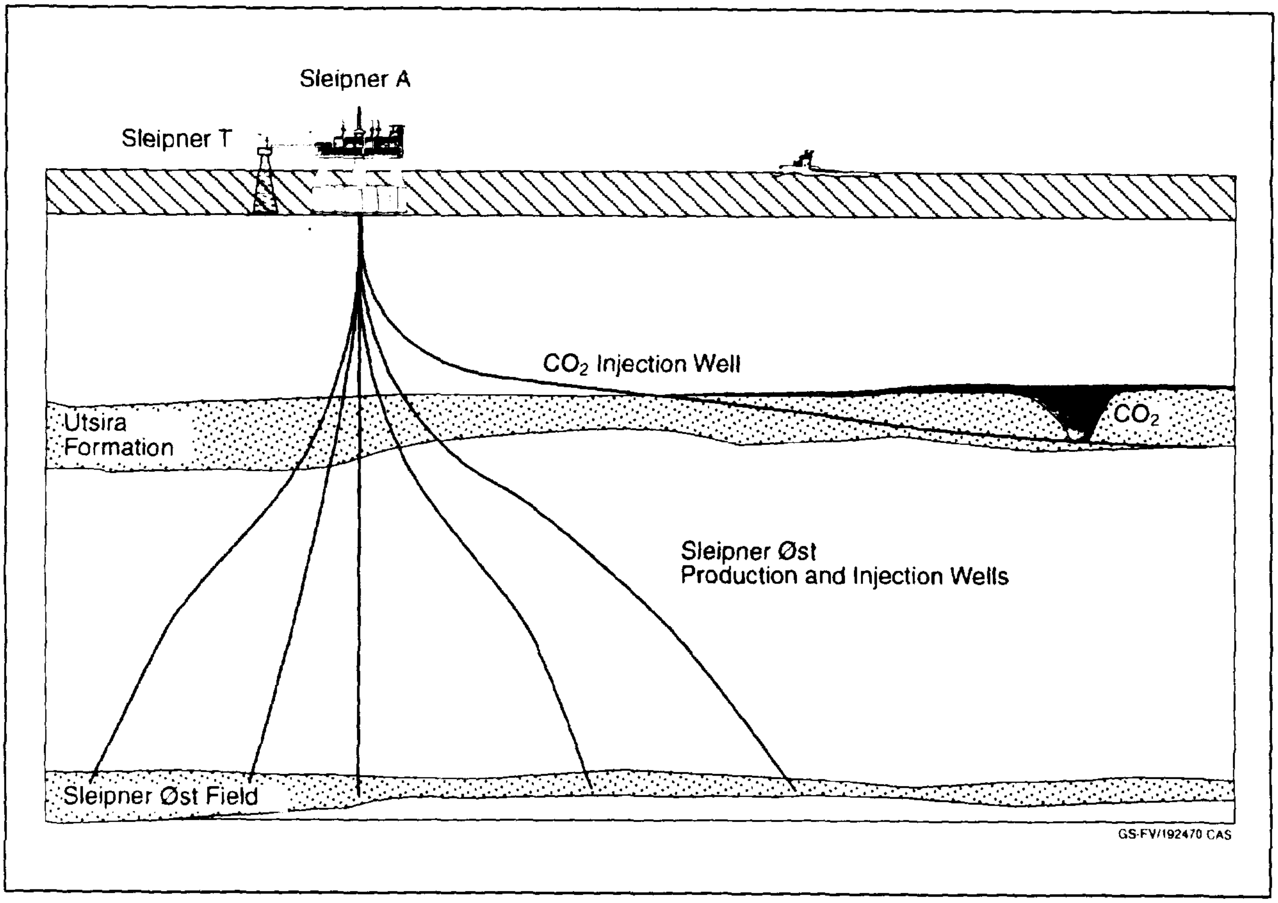

Fig. 8. Regular production wells in Heimdal, CO_2 well in Utsira, CO_2 distribution after 20 years of injection.