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Injection of CO_2 at ambient temperature conditions – Pressure and temperature results of the "cold injection" experiment at the Ketzin pilot site

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Abstract

From June 2008 to August 2013, slightly more than 67 kt of CO_2 were injected at the Ketzin pilot site (Brandenburg, Germany). The CO_2 reservoir is a saline aquifer at a depth of 630 - 650 m with initial pressure and temperature conditions of about 33 °C/62 bar. These reservoir conditions are near the critical point of pure CO_2 (31.0 °C/73.8 bar) and the CO_2 liquid-vapour equilibrium. In order to avoid phase transitions and near-critical phenomena throughout the injection process the CO_2, which was delivered by road tankers and stored in intermediate storage tanks on site at ~ -18 °C/21 bar, was pre-conditioned at site and pressurised to ~ 65 bar and heated to ~ 40 °C during regular operation. This injection process design worked exceptionally well. However, such a pre-conditioning and heating of the injected CO_2 to elevated temperature is unrealistic for an industrial sized CO_2 storage setting as the energy need is high and costly and the CO_2 will be delivered by pipeline already at ambient temperature. To study the effects of lower pre-conditioning temperature and effects of potential two-phase flow on the injection process, a "cold injection" experiment was carried out between March and July 2013. The injection wellhead temperature was decreased stepwise from 40 °C down to 10 °C. Below 20 °C two-phase flow developed in the surface installations and in the injection well down to the reservoir and a mixture of gaseous and liquid CO_2 has been injected. This two-phase CO_2 injection ran smoothly for eight weeks without any operational issues.

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Keywords: CO_2 storage, CO_2 phase behaviour, injection, saline aquifer, pilot site, Ketzin

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1. Introduction

Among other measures, storage of CO_2 in geological formations is needed to meet the goal of limiting the global warming to a maximum of 2 °C above pre-industrial level [1]. To investigate operational and scientific issues of geological storage of CO_2, the GFZ German Research Centre for Geosciences has set up a unique research infrastructure near the town of Ketzin in the Federal State of Brandenburg, Germany [2-5]. Between June 2008 and August 2013, slightly more than 67 kt of CO_2 have been stored in a saline aquifer located at 630 m to 650 m depth. Hence, the Ketzin project represents valuable experience in operating a CO_2 storage site [6]. Since end of August 2013, the Ketzin pilot site has reached its post-closure phase [7].

The foci of the work carried out at the Ketzin pilot site are monitoring of the CO_2 plume in the storage formation and proof of site conformance, increase knowledge on operational issues and to study the complete life-cycle of a storage site at research scale. The CO_2 for the injection had to be bought off the market since no reliable source of captured CO_2 from power plants or sources alike was available during the injection period. Therefore the CO_2 was mainly of food grade quality (purity > 99.9%). In May and June 2011, approximately 1,500 tons of captured CO_2 from the pilot capture facility at "Schwarze Pumpe" (Germany) were injected (power plant CO_2 with a purity > 99.7%) and in July and August 2013 the injection of a synthetic mixture of 95% CO_2 and 5% N_2 was successfully tested [8].

The CO_2 was generally delivered by road transportation to the Ketzin site and stored on-site in intermediate storage tanks in liquid state at about -18 °C/21 bar with a corresponding density of about 1,020 kg/m^3. Due to the shallow reservoir, the initial reservoir conditions have been approximately 33 °C/62 bar. As a consequence of the injection process the reservoir pressure rose to a range between 68 and 78 bar [6]. At these conditions CO_2 has a density of about 250 to 400 kg/m^3 and injecting the CO_2 without any pre-conditioning at site would have resulted in an about three-time increase in volume within the reservoir. At the same time these reservoir conditions are near to the critical point of pure CO_2 (31.0 °C/73.8 bar) and the CO_2 liquid-vapour equilibrium. This raised the probability of phase transitions and near-critical phenomena in the surface injection installations, within the injection well and also within the reservoir. In order to avoid phase transition, large density changes and their unwanted side-effects, the CO_2 was pre-conditioned, heated and vaporized on site during regular operation before it was injected into the subsurface. Typical wellhead injection temperatures during regular operation ranged between 35 and 45 °C. However, such a pre-conditioning and heating of the injected CO_2 is far from being realistic for an industrial sized CO_2 storage setting [10,11]: i) The CO_2 in full scale CCS applications will be captured at large point sources and compressed and transported via pipelines to a suitable storage site. Thus, the temperature of the CO_2 at the injection point will likely be lower than in the Ketzin project and correspond to the respective ambient temperature. ii) Any pre-heating of the CO_2 before injection will significantly raise the injection costs and therefore provides an economic barrier.

To study more realistic injection conditions, demonstrate the feasibility of CO_2 injection at a temperature level to be expected for an onshore storage scenario, and test the effects of two-phase flow within the surface injection installations and the injection well, an ambient temperature injection experiment ("cold injection") was performed at the Ketzin site between March and July 2013. The targeted final wellhead injection temperature for the "cold injection" experiment was 10 °C, which represents a reasonable value for a pipeline CO_2 transport scenario. This contribution presents operational aspects including pressure, temperature and flow rate data of this cold injection experiment.

2. Regular injection operation at the Ketzin site

The whole injection process is pressure driven and the minimum bottom hole injection pressure is jointly defined by the reservoir properties, which are dictated by geology, and the chosen injection rate. The actual reservoir pressure less the weight column of the CO_2 in the injection well determines the wellhead pressure and by this the minimum pressure that has to be overcome by the injection facility to allow for injection. Besides adjusting the injection rate, temperature is the only variable that can be externally controlled. The pre-conditioning of the CO_2 during regular injection operation was consequently done in three steps (Fig. 1): To overcome the minimum inflow pressure as dictated by the reservoir, the liquid CO_2 from the intermediate storage tanks has first been pressurised

with plunger pumps (1 to 2 in Fig. 1) without any notable increase in temperature. Pressurising the CO_2 prior to the heating by use of plunger pumps for liquid media ensured a very precisely defined mass flow rate. The following quasi-isobaric heating (2 to 4 in Fig. 1) was done with two separate devices. An ambient air heat exchanger unit raised the temperature from the intermediate storage temperature of about -18 °C to nearly ambient temperatures resulting in an exchanger outlet temperature between slightly above 0 °C during the winter time and > 20 °C during the summer time (2 to 3 in Fig. 1). Final heating and vaporization of the CO_2 was done by an electrical heater and raised the temperature to ensure meeting the targeted injection wellhead temperature (3 to 4 in Fig. 1). Piping of the so pre-conditioned CO_2 from the injection facility to the wellhead via an about 100 m long 1 inch diameter insulated surface pipeline (4 to 5 in Fig. 1) resulted in slight pressure and temperature losses. In-well flow (5 to 7 in Fig. 1) is characterized by continuous pressure increase but cooling in the upper parts of the well and re-heating in the lower parts. The in-well conditions are controlled and monitored by a downhole pressure and temperature fibre-optical sensor at 550 m depth (6 in Fig. 1). This regular injection process resulted in single-phase flow throughout the entire injection installations and in-well and ensured a smooth, reliable and safe injection operation. However, this pre-conditioning required significant energy (~ 66 $kWh_{el.}/t\ CO_2$ as a mean value throughout different injection regimes) for heating up the CO_2.

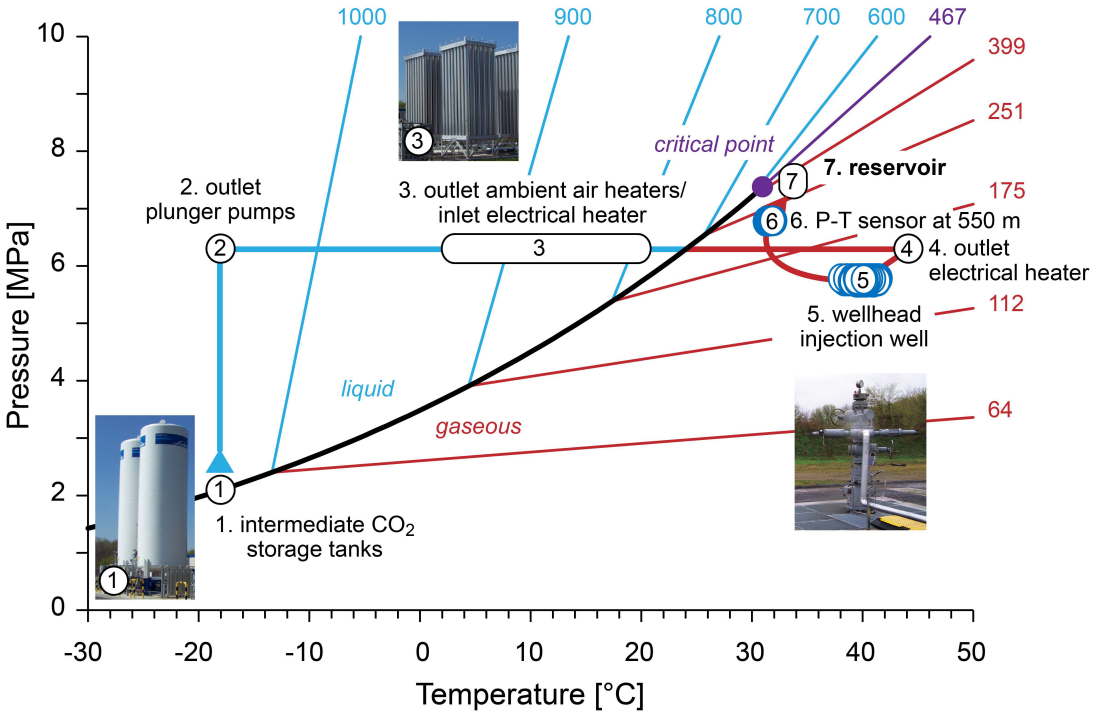

Fig. 1. The injection process at the Ketzin pilot site during regular (e.g. heated) injection and the corresponding pressure and temperature conditions at the key process steps. In addition the liquid/vapour equilibrium for pure CO_2 is shown, terminating at the critical point of pure CO_2. Straight lines starting at the liquid/vapour equilibrium are lines of constant CO_2 density; density values are given in kg/m^3. (see text for details; modified after [9]).

3. Experimental setup and execution

To ensure overall safety during the cold injection experiment the injection temperature was decreased stepwise to control and monitor the effects of each individual temperature step. To monitor the temperature and pressure evolution in the injection installations and within the injection well the following pressure and temperature data have been recorded continuously throughout the entire experiment (details on operational monitoring can be found in [6]):

- temperature in the surface piping about 3 m upstream of the wellhead ("wellhead" temperature in the following)
- wellhead pressure directly at the wellhead
- distributed temperature sensing (DTS) along the injection well with a fibre-optical cable running on the outside of the 3 ½ inch injection tubing and
- downhole pressure and temperature with a fibre-optical sensor at 550 m depth ("bottom hole" pressure and temperature in the following).

The "bottom hole" sensor at 550 m depth is located about 80 m above the top of the reservoir at 630 m. The herein reported "bottom hole" data therefore do not represent "true" reservoir conditions. Depending on the density of the CO_2 between 550 and 630 m depth and therefore the weight-column of the CO_2 the true reservoir pressure is slightly higher than the pressure recorded at 550 m depth. For regular injection operation with pre-conditioned CO_2 and single-phase flow the pressure value at 550 m is about 2 bar lower than the actual reservoir pressure [6]. However, for two-phase flow the average density and therefore weight-column of the injected CO_2 will increase and the pressure difference between reservoir and the sensor at 550 m will likewise increase (see below).

In addition, the flow rate has been measured with a coriolis mass flow measurement device (CMD, flowmeter) installed about 8 m upstream of the wellhead. All bottom hole pressure values are given "as is" from the pressure and temperature sensor at 550 m depth. All values for chosen injection rate and targeted wellhead injection temperature are setpoint values. Prior to the experiment, steady state conditions with respect to wellhead and bottom hole pressure and temperature have been established with an injection rate of 1.5 t/h CO_2 and a targeted wellhead injection temperature of 40 °C; the steady state bottom hole conditions corresponded to around 32 °C and 68 bar (Fig. 2). As changes in injection rate affect injection pressure and by this the density of the injected CO_2, the injection rate has been kept constant at 1.5 t/h throughout the entire experiment and the targeted wellhead injection temperature has been decreased stepwise to 35 °C, 25 °C, 20 °C, 15 °C and finally 10 °C (Table 1). To control the wellhead injection temperature as precisely as possible, the ambient air heat exchanger unit was by-passed during the experiment and heating was only done by the electrical heater. Due to workover operations at the nearby well Ktzi 203 the injection had to be stopped temporarily during step 4 causing a discontinuation within the cold injection experiment. Also the injection at 10°C had to be interrupted due to technical reasons.

Table 1: Overview on the wellhead injection temperature setpoints and duration of the different experimental steps.

Event	Temperature	From Date	To Date
Steady state	*40 °C*		*27.03.2014*
Step 1	35 °C	27.03.2013	03.04.2013
Step 2	25 °C	03.04.2013	10.04.2013
Step 3	20 °C	10.04.2013	17.04.2013
Step 4	15 °C	17.04.2013	22.04.2013
Discontinuance due to workover	*N/A*	*22.04.2013*	*22.05.2013*
Step 4 (continued)	15 °C	22.05.2014	31.05.2013
Step 5	10 °C	31.05.2013	15.06.2013
Discontinuance due to operational reasons	*N/A*	*15.06.2013*	*02.07.2013*
Step 5 (continued)	10 °C	02.07.2013	22.07.2013

4. Observations

The overall injection process ran smoothly throughout the entire cold injection experiment although measured wellhead and bottom hole pressure and temperature fluctuations became more pronounced with decreasing wellhead injection temperature (Fig. 2). Starting with steady state conditions of ~ 32 °C bottom hole temperature, ~ 57 bar wellhead pressure and ~ 68 bar bottom hole pressure for a wellhead injection temperature of 40 °C, decreasing the wellhead injection temperature to 35 °C (step 1) did not have any effects on either bottom hole temperature (~ 32 °C) or wellhead (~ 57 bar) and bottom hole (~ 68 bar) pressures. Further decrease of the wellhead injection temperature to 25 °C (step 2) resulted in first slight decreases in bottom hole temperature to ~ 31.2 °C and wellhead pressure to ~ 56.5 bar. The bottom hole pressure nevertheless stayed constant at ~ 68 bar. Decreasing the wellhead injection temperature to 20 °C during step 3 continues to slightly decrease the bottom hole temperature to ~ 30 °C and the wellhead pressure to ~ 56 bar while the bottom hole pressure still remained at ~ 68 bar. Contrary to steps 2 and 3, which resulted in only slight changes in wellhead pressure and bottom hole temperature at constant bottom hole pressure, reducing the wellhead injection temperature to 15 °C during step 4 is marked by notable drops in wellhead pressure to ~ 49.6 bar, bottom hole temperature to ~ 26 °C and also bottom hole pressure to ~ 66.8 bar. In addition especially the wellhead pressure but to a minor degree also the bottom hole pressure and bottom hole temperature start to show increased fluctuations.

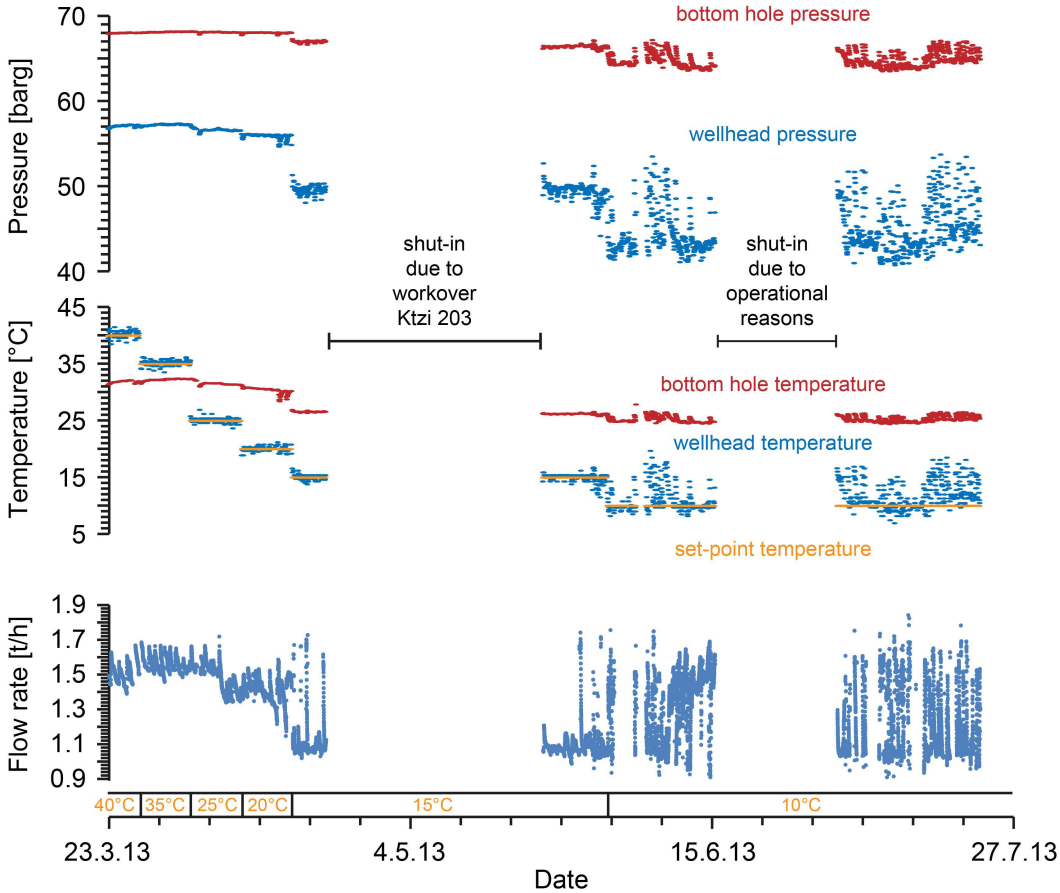

Fig. 2. Overview on all measured parameters during the cold injection experiment

These fluctuations become very prominent during the final step 5 with targeted wellhead injection temperature of 10 °C. The data clearly show that it has been difficult to keep the wellhead injection temperature at a constant level of 10 °C during step 5 of the experiment. While most of the time 10 °C has been realised, there are significant deviations up to over 19 °C and down to 8 °C. These outbursts are undesired side effects due to technical reasons as an automated switch-off has been programmed for wellhead temperatures below 8.5°C and the elevated temperatures are consequently due to excess heat from the re-start process. However, these deviations are mostly only short term events and the data nevertheless allow to draw some general observations: The bottom hole temperature further decreases to ~ 24.5 °C and wellhead and bottom hole pressures markedly drop to ~ 43 and ~ 64 bar, respectively, during step 5.

Although the plunger pumps were run with a constant mass flow of 1.5 t/h throughout the entire cold injection experiment, the flow rates recorded by the coriolis flowmeter show notable fluctuations (Fig. 2). While the fluctuations observed during steps 1 and (partly) 2 are comparable to the flowmeter recordings during regular steady state injection prior to the cold injection experiment they become much more pronounced during steps 3 to 5. During step 4 mean flow rates as recorded by the coriolis flowmeter are ~ 1.08 t/h with several outbursts up to 1.72 t/h. During step 5 the recorded flow rates continuously fluctuate between ~ 0.96 and ~ 1.7 t/h without any clear mean.

The observed changes in wellhead and bottom hole temperature and pressure are consistent with recordings of the distributed temperature sensing DTS along the injection tubing (Fig. 3). During steady state conditions in regular operation, the pre-conditioned and heated CO_2 is notably warmer in the upper part of the well than the surrounding formation and therefore cools down until it approaches the normal background in-well temperature profile at about 300 to 350 m depth. Below about 350 m depth the recorded in-well temperature raises again following the normal background in-well temperature profile. The DTS profiles recorded during steps 2 and 3 show comparable overall behaviour. The DTS profile for step 2 still shows a slight curvature with minor temperature increase in the upper part and more pronounced temperature increase in the lower part of the well, whereas the DTS profile for step 3 displays an almost linear temperature increase with depth. Both profiles, however, approach the normal background in-well temperature profile and the data suggest that all DTS temperature profiles for wellhead injection temperatures ≥ 20 °C follow the normal background in-well temperature profile below 500 m. For wellhead injection temperatures < 20 °C, as exemplified by the DTS profile for step 5 in Fig. 3, the recorded temperature profiles notably deviate from the normal background in-well temperature profile even at depth. The DTS profile for step 5 indicates a linear temperature increase with depth, a lack of dependence upon the normal in-well temperature distribution, and notably lower temperatures than the normal background in-well temperature profile at depth. The temperature differences recorded by DTS at 500 m depth between the individual temperature steps of ΔT = -0.7 °C (regular operation to step 2), ΔT = -1.0 °C (step 2 to step 3), and ΔT = -5.3 °C (step 3 to step 5) agree well with those recorded by the P/T sensor at 550 m depth.

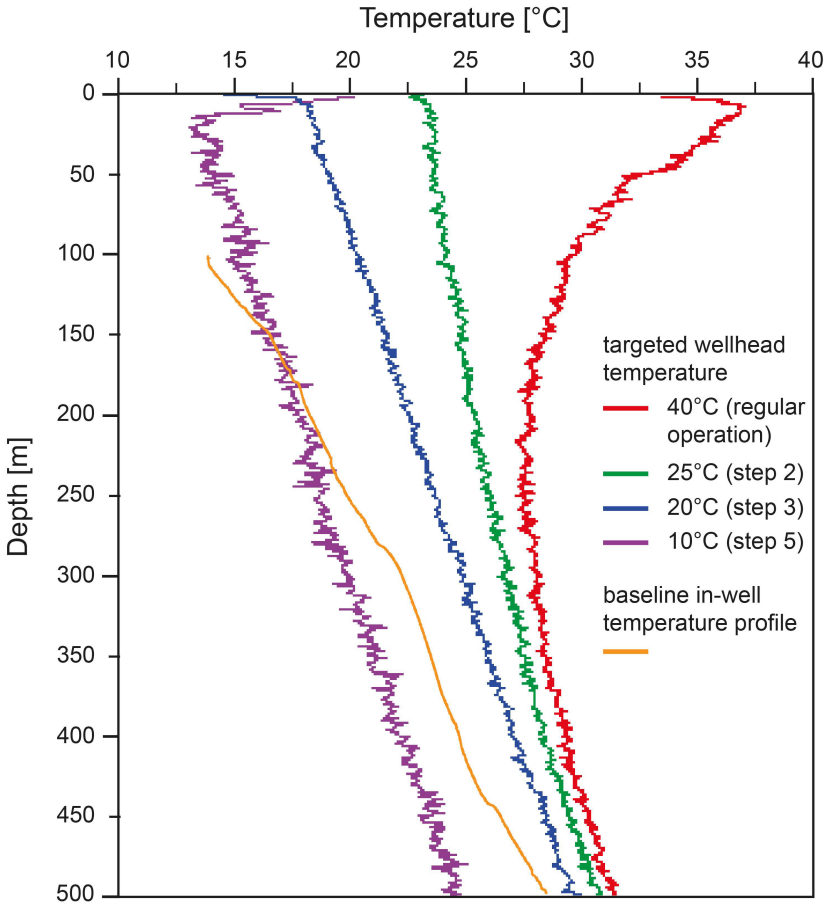

Fig. 3. Measured distributed temperature (DTS) profiles along the outside of the injection tubing during the different steps of the experiment (right to left): regular operation at 40 °C (red); 25 °C (green); 20 °C (blue); 10 °C (purple). The baseline in-well temperature profile (yellow) has been recorded during a logging campaign prior to start of injection.

5. Interpretation

The recorded wellhead and bottom hole temperature and pressure, the flow meter data and the DTS temperature profiles consistently mirror the evolution of the injection process from purely single-phase flow at higher wellhead injection temperature to two-phase flow dominated conditions at lower wellhead injection temperature. Down to a wellhead injection temperature of 25 °C (step 2) the recorded pressure and temperature data clearly show that throughout the entire injection well the temperature conditions are generally above the CO_2 liquid-vapour equilibrium and the injection process is single-phase (Fig. 4, left). The slight drop in wellhead pressure observed during step 2 (see Fig. 2) reflects the slight increase in density of the injected CO_2 as consequence of the decreased temperature. Assuming constant reservoir pressure conditions, an increase in CO_2 density increases the CO_2 in-well weight-column and by this lowers the wellhead pressure. The comparable small drop in wellhead pressure during step 3 with a wellhead injection temperature of 20 °C and continuous decrease in bottom hole temperature suggest still single-phase flow conditions. Slight fluctuations in wellhead pressure might, however, indicate onset of two phase flow conditions within the surface installations. During step 4 with a target temperature of 15 °C, the notable

drop in both, wellhead and bottom hole pressure suggests established two-phase flow conditions within the entire well. The drop in the bottom hole pressure during step 4 also supports the assumption of two-phase flow conditions with increased mean density below the P/T gauge at 550 m and eventually down to the reservoir. Finally, during step 5 with a target temperature of 10 °C, two phase flow conditions within the entire well and surface installation has been established (Fig.4, right)

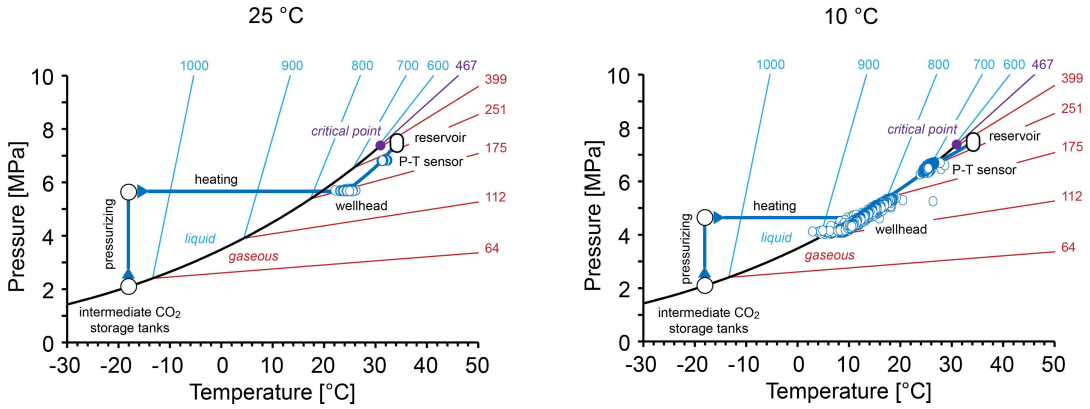

Fig. 4. Measured pressure and temperature data at the injection wellhead and the in-well pressure-temperature-gauge at 550 m depth shown within the injection process diagram of Fig. 1 for wellhead injection temperatures of 25 °C (left; step 2) and 10 °C (right; step 5).

Flow rate oscillations have been observed since the beginning of the CO_2 injection in June 2008 and are normal part of the injection process. Nonetheless, the injected mass of CO_2 over time is inevitably constant since the CO_2 is pumped via plunger pumps which operate always in the liquid (i.e. incompressible) CO_2 state and measured flow rates oscillate around the "true" flow rate as defined by the adjustments of the pumps by about ± 0.1 t/h. Oscillations in measured flow rate during regular injection therefore most probably reflect oscillation of the gaseous CO_2 in the surface pipeline and maybe also all the way down to the reservoir. During the cold injection experiment at decreased wellhead injection temperature these oscillations become, however, more pronounced. According to Fig. 2 the normal range of oscillations of about ± 0.1 t/h can be observed until switching to 20 °C although already during step 2 with wellhead injection temperature of 25 °C the mean flow rate of about 1.34 to 1.54 t/h as determined by the flow meter is slightly below the actual injection rate. According to the flowmeter manufacturer's manual, two-phase flow is out of the specifications and determined flow rates are in-correct. The slightly lower mean flow rate as determined during step 2 may therefore indicate onset of two-phase flow in parts of the surface installations already during step 2. At wellhead injection temperatures ≤ 20 °C (steps 3 to 5) recorded pressure and temperature data prove two-phase conditions throughout the surface installations, which is reflected by the overall much too low measured flow rate. The extreme oscillations during step 4 and especially step 5 reflect increasing fractions of liquid CO_2 droplets in the two-phase flow and suggest slug flow instead of homogeneous two-phase flow within the surface pipeline.

6. Conclusions

From an operational point of view, the injection of two-phase CO_2 posed no operational problems at the Ketzin pilot site. The injection process ran as smooth as in the standard operation before despite the slightly higher fluctuations in pressure and temperature. To monitor such a two-phase flow injection regime permanent downhole pressure and temperature monitoring is a great advantage and is highly recommended for any CO_2 storage project where two-phase flow in the injection well may establish. Beside pressure/temperature sensors at or near reservoir depth a DTS system along the injection well is of great added value to monitor and finally control the injection

process. Such a DTS system is especially important for injection regimes where the transition from single-phase to two-phase flow occurs within the injection well to determine the depth of this transition. Flow measurement may become an issue for two-phase flow and with regard to operational but also accounting purposes it must be ensured that the installed measurement devices are capable of handling two-phase flow.

Even for the lowest wellhead injection temperature of 10 °C during this experiment the CO_2 entered the reservoir at temperatures close to initial reservoir temperature. Therefore and also due to the comparable short duration of the experiment thermal effects of the "cold" CO_2 on the reservoir and cap rock, as discussed e.g. by [12], could not be studied. However, for this experiment these effects can reasonably well be assumed to be negligible with regard to reservoir integrity.

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