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CO2 Injection In Low Pressure Depleted Reservoirs

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Summary

Re-using depleted fields (and platforms and wells) offers advantages over developing storage projects in saline formations. However, with reservoir pressures after production sometimes below 20 bar, there can be a large pressure difference between the reservoir and the transport pipeline at the surface, which will be typically at pressures in the range of 80 – 120 bar. This pressure difference must be carefully managed to ensure that the temperature of the CO2, the surface installations and the well, remain within materials specifications and within proper operating boundaries. Pressure drops of the CO2 result in potentially large decrease in temperature, due to its high Joule-Thomson coefficient; in addition, the temperatures and pressures that occur in a typical CO2 transport and storage system are such that two-phase flow is likely to occur. Pipeline pressure and temperature management can easily be done in a single source- single sink scenario as the pipeline pressure is a free parameter. However, if the pipeline must act as a backbone for multiple wells at different reservoir pressure, pressure and flow management must be balanced carefully. In this paper, the differences between a pipeline as transport and a pipeline as backbone will be discussed in detail.

Introduction

In several member states in Europe, storage of CO_2 in the first CCS projects is likely to take place offshore. The North Sea area has significant storage capacity, a large part of which is in depleted fields. In The Netherlands, current CCS activities consider depleted gas fields as the best option, with on the order of 1 Gt storage capacity theoretically available in the larger gas fields.
While re-using depleted fields (and platforms and wells) offers advantages over developing storage projects in saline formations, they pose significant challenges associated with the often low to very low depletion pressures. With reservoir pressure after production sometimes below 20 bar, there can be a large pressure difference between the reservoir and the transport pipeline at the surface, which will be at pressures in the range of 80 – 120 bar. This pressure difference must be carefully managed to ensure that the temperature of the CO_2, the surface installations and the well, remain within materials specifications and within proper operating boundaries. Pressure drops of the CO_2 result in potentially large decrease in temperature, due to its high Joule-Thomson coefficient; in addition, the temperatures and pressures that occur in a typical CO_2 transport and storage system are such that two-phase flow is likely to occur.

This paper describes design considerations for a CO_2 transport and injection system that uses depleted gas fields in the North Sea; the system consists of a backbone pipeline with multiple injection wells. Recently, a single source – single sink design was made in the ROAD project, connecting a CO_2 capture system at E.ON's Maasvlakte Power Plant 3 with an offshore depleted gas field. Transport was designed to take place via a newly build and fully insulated offshore pipeline (length 25 km, diameter 16", design pressure 150 bar). The gas field had a depletion pressure of 20 bar (Boser and Belfroid)

To store CO_2 at an envisaged storage site some basic requirements have to be fulfilled:

- The temperature of the CO_2 at the platform has to be above threshold values to ensure stable phase conditions of CO_2 in the pipeline at the platform.
- The temperature of the CO_2 in the well should not be below the specification values of material and installations.
- To avoid hydrate forming in the reservoir the temperature of CO_2 at the bottom hole of the storage site must be above 15°C.
- High flow rates should be avoided due to limitations with respect to tubing vibrations. This is very dependent on the completion design and local flow conditions but can occur(?) especially at lower pressure due to the high velocities. For instance with an unsupported tail end of 100 m, the critical rate is less than 1MTa for a typical North Sea well at 20 bar.

For injection into a well, the boundaries are given by the pump/compressor system (and it's control) and the reservoir pressure. For a given well, the required wellhead pressure (or potential injection rate) is sensitive to the temperature of the CO_2 in the well and, hence, at the wellhead. In general, the pressure decreases from the sandface up to surface due to the hydrostatic head and increases due to frictional pressure drop. In general, at low reservoir pressure, friction is dominant whereas at higher reservoir pressures the hydrostatic head is dominant. However, for both cases at low to medium flow rates (less than 2Mta for a reservoir pressure of 100 bar and a typical North Sea well), the change in pressure from the sand face to the surface leads to the occurrence of two phase flow within the well. However, this results in a strong dependence of the required wellhead pressure on the wellhead temperature. For the ROAD system, in Figure 1, the required wellhead pressure is given as function of the wellhead temperature for two mass flow rates at different reservoir pressures. It is clear that at the wellhead often two-phase conditions occur which 'fixes' the pressure and temperature combination on the phase line (heavy curve in both panels in Figure 1).

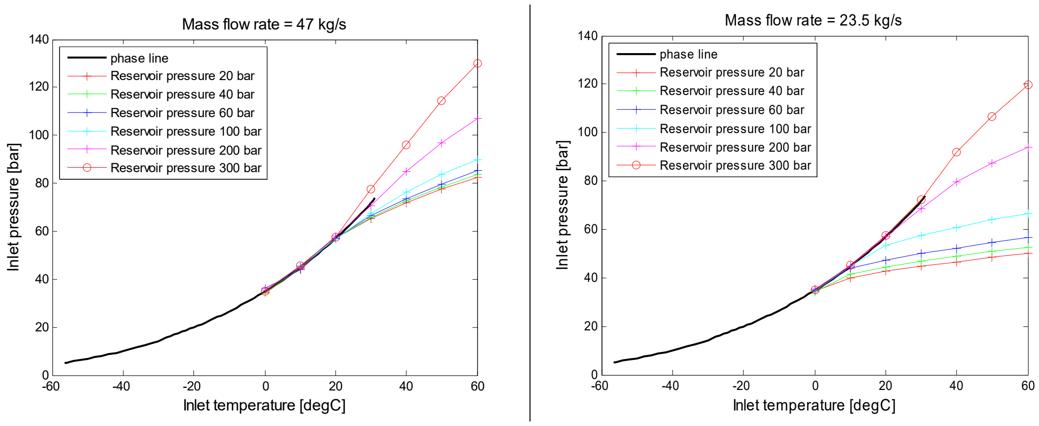

***Figure 1** Wellhead pressure as function of wellhead temperature for different reservoir pressures for a mass flow rate of 47 kg/s (left) and 23.5 kg/s (right). This is for a well with 3300 m TVD, md = 4200 m , ID = 7" and tubing size 5.5" (Boser and Belfroid).*

An important restriction in the design is the restriction of the downhole temperature to avoid hydrate formation. At most injection rates, the heat influx from the subsurface is limited and the system is almost adiabatic. This means that the temperature is dominated by Joule-Thomson effects, and if the pressure conditions downhole are below the critical pressure, again fixed by the phase line. For instance, for the ROAD system, the downhole temperature is plotted in Figure 2 as function of the topside temperature for two mass flow rates. The figure shows that for lower wellhead temperatures, the downhole temperature is corresponding to the phase line temperature independent of the wellhead temperature due to the occurrence of two phase flow conditions downhole. This means, that to ensure the downhole temperature is above 15°C, the pressure must be higher than the corresponding saturation pressure resulting in a minimum bottom hole pressure of 50 bar. This occurs at reservoir pressures of 50 bar or at high flow rates to increase the pressure drop in the reservoir along the well. To ensure a high enough downhole temperature at low reservoir pressure requires either a high mass flow rate (which leads to issues at start-up and shut-in) or high wellhead temperatures. For the ROAD system, this was solved by using the fact that a single source – single sink allowed pressure and temperature control at the shoreline inlet of the offshore pipeline, by adjusting the level of aftercooling at the compressor. At low reservoir pressure, the temperature was kept high, with at higher reservoir pressure, the temperature was lowered (increased aftercooling of the compressor) to keep the required injection pressure low.

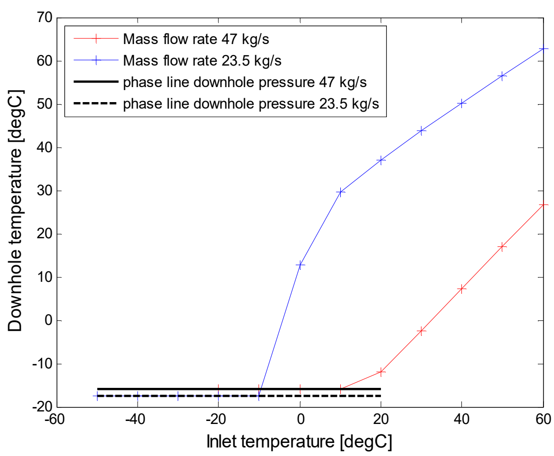

***Figure 2** Downhole temperature as function of wellhead temperature for a reservoir pressure of 20 bar and a mass flow rate of 47 and 23.5 kg/s (Boser and Belfoid).*

However, for a system consisting of a backbone pipeline with multiple wells at low pressure, the balancing between limitations is more difficult. For a backbone pipeline, all wells see the same back pressure and back temperature. Each well must be mass flow controlled, as the pressure drop across a control valve is not a viable control parameter due to strong link between the downstream pressure and temperature. The mass flow control also introduces pressure drop across the valve, resulting in low temperatures downstream of the control valve. This means that ensuring a high enough downhole temperature is difficult, and also resulting in potentially strict material specifications for all piping downstream of the control valves.

In a system with a mass flow control valve, the influence of the wellhead temperature on the well pressure drop behavior temperature is enhanced in comparison to the case without control valve due to the temperature drop across the valve. In Figure 3, the maximum flow rate as function of the platform temperature (the fluid temperature upstream of the well control valve). Additionally, the downhole temperature is given at a moderate flow rates for different platform temperature is given for a reservoir pressure of 20 bar. At full open flow, a lower pipeline temperature (lower than 50°C) is required for injection at higher reservoir pressures. However, this will result in low downhole temperatures in a well with a low reservoir pressure. This could be solved by cooling the CO_2 that is to be injected into the wells that have a higher bottom hole pressure.

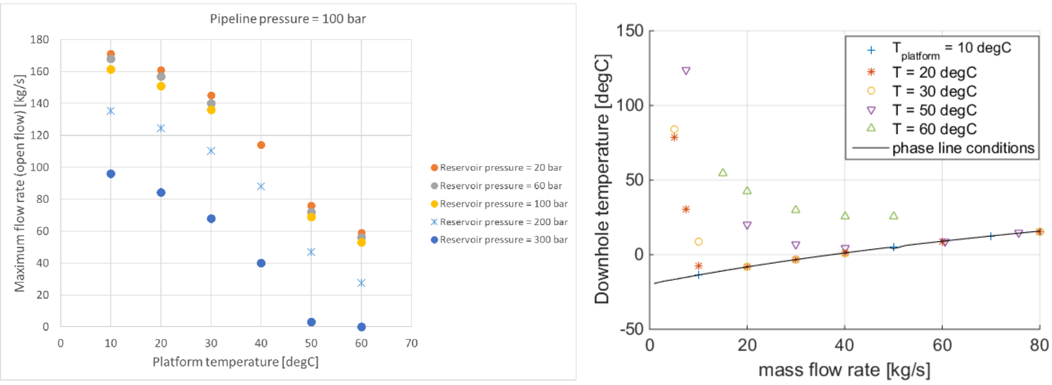

Figure 3 *Maximum flow rate as function of platform temperature (temperature upstream of well control valve) for a platform pressure of 100 bar (left). Bottomhole pressure as function of mass flow rate at different platform temperatures for a reservoir pressure of 20 bar (right).*

However, for longer backbone systems, insulating the pipeline is likely not a viable option.meaning that the arrival temperature will be typically 10°C, which is a typical value for the sea water temperature in the North Sea. At that temperature, ensuring a minimum downhole temperature of 15 °C, taking into account temperature dropdownstream of the mass flow control valve is almost impossible. Therefore, for these conditions, hydrate prevention and low temperature pipe materials are likely required.

Current research is aimed at developing injection scenarios to utilise the storage capacity represented by hydrocarbon fields with low to very low depletion pressures. While steady-state conditions, such as discussed above, must be carefully designed, transient operations, such as start-up and shut-in, lead to additional challenges.

The analyses presented in this paper result in a inventory of well head conditions (temperature, pressure, flow rate) and associated bottom hole conditions that will provide insight in the available options to transport and storage network operators to manage CO_2 injection into hydrocarbon fields at low to very low depletion pressures.

References

W. Boser, W and Belfroid, S. [2013] Flow Assurance Study*Energy Procedia*,37 , 3018-3030