CATO-2 Deliverable WP 2.1-D15B

Flow assurance studies for CO_2 transport

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1 Executive Summary

In order to compensate for the relative lack of experience of the CCTS community, Flow Assurance studies of new CO_2 pipelines and networks are a very important step toward reliable operation. This report details a typical approach for Flow Assurance study of CO_2 transport pipeline. Considerations to take during the design of a pipeline are highlighted, with an emphasis on operability of the system.

The steady state aspects of a pipeline operation are first addressed, putting some highlight into the nature of CO_2 flow in wells, and its intrinsic effects on pipeline outlet conditions. Two-phase flow in the wells cannot be avoided for a wide range of reservoir pressures, and the implications of this on the operability of a pipeline are being discussed.

Specific aspects relating to the injection into multiple wells are also looked at. It is concluded that it is not more challenging than a single well operation and that balancing effects between wells may even rend the operability of the entire system simpler.

Finally, transient phenomena during dynamic operations are addressed, with special emphasis on an Emergency Shut Down process as a worst transient scenario. Again, the worst case is obtained in the case of a single well, as the presence of additional wells provide a buffering effect for large pressure fluctuations. Large temperature drops at the wellhead may be unavoidable during an ESD, making the use of special (arctic rated) tubing preferable.

Distribution List

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Document Change Record

(this section shows the historical versions, with a short description of the updates)

Version	Nr of pages	Short description of change	Pages
2013.20.12		First Draft for review by partners	

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3 Introduction

The CCTS community is still rather inexperienced with the transport of CO_2 in pipelines. There are only a limited number of pipelines in operation, transporting mostly natural CO_2 and in the United States, with flow rates and CO_2 qualities that are different from what would be expected within a CCTS network. This lack of practical experience results in a need for adequate Flow Assurance studies before commissioning of a pipeline, to ensure that transport is safe and economical, in normal operation as well as during transients. This report details a typical approach for Flow Assurance study of CO_2 transport pipeline.

In the context of this report, transport is defined from the outlet of the compressor or pump station up to and including the tubing of the injection wells. Detail aspects of the transport scenario being analysed here correspond to injection into a depleted gas field. Such a reservoir type was chosen for it is the most probable candidate for CCS in Northern Europe. The overall conclusions drawn in this study are however not so much dependent on the type of reservoir used and can easily be extrapolated to other reservoir types or even depth, as was shown by Paterson et al. [1]

Apart from the economic constraints of expensive, large ID and often submerged pipelines, there are technical restrictions on the injection rates and injection conditions. These requirements on the injection stem from limitations set by, for instance:

- Thermal or hydraulic cracking in the reservoir due to the large influx of cold CO_2.
- Well integrity of the tubing, casing and cement linked to large pressure and temperature gradients along the well.
- The possibility of CO_2 hydrates forming in the near well bore area, due to the presence of water from the reservoir.
- Water or even carbon ice formation at lowest temperatures.
- Noise, pulsations and vibration induced by high flow velocities.

The wellhead and downhole temperatures are often the strictest constraints, combined with the limitations on the mass flow rate due to pipe vibrations and erosion. Although the injection fluid is often clean and can be considered particle free, during operation scenarios such as for instance a shut-in, temporary back flow might occur. In that case the fluid cannot be considered to be particulate free and an erosion limit must be considered. Therefore, the transport of CO_2 is severely constrained by the allowable injection conditions.

In this report, the basics of CO_2 transport and injection are discussed with respects to these limiting conditions. The pressure and temperature profiles in the well are discussed in Chapter 4 for different operating conditions, providing insights into the balance of forces at play during CO_2 injection. In Chapter 5, specifics of operating a network with multiple sources and sinks are being addressed. Dynamic operating scenarios are then briefly discussed in Chapter 6 to outline the potential challenges associated with transient operation of a CO_2 pipeline.

4 Fundamentals of CO_2 flowlines

4.1 Wellbore flow

When injecting into a well, the flow is fully determined by the wellhead temperature, the flow rate and the reservoir pressure and injectivity. All other pressures and temperatures throughout the well can be determined from these inputs, including the wellhead pressure. Furthermore, the wellhead temperature is determined by the pipeline heat losses and the pipeline inlet temperature as is described in the next section.

The pressure and temperature behaviour in the well is almost fully dominated by the thermodynamics of the fluid. The pressure drop through the well is made up of two components: the gravitational and the frictional pressure drops:

$$\frac{\partial p}{\partial z} = \Delta p_{gravity} + \Delta p_{friction} = \rho g + \tfrac{1}{2}\rho u^2 \lambda \frac{1}{D}, \qquad (1)$$

with $\partial p/\partial z$ and Δp the pressure gradients along the tubing [Pa/m], ρ the fluid density [kg/m^3], g the gravitational acceleration [m/s^2], u the fluid velocity [m/s], D the tube diameter [m] and λ the friction coefficient [-]. The gravitational pressure is the only component when a static column of fluid is present and corresponds to a hydrostatic head: it therefore tends to decrease the wellhead pressure compared to the bottomhole pressure. The frictional pressure drop corresponds to a pressure drop in the direction of the flow, due to friction. Since the flow is downward, its effect is opposite to the gravitational pressure drop: it tends to increase the wellhead pressure. In a production well, both of these components act in concert, resulting in the well-known Tubing Performance Curve (TPC).

Simulations of an injection well were performed with varying reservoir pressure and mass flow rate and a fixed wellhead temperature of 4˚C and 20˚C. The pressure profile along the well is illustrated in Figure 1 for variation of the mass flow rate and reservoir pressure at a wellhead temperature of T_in = 4˚C. For the higher mass flow rates, frictional pressure losses are dominant: CO_2 loses pressures at a faster rate due to friction, as it travels down the pipe, than the pressure built up due to the hydrostatic column of CO_2 above. For this pipe diameter (7" tubing), large flow rates are necessary to reach this condition. In fact, the injection rate of 200 kg/s (6.3 MTA) in this tubing corresponds to velocities within the well around 13 m/s. This is a relatively high velocity, as far as pressure drop is concerned and would not be recommended for normal pipeline flow. For an injection well, these velocities still present erosional risks. However if a clean particle free fluid can be guaranteed, these risks should be minimal. Vibrations risks of the hanging part of the tubing might be important and it should be taken into account in the completion design, such as tubing material and packer locations. If the packer is located far enough to the tubing end, these vibrations will be minimized For other intermediate flow rates, oscillations in the pressure profiles appear along the well (both during steady state and dynamic simulations) due to the presence of two phases along the well. In the same figure, the pressure profile is plotted for a fixed flow rate and varying reservoir pressure. It is interesting to note the similarity between these profiles. They are almost parallel, down to a reservoir pressure below 150 bara, when two-phase conditions occur around the wellhead. It should be noted that for these simulations (and these only), the bottomhole pressure was prescribed directly, rather than a reservoir pressure with an injectivity. Finally, some small fluctuations occur in the simulation at certain flow rate (and at reservoir pressure of 50 bars). These are due to code instabilities in the region around the critical point and should not occur in reality.

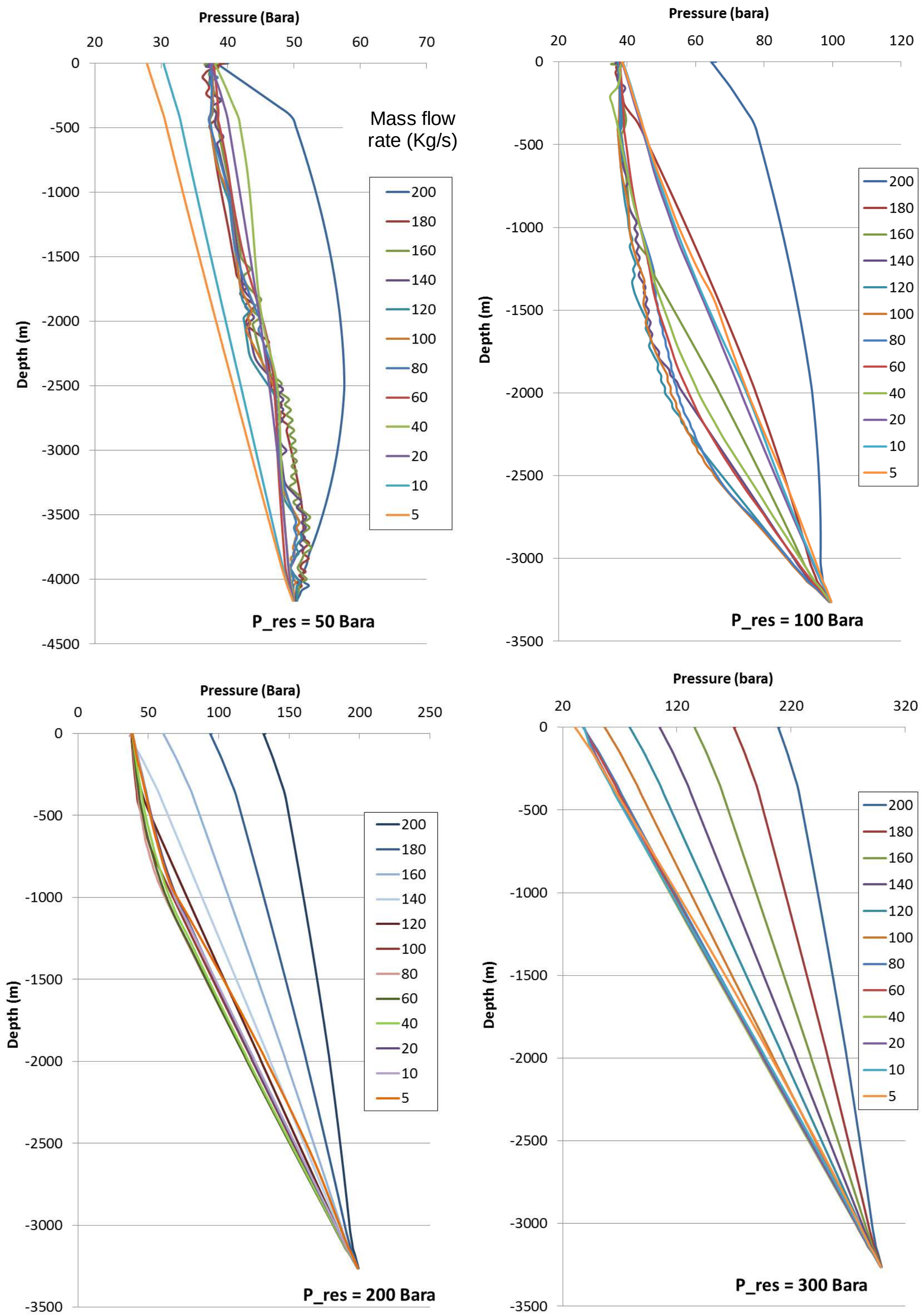

Figure 1: Pressure profile along the well for different flow rates and fixed reservoir pressures for well head temperature of 4°C and 7”well.

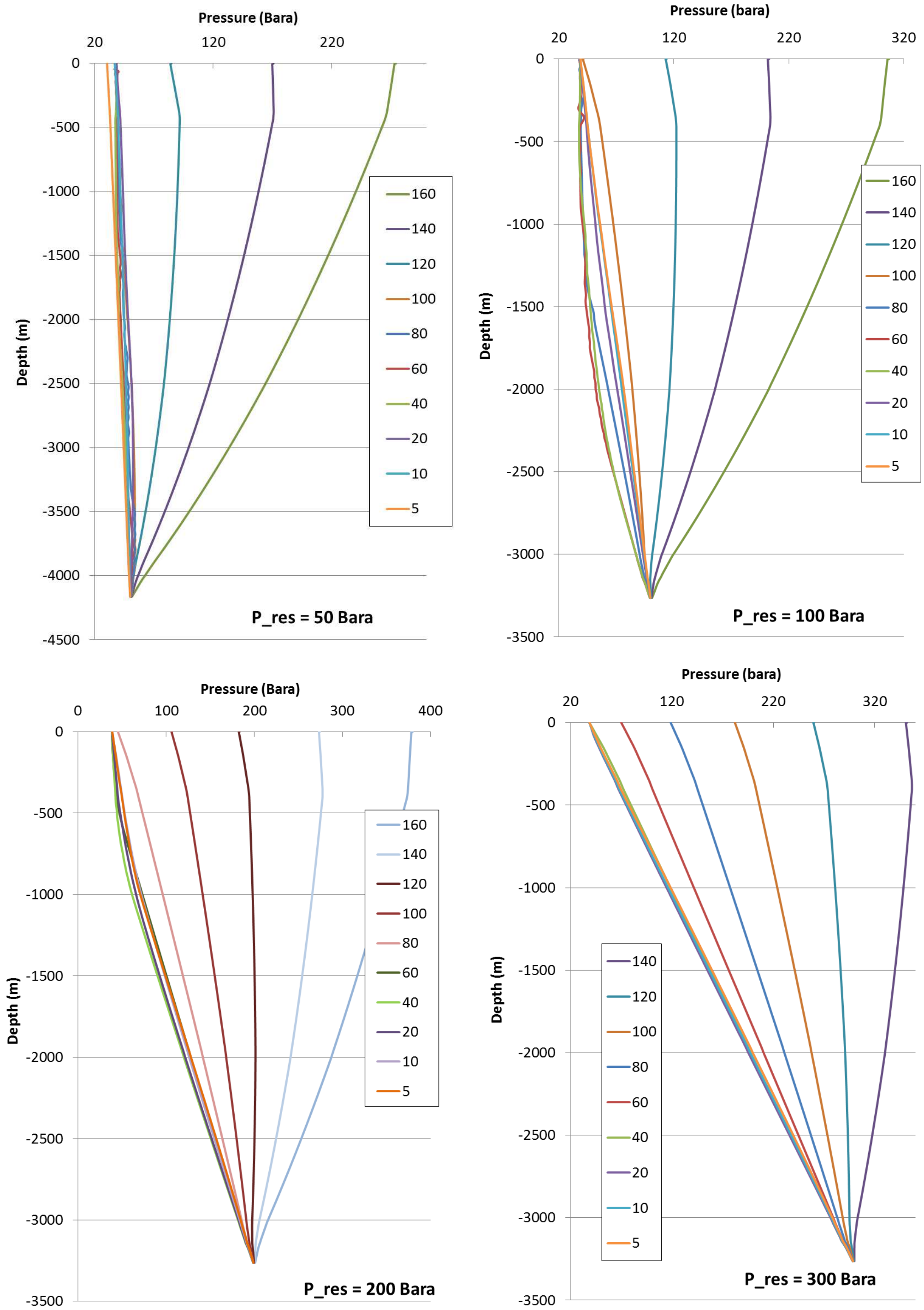

Figure 2: Pressure profile along the well for different flow rates and fixed reservoir pressures for well head temperature of 4°C (5"well)

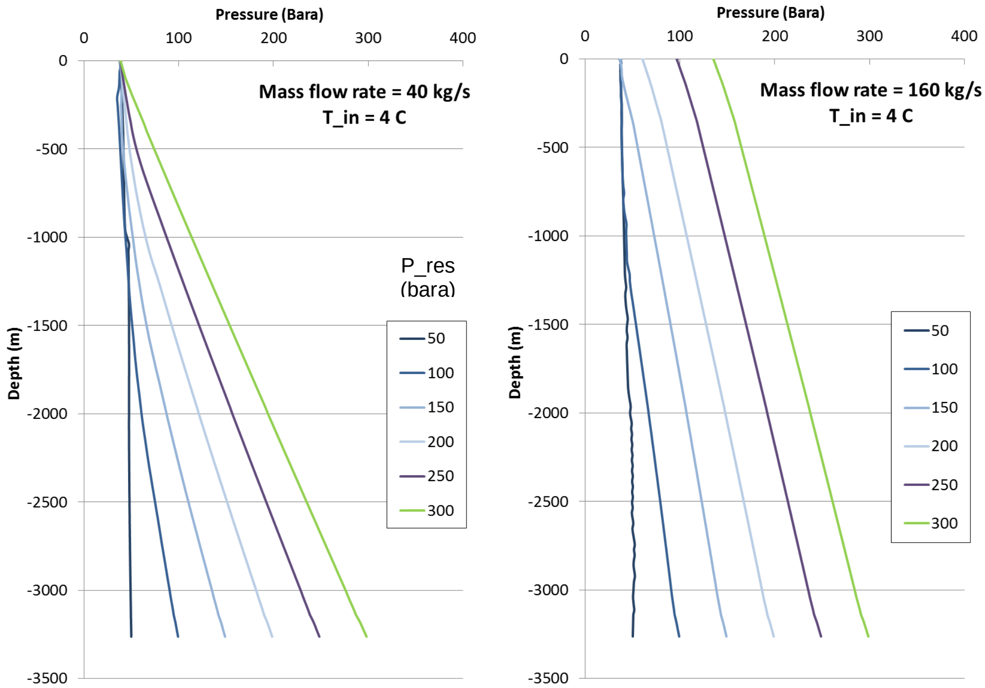

Figure 3: Pressure profile along the well for fixed flow rates and different reservoir pressures for well head temperature of 4°C

The wellhead pressure as a function of mass flow rate for different reservoir pressures are then shown in Figure 4. For a given reservoir pressure, there is a range of flow rates for which the wellhead pressure is constant. This phenomenon occurs when CO_2 at the wellhead is in the two-phase region, and result in wellhead conditions which are the same, independently of the reservoir pressure but dependent on the wellhead temperature. This range is much larger for the lower wellhead temperature of 4˚C compared to the 20˚C case. The former temperature corresponds to a flow that has cooled down to the sea bed temperature. This is of great interest for operation of a network where different wells, potentially drilled into different reservoirs or compartments and of different lengths could be operated with the same wellhead pressure. Discussions on this topic are presented in next chapter. It should also be noted that for wells of smaller diameter, i.e. injection through for example a 5” casing, the frictional pressure drop is larger, resulting in a shift of the wellhead pressure curves to lower mass flow rates.

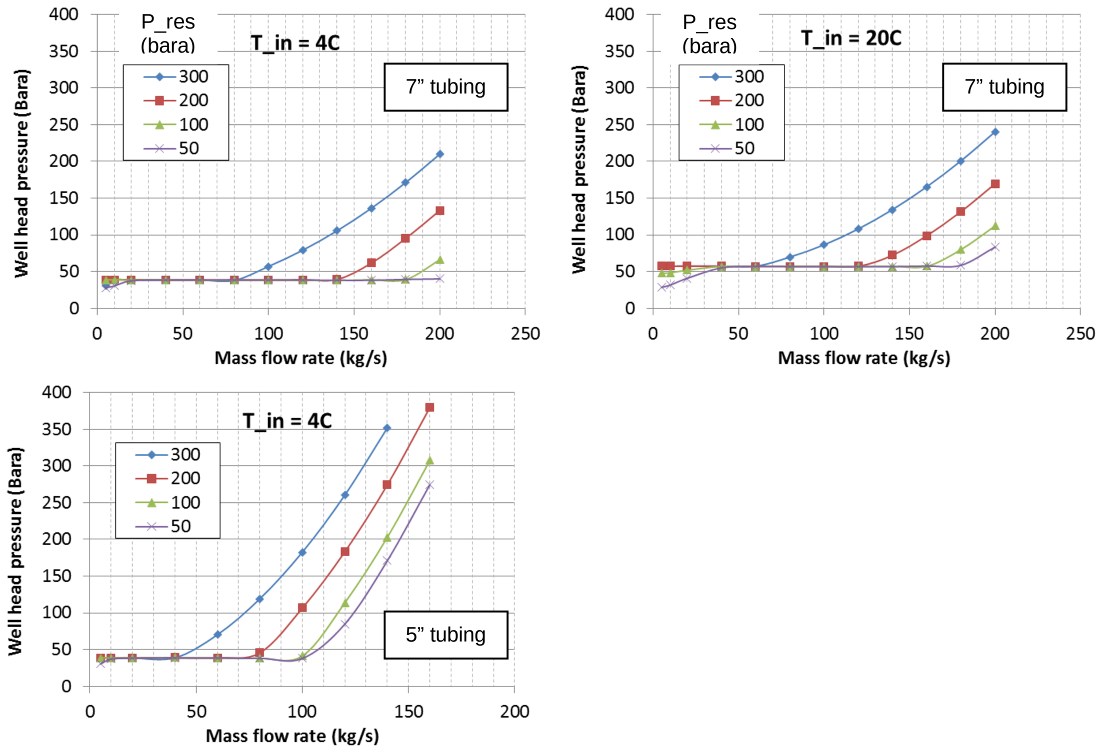

Figure 4: Wellhead pressure as function of mass flow rate for different reservoir pressures and fixed wellhead temperature of 4°C (left) and 20°C (right). Top: 7" well, bottom: 5" well.

The downhole temperature and liquid volume ratio in the well are plotted in Figure 5 as a function of flow rate and for different reservoir pressures.

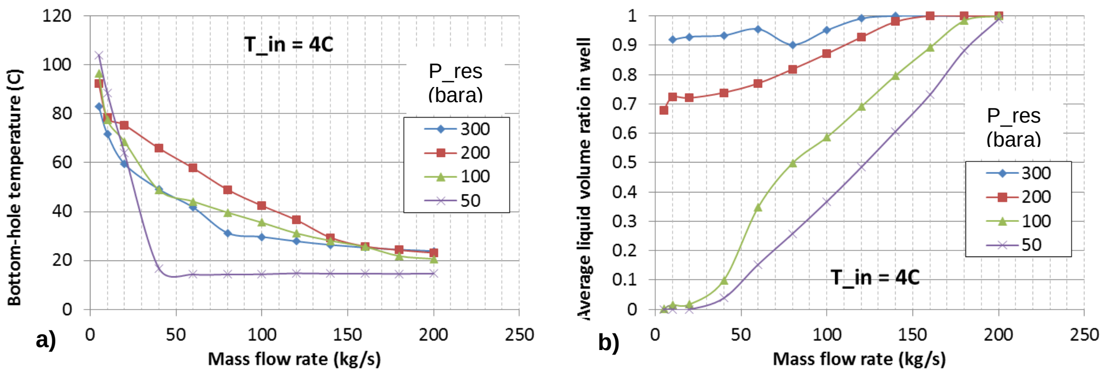

Figure 5: Bottomhole temperature (left) and average iiquid volume fraction (right) in the well as a function of flow rate and for different reservoir pressures.

At low flow rate, the downhole temperature is unsurprisingly high, partially due to heating through the casing, but mostly caused by compression of the CO_2. As the flow rate increases, the downhole temperature decreases. For a reservoir pressure of 300 bar, this decrease is initially (at low flow rates) more rapid than for reservoir pressure of 200 bar. This is due to the fact that at these flow rates, the wellhead pressure is independent of the bottomhole pressure, therefore a larger bottomhole pressure translates into a larger pressure drop, and hence more heat dissipation via Joule-Thompson expansion. For lower reservoir pressure, the wellhead pressure is almost always constant (See Figure 4), leading to a different trend, where the temperature drop is more pronounced with lower reservoir pressure due to increase in gaseous CO_2 as is shown in the same figure where the liquid volume fraction is clearly much lower for lower reservoir pressures.

4.2 Pipeline Flow

Simulations of CO_2 flow in a pipeline can also be performed to identify the expected arrival temperatures and required compression power. It is not the intention to fully describe the process behind designing a CO_2 transport pipeline. Some experience in this can be found in the literature [2] , although guidelines and standards are still not adequate due to the lack of experience in transporting anthropogenic CO_2. Nevertheless, for economic reasons, non-insulated pipes are likely to be used for offshore transport over great distances (of the order of 100 km). For such distances, the CO_2 transported, will have cooled down significantly and since it was shown that the wellhead temperature is a key parameter to the flow within the well, this cooling rate needs to be described. The pipeline considered here is 16"diameter and poorly insulated (U value of 5 W/m^2K) laying on the sea bed, with an ambient temperature of 4˚C, which is typical for a Northern Europe case. In order to prevent two-phase to ever occur in the pipeline, an arrival pressure of 80 bara is prescribed at the wellhead. This pressure is above the critical pressure and should result in a single phase, regardless of the local temperatures. Steady state results of OLGA simulations of such simple flow are shown in Figure 6 for two flow rates. The prediction shows sudden variations in pressure and temperature toward the end of the pipeline which are suspicious. These large fluctuations occur above the critical point, where a virtual delimitation is still made within OLGA between supercritical CO_2 and liquid CO_2. In reality, CO_2 properties vary smoothly, albeit significantly in this region, and such variations are not physical. Since OLGA is the preferred simulator for CO_2 pipelines flow assurance study, reliable simulations should be sought, and it is recommended for properly defined flow properties to keep the pressure higher than 80 bars.

Steady state simulations of 25km and 100 km pipelines are performed to estimate the expected arrival temperature of the CO_2, with the arrival pressure fixed at 100 bar. The simulator issues described above are completely avoided with this higher pressure. The arrival pressure as a function of mass flow rate is shown in Figure 7. Prior to the transport, CO_2 compressed to high pressures (100-120 bara) typically exit the compressor train at temperatures ranging from 40 to 80 ˚C. Therefore, a range of inlet temperatures was used for these simulations. Lower mass flow rate results in lower arrival temperature (sea bed temperature) due to the lower velocity of the CO_2, and therefore the longer residence time in the pipe. Even at high mass flow rates and high inlet temperature, the fluid has cooled down to around 20 ˚C at the outlet of the 100 km pipeline. Since transport lines are likely to be of a similar or much longer length (as for example the Karsto transport line [2]), it is reasonable to assume that the CO_2 will have cooled down to sea bed temperature upon arrival at the injection site. This assumption will be used in the following multiple sinks simulations.

In practice, in order to maintain the pipeline pressurized during injection, a choke needs to be installed at the wellhead. Choking of the flow is not an issue if the fluid is in liquid phase before and after the choke as this result in negligible expansion and temperature drop. It may however result in considerable temperature drops when the choked flow reaches the phase line (below 38.5 bara for 4˚C). Operating the wells such that the wellhead pressure is high enough for CO_2 to be entirely in liquid phase requires either a high flow rate, or to reduce the diameter of the injection tubing. This can be taken care during the design phase of the well but will also result in more stringent limitations in the maximum flow rate allowable.

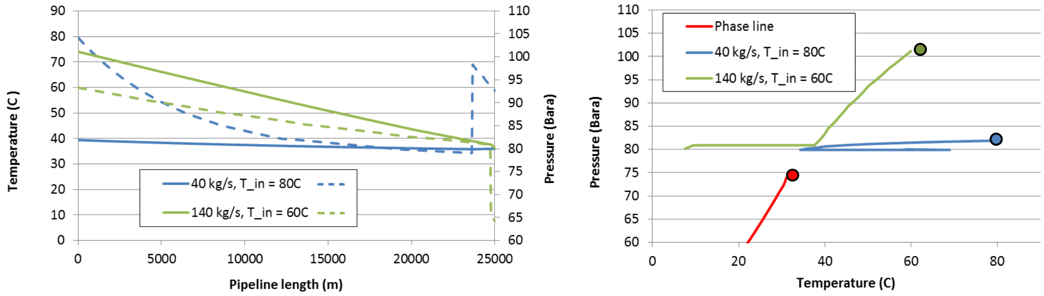

Figure 6: Steady state pipeline simulation results with outlet pressure fixed at 80 bars. Pressure and temperature along the pipe (left) PT diagram (blue and green dots representing pipeline inlet, red dot the critical point) (right).

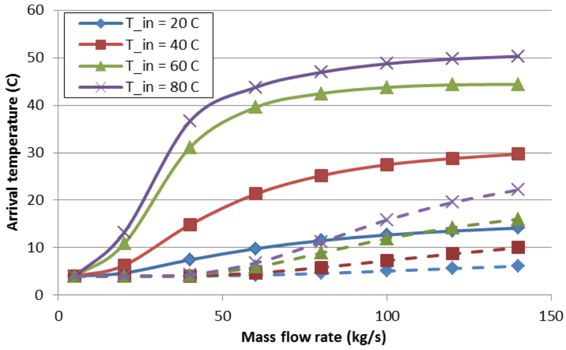

Figure 7: Arrival temperature as a function of flow rate for different inlet temperatures and inlet pressure of 100 bar. Plain lines: 25 km pipeline, dashed lines: 100km pipeline.

5 Operation of multiple sources and sinks network

In practice, after successful demonstration of CCTS operation, it is likely for a single pipeline to be connected to a number of sources and sinks. As was shown in the previous section, the flow in the wells dominates what happens on the entire chain, Therefore, whether one or more sources are connected to a single pipeline, and whether fluctuations of the CO_2 flow rate or purities are present is of secondary relevance. On the other hand, when a well is being shut down, for maintenance or in an emergency situation, may have some significant influence on the network operation. Thus, the response of a network consisting of a pipeline connected to two wells was studied in some details. The number of two was chosen as an extreme scenario: shutting down one well out of two is of greater consequence than stopping injection in one well when the network comprises 10 of them.

A network was analyzed, comprising of two wells of identical geometry connected to a single transport line (25km long, with inlet temperature set to -4˚C to simulate a much longer pipe). Each well was equipped with a 5" diameter choke, controlled via a proportional integral derivative controller (PID) to regulate the upstream pressure to 100 bara minimum. This ensures that two-phase flow will not occur in the transportation pipeline. In addition to this constraint, the compressor envelope at the pipeline inlet is assumed to be between 100 and 120 bara. This means that some large flow rates above 140 kg/s will not be achievable for reservoir pressure around 300 bara, as seen in Figure 4. These limitations in mind, simulations are performed to assess the operability of this two wells network.

Simulations are first shown in Figure 8, with slightly different bottomhole pressures between the two wells. The simulations were run dynamically to let the PID controllers adjust the choke settings of each well, until stable steady state flow profiles were obtained. The slightly different bottom hole pressures could for example occur due to a different depth of the wells or the presence of different compartments in the same reservoir. The dashed and solid lines respectively correspond to the high and low pressure reservoirs while the colors of the lines correspond to different total mass flow rates. In addition, the flow rate and choke openings for each well are shown in Figure 9. The wellhead pressures and temperatures from these simulations are the same for both wells, regardless of the prescribed mass flow rate. This has nothing to do with the presence of a PID on the wellhead choke, but is simply due to the fact that for all these conditions, the wellhead pressure is bound onto the phase line (i.e. fixed to 38.5 bara for 4˚C CO_2) This constitutes a self-regulating effect, with the flow rate being split equally between both wells, as illustrated in Figure 9: both the flow rates and the choke openings are identical, However, it also means that as a compartment of a reservoir fills up faster than another (for example because it is smaller), the injected mass flow rate does not decrease, and its reservoir pressure keeps increasing at a faster rate than the other larger compartment. This phenomenon occurs until the pressure is such that the wellhead condition is not prescribed by the presence of two phases. For a flow rate (per well) of 100 kg/s, this corresponds to a reservoir pressure slightly lower than 300 bars, as seen in Figure 4. To illustrate this, similar simulation results obtained with reservoir pressures of 320 and 280 bara and a range of flow rates are reported in Figure 10. In these pressure profiles, the wellhead conditions are clearly different between the high and low pressure wells. The mass flow rates are also different, with higher mass flow rate toward the lower pressure reservoir, even though the choke openings are the same. Since the chokes act on both the pressure and temperature for both wells, it is possible that there exist, for some downhole pressure and flow rate conditions, some other possible choke settings other than this "trivial" solution (both chokes with the same opening). This is however not investigated in more detail here.

Finally, it should be remarked that the temperatures within the wells are quite low (Figure 8) due to expansion of 100 bara liquid CO_2 to a liquid/gas mixture around 30 bara. Temperatures as low as -15˚C occur at the wellhead for the lowest flow rate, with further cooling as gaseous CO_2 expands while dropping down the well. This can be an issue for material specifications and can be avoided by setting a minimum allowable flow rate during injection.

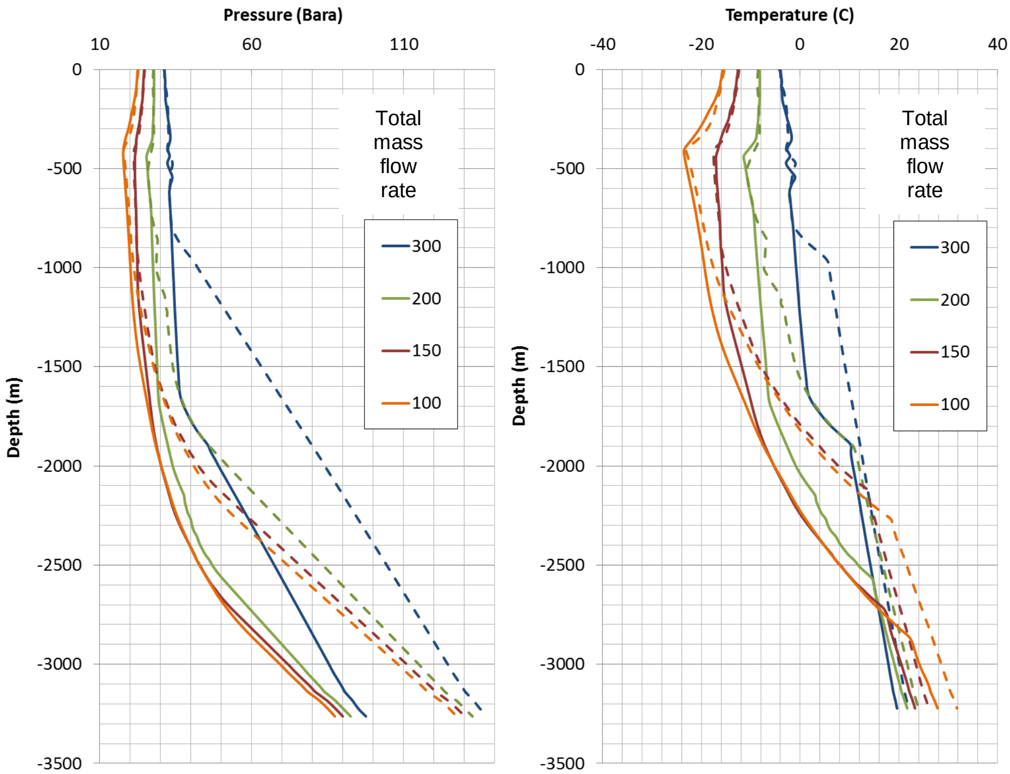

Figure 8: Steady state pressure (left) and temperature (right) along two connected wells, with reservoir pressures of 120 bara (dashed lines) and 80 bara (plain lines) and different total mass flow rates.

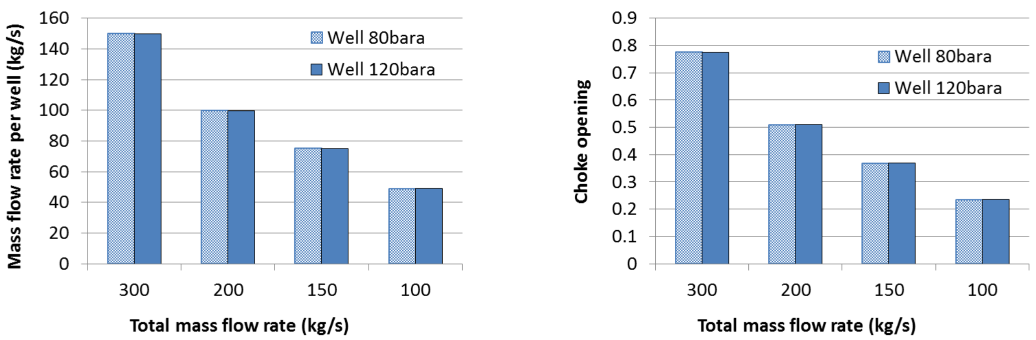

Figure 9: Calculated mass flow rates and choke settings for each wells of the simulations of Figure 8

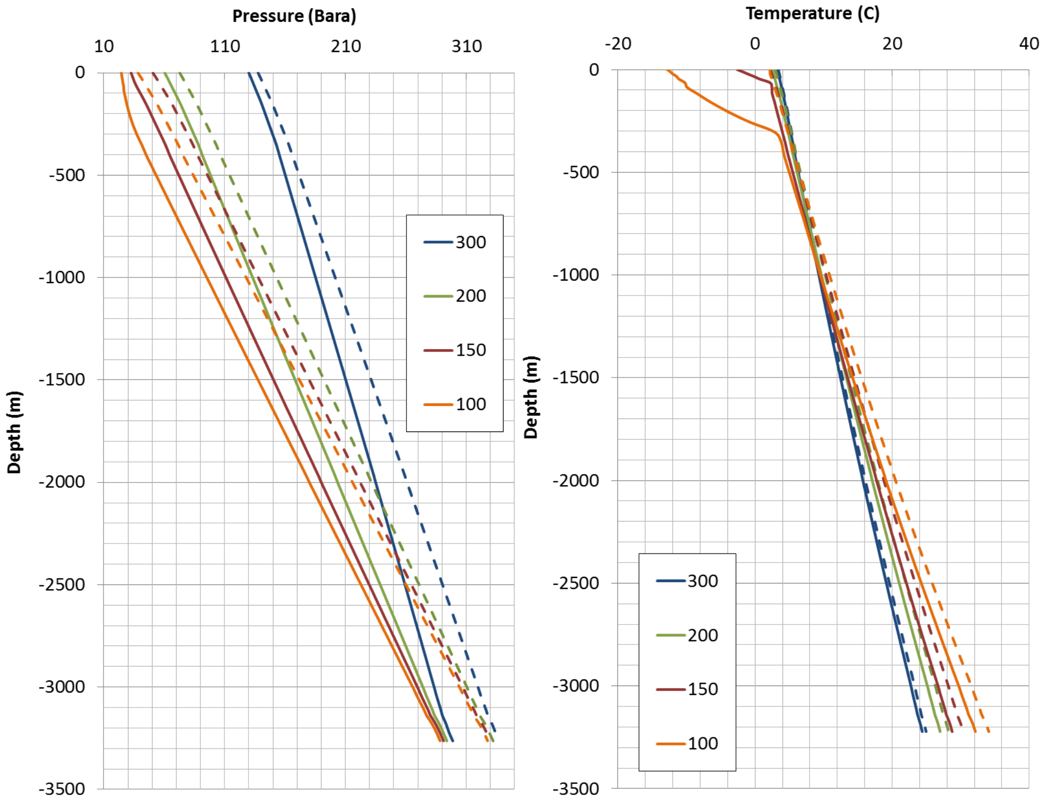

Figure 10: Steady state pressure(left), mass flow rate (top right) and choke opening (bottom right) per well along two connected wells, with reservoir pressure of 120 bara (dashed lines) and 80 bara (plain lines) and different total mass flow rates.

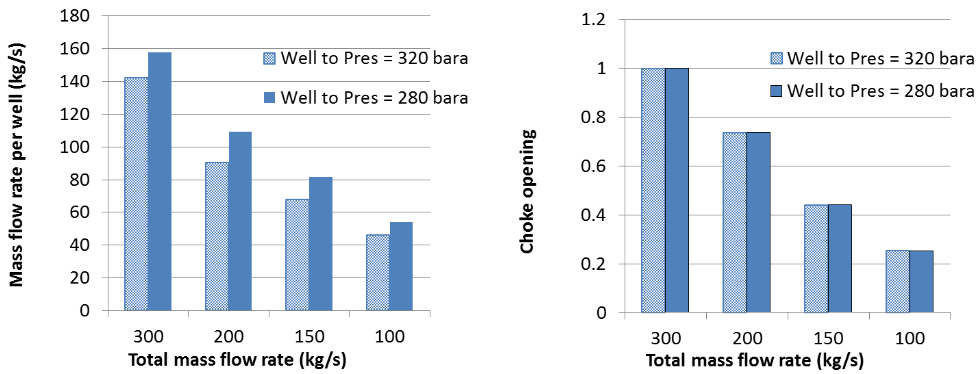

Figure 11: Calculated mass flow rates and choke settings for each wells of the simulations of Figure 10

6 Dynamic operation

During the process of performing a Flow Assurance study, a number of aspects need to be analysed. The first one is the steady state operation of the network, describing how normal operation should be conducted and how the flows should be distributed between different pipelines and wells. The considerations mentioned in the previous chapters should be addressed and the results will help evaluating for example compressor requirements, or the need for equipment such as a heater at the injection site. However, a number of transients are likely to occur during the lifetime of the chain, some of them may even be frequent. These dynamic operations will affect the flows and imply additional constraints on the pipeline designs. They should therefore be considered at the design stage of the chain. Such transients include:

- Shut-in of an entire pipeline, or of one of the injection wells. The most extreme case of which would be Emergency Shut Down (unplanned) of a single injection flowline.
- Cool down and depressurization of a pressurized pipeline from a high CO_2 temperature to a lower (ambient) one.
- Start-up of a pipeline from (partially) depressurized state until operation specifications (dense phase).

These transient scenarios are addressed in more detailed below, with some attention to the operational and design constraints related to them. They are first addressed for the most drastic scenario of a single-source single-sink chain, before addressing the specificities of a multiple sink network.

6.1 Single source and sink

6.1.1 Shut down

As an extreme scenario, a emergency shut down (ESD) scenario is considered with a cold injection with a temperature of 0°C at low reservoir pressure. This is representative if a long flowline to a depleted gas field is used, leading to cooldown of the CO_2 to sea temperature, or for instance when offloading from a CO_2 vessel. At steady state conditions of 47 kg/s, the wellhead pressure is approximately 35 bars. Again, this corresponds to the phase line conditions. At the same reservoir pressure and full shut-in condition (no flow), the wellhead pressure drops to 11 bars. A sudden pressure drop from 35 bars to 10 bars results in a temperature decrease down to -40°C (Figure 12). Simulations of an ESD were performed with a choke valve placed at the wellhead that was closed in 20 s, starting at time t = 2000s. Results are plotted in Figure 12. In this figure the wellhead temperature is plotted after a shut-in for a variation of mass flow rates and wellhead temperatures. Some fluctuations can be observed before shut-in: these are mainly caused by numerical instabilities due to a continuous boiling/evaporation at the wellhead, causing small pressure and temperature fluctuations, which result again in boiling/evaporation. A sharp temperature decrease is observed for all conditions shortly (about 300s) after the shut-in. This is due to drainage into the reservoir, which can occur very fast as the liquid drops down the well due to its own gravity, boiling and expanding the gas at the wellhead. Higher mass flow rates result in larger temperature drop, as can be seen on the left part of the figure. This can easily be explained by the fact that the difference between steady state wellhead pressure and shut-in wellhead pressure increases with flow rate, leading to increased Joule-Thomson expansion after the shut-in. The wellhead temperature also plays a large role during this ESD scenario, as can be seen on the right part of the figure. Increasing the wellhead inlet temperature can achieve an increase of the minimum temperature reached after the shut-in. This however, is only true up to an inlet temperature of about 20°C, corresponding to the departure from the phase line, as can be seen in Figure 14. Pre-heating can therefore not be used to warm-up the CO_2 above -15°C during shut-in, no matter how high above 20°C the pre shut down temperature is increased. A downhole choke could obviously be used to control the drainage of the liquid during the shut down. Usage of arctic condition tubing would also be recommended if frequent shut-ins are predicted during the injection lifetime.

In Figure 15, the liquid hold-up profile is plotted at different times after the shut-in, illustrating the drainage of the liquid in the reservoir aforementioned. Each blue line in this plot corresponds to the liquid hold-up, plotted as a function of depth at 5s interval. The thicker red lines correspond to 100s intervals. As can be seen, the liquid hold-up drops very quickly close to the wellhead, and much slower at the bottomhole. The spikes at the bottomhole are due to the tail-end that results in accelerating flows and decreasing pressure drops, hence with fluctuations in liquid hold-up. After 500s the complete well has been drained. This effect is to be expected for all conditions for which the steady state operating pressure is much higher than the shut-in operating pressure. Ripples in the liquid hold-up plot can be seen. These correspond to waves of larger liquid hold-up propagating down the well.

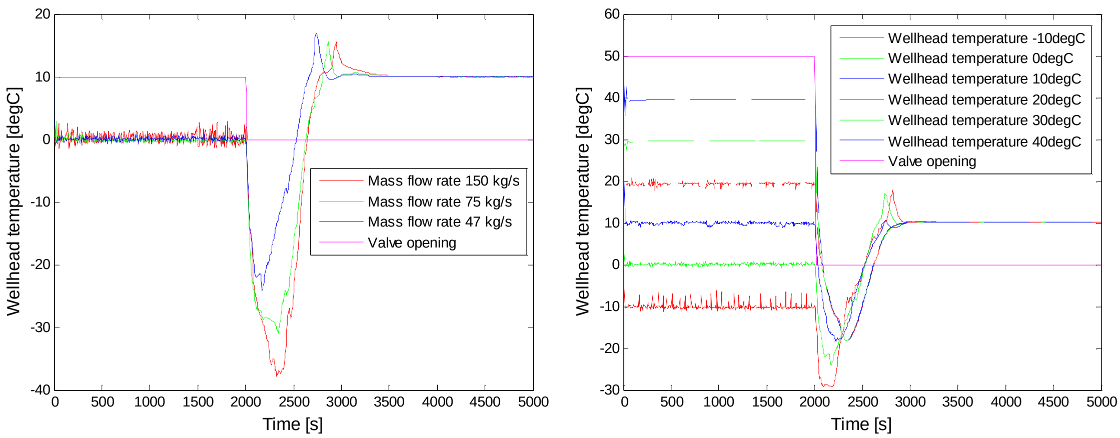

Figure 12: Wellhead temperature and valve opening as function of time for a shut-in scenario of 20s at a reservoir pressure of 20bar with a variation of the mass flow rate at an inlet temperature of 0°C (left) and a variation of the inlet temperature at a mass flow rate of 47 kg/s (right).

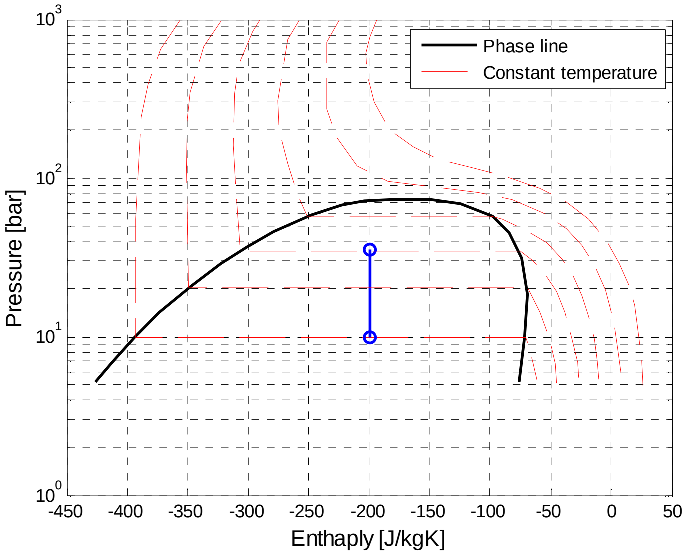

Figure 13: Mollier diagram of CO_2 with constant temperature lines of -80, -40, 0, 20, 40, 80°C. In blue the temperature decrease is indicated at the shut-in.

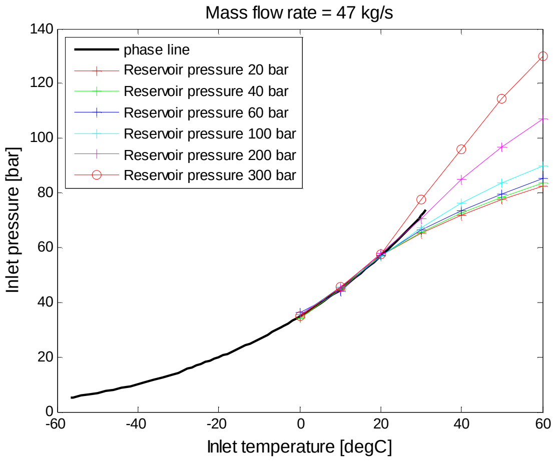

Figure 14: Wellhead pressure as function of wellhead temperature for different reservoir pressures for a mass flow rate of 47 kg/s

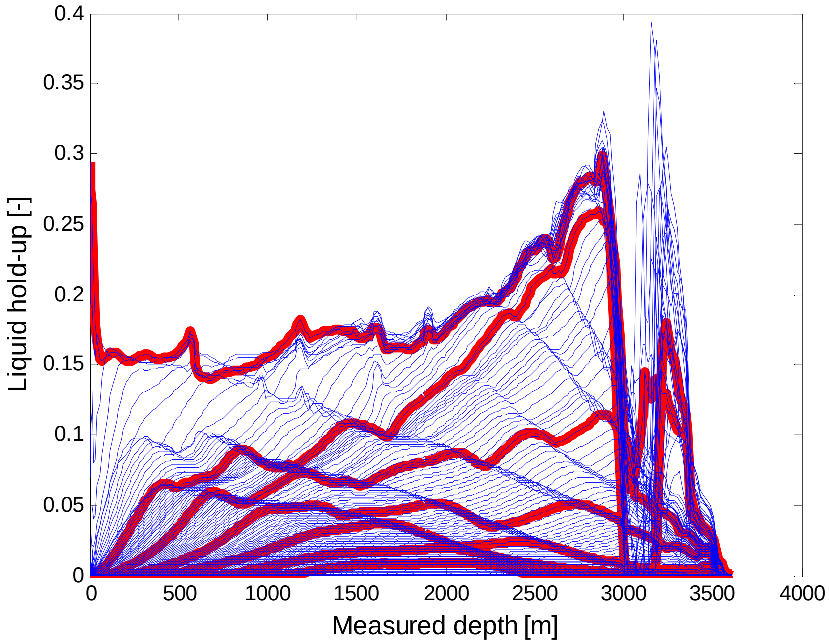

Figure 15: Liquid hold-up profile as function of measured depth after valve closure. Red lines indicate t=0, 100, 200, 300, 400, 500, 600s after the shut-in. The blue lines are the profile at a 5s interval.

Similarly to Figure 12 and Figure 13, Figure 16 shows the temperature drop at the wellhead after an ESD, but this time for a range of reservoir conditions and a fixed wellhead temperature of 40°C. The lowest temperatures are clearly observed for lowest reservoir pressures, never going below 0°C as soon as the reservoir pressure exceeds 100 bar. This is due to the higher wellhead pressure at static conditions with higher reservoir pressure. Depending on the specifics of the exact field where injection would occur (and the injection rate), it will take a certain amount of time to reach 100 bars, assuming injection starts with a "fully" depleted reservoir around 20 bars. For typical reservoir size in the North Sea region, this time amount to a couple of months, up to a year. This means the low temperature issue at the wellhead is only present for a short period of time (and a short number of cycles) during the lifetime of the injection.

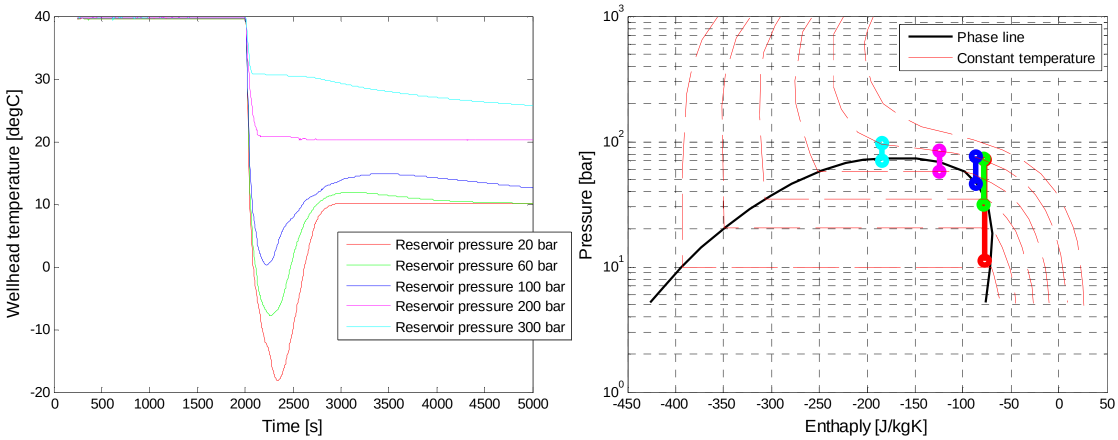

Figure 16: Wellhead temperature as function of time for different reservoir pressures for a mass flow rate of 47 kg/s and a wellhead temperature of 40°C. On the right the Mollier diagram of the shut-in cases with the markers giving the wellhead pressures before and after shut-in.

6.1.2 Cool down

In most CCTS chain operation, the CO_2 provided by the compressor train will be at elevated temperature (up to 100C and likely around 80C) when it enters the pipeline. In some cases, that temperature will even maintained as long as possible along the pipeline, via proper insulation, to ensure a high temperature at the injection side and mitigate some of the negative effects that may occur during an ESD. This implies that when there is a shut-down of the line, the CO_2 will cool down to ambient conditions, possibly inducing phase changes and related issues. This process can be simulated, for example by OLGA, as illustrated in Figure 17.

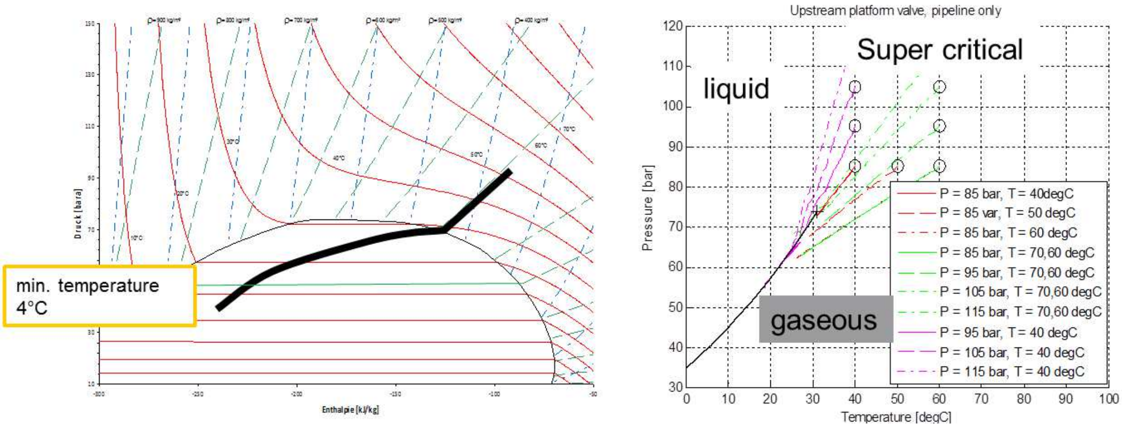

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Figure 17: Pressure and temperature evolution in a pipeline during cool-down

In such cool down simulation, it is apparent that the phase line is reached after a certain amount of time. For the cool down itself, it is not a problem as there is no flow, but it could be an issue when the flow is restarted. The time it takes until the fluid reaches the phase can be accurately predicted with software tools, translating into a maximum cool-down time for safe operation. After the phase line is reached, the predictions for the cool down are less trustworthy, as the evaporation process is not always very well handled in available tools. Predicted time for a complete cool-down is therefore to be used with care.

6.1.3 Startup

There are basically two kind of startups that may occur in the lifetime of a pipeline:

- Initial startup of the pipeline, initially filled with atmospheric pressure N2 or air.
- Startup of a pipeline filled with CO_2 at atmospheric pressure, for example after a depressurization and a maintenance

In the first case, it is likely that the pressurization would take place via a pig, with dense phase high pressure CO_2 pushing the pig and the air or N2 being vented at the platform. Such operation in itself does not consist any specific multiphase flow issue and is a process that is well known from operation of other type of pipelines.

In the second case, after partial or complete depressurization of the CO_2. It is also possible for the operator to decide to restart without a pig, by re-pressurizing the line with an inflow of warm and high pressure (dense phase) CO_2 from the compressor train and into the pipeline. This type of operation may present some issue as the CO_2 in the pipe changes phase from gaseous to liquid and dense phase as the pressure and temperature are being increased. It is a not very well known process, which can be simulated to some extend with for example OLGA. Figure 18 shows the hold-up as predicted by OLGA along the length of a pipeline during a re-pressurization process. It clearly shows that liquid slugs are to be expected , which may travel at relatively high speed in the pipe. The details of the dynamics of such process are however still very uncertain and no simulation can give accurate prediction of the exact transients that will occur. Only the re-pressurization time can reliably be predicted, which is of course a crucial parameter for the operator. More experience is still required to get a better understanding of the nature of the flow, the boundaries of slug speeds and induced stresses on the pipeline, and translate this into guideline for safe operation.

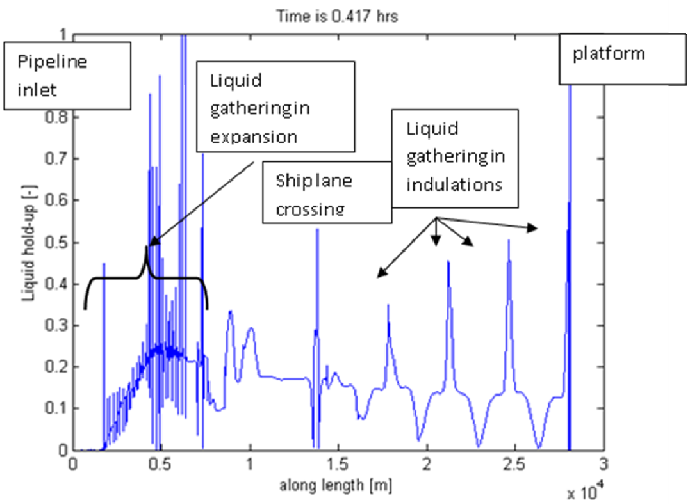


Figure 18: Liquid hold-up at an instant in time during re-pressurization of a pipeline

6.2 Specificity of multiple sinks dynamic operation

While the operation of a pipeline connected to a single well presents the most drastic transients in operation, a closer look is still needed to address what could be the specificities of operating a pipeline connecting several wells. The case of two wells is once again chosen here.

Shut-down and restart of a single well are presented in Figure 19, with both wells connected to a 25km pipeline and their chokes controlled via a PID controller to set the upstream pressure to 100 bara. In these simulations, the well connected to the 120 bara reservoir was shut-down suddenly (in 10s) at time t = 10h. All flow is therefore routed through the other well, connected to a 80 bara reservoir. At time t = 20h, the well is restarted again, also in 10s. There are no uncontrollable fluctuations during any of this entire process observed during these simulations. In the high flow rate case (300 kg/s total mass flow rate), the pressure on the wellhead of the well that remains open increases due to the added flow rate. This increased pressure would in practice not be supported by the compressor or pumping station upstream, which would force a lower pressure and therefore a decrease in flow rate. In both cases, low temperatures of the order of -40˚C are reached right after the shut-down of the well, due to expansion of gaseous CO_2. This however occurs during a very brief period of time and should not be sufficient to cause additional structural issue than the otherwise constant low temperature of around -15˚C.

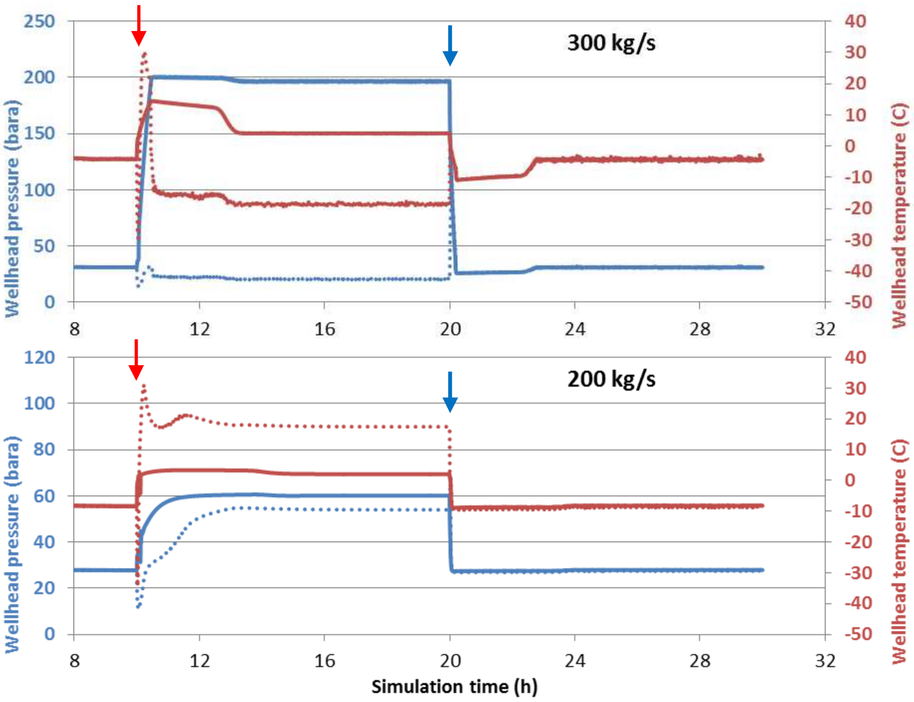
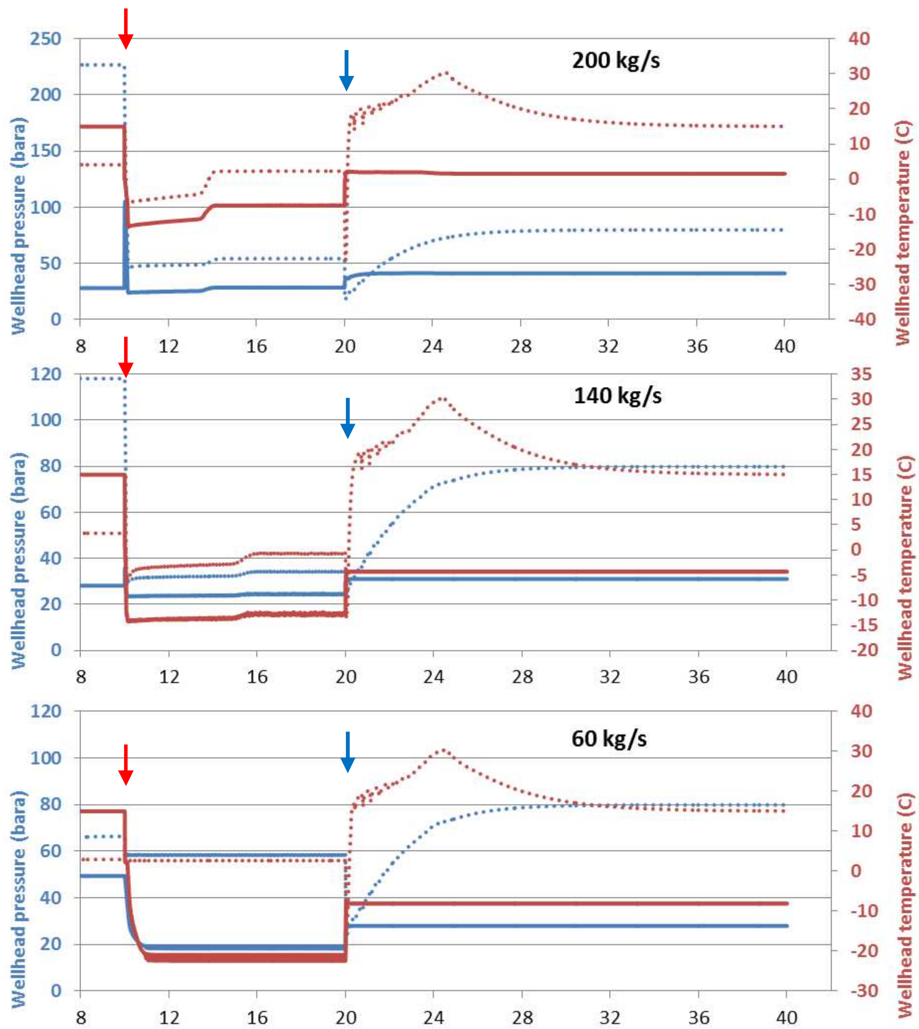


Figure 19: Evolution of pressure and temperature at the well heads when injection is stopped in a well connected to a 120 bara reservoir (dashed lines) and carries on in the well within a 80bara reservoir (solid lines). Total mass flow rate constant during the operation, injection in 120bara reservoir stopped t = 10h (red arrow), and restarted at t= 20 h(blue arrow).shut-down restart 1 well

Simulations were conducted to investigate the feasibility to switch injection from one well linked to a high pressure (i.e. full) reservoir to another well that is connected to a 50 bar reservoir. Results of these simulations are shown in Figure 20 for a range of mass flow rates. In these simulations, a given flow is prescribed at the pipeline inlet, with a single well connected. Then at time t = 10h, inflow to a second well is opened (within 10s). This second well is connected to a low pressure reservoir. After 10h, the choke to the first reservoir is closed. These actions are performed with PID controllers still in place to regulate potential oscillations in the pressures.



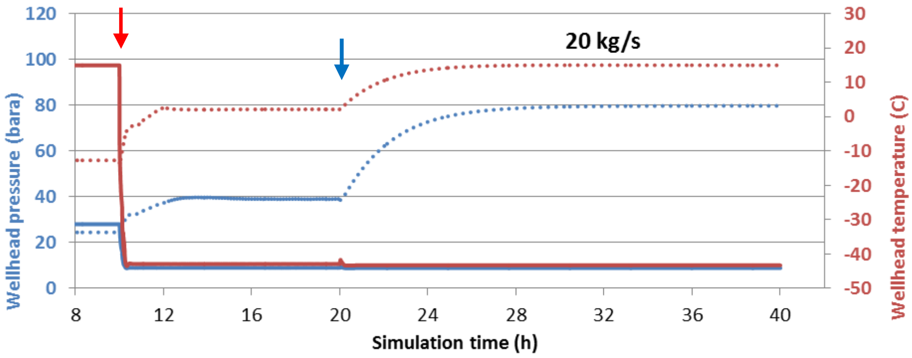


Figure 20: Evolution of pressure and temperature at the well heads when injection is switched from a well within a 300 bara reservoir (dashed lines) to a well within a 50bara reservoir (solid lines). Total mass flow rate constant during the operation, choke to 50bara reservoir opened at t = 10h (red arrow), choke to 300bara reservoir closed at t= 20 h(blue arrow).

The resulting pressure and temperature profiles are relatively smooth, with only a very small amount of oscillations observed at the wellheads. The transients can take in excess of 10h after shutting the initial well. The temperatures at wellheads can reach low values for low flow rates, but these are not different from what could be observed from a single well injection. This means that when injection should be switched from one well to another, the highest possible injection flow rate should be used in order to avoid low temperatures that could damage the wells. This should of course be within limits of the operating range of the compressor.

Note that these conclusions are valid for a larger range of pressure of the low pressure reservoir, as far as the flow rates are such that the wellhead pressure is dictated by the phase line. The very same figures can be obtained for example using a low-pressure reservoir with a pressure of 100 bara. Finally, while no results are presented with more wells (3 or more), the two wells case represents the most drastic situation. Flow conditions with 3 wells are in many respects similar, with less drastic transients, and much more operational flexibility.

7 Conclusions

Steady state simulations were performed on a CO_2 injection pipeline transporting pure CO_2 to a representative North Sea depleted gas field. The operating conditions for pipeline transport were observed to be fully determined by the phase behaviour in the wellbore. The pressure in the well was shown to be primarily dominated by the gravity component while the frictional component was of limited influence for practical injection rates, unless velocities are allowed to largely exceed erosional limits. Due to gravity the pressure decreases from bottomhole to the wellhead, resulting often in two-phase conditions at the wellhead, controlled by the wellhead temperature. This results in a quasi-constant pressure across a range of reservoir pressure which can benefit the operability of the injection system. Steady state simulations also showed that the fluid temperature in the well can almost be described adiabatically. Heating from the surrounding rock is minimal and the fluid temperature is determined by local compression or expansion.

The strong dependence of the required wellhead pressure on the wellhead temperature and mass flow rate results in strong responses in dynamic situations such as start-up, shut-in and emergency shut-in, especially, at low reservoir pressure. An ESD scenario was analysed in detail, leading to a sudden large decrease in temperature that is difficult to mitigate at low reservoir pressure. Procedures have therefore to be adapted in order to ensure safe operation.

The specific case of a multiple sink chain was looked at in some detail. Balancing of flow rates can be observed between wells whose reservoirs are at different pressure, but steady state and dynamic operation present no additional complexity compared to a single well chain.

[1] “Numerical modeling of pressure and temperature profiles including phase transitions in carbon dioxide wells”, L. Paterson, M. Lu, L. Connell, J. Ennis-King, 2008

[2] Havelsrud M., 2010, “The use of OLGA software for simulation of CO_2 transport: results from a recent project”, International Forum on Transport of CO_2 for Car bon Capture and Storage”, Newcastle, U.K.