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Quest CCS Project

Pipelines Flow and Flow Assurance Report - Final

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Summary

The document summarizes the key define phase flow assurance related issues for the Quest CCS project.

Keywords

Quest, CO2, CCS, flow assurance

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1. SUMMARY

Steady State Operations:

- Maximum injection rate into a single well is about 115,000 kg/hr (less than the design rate)
  - Rate limited by available wellhead pressure

Transient Operations:

- Shut-In (Well(s) trip but compressor remain on)
  - High pressure operation
    - o Compressor must be shutdown less than 1 hour after well trips to avoid high pressure setpoint
  - Low pressure operation
    - 1 well trips
      - o Remaining wells can handle increased flow, greater than 24 hours to restart shut-in well
    - 2 wells trip
      - o 6-12 hours to restart wells before reaching high pressure setpoint
    - 3 wells trip
      - o 2-6 hours to restart wells before reaching high pressure setpoint
- Shut-in (Compressor shuts down, but wells remain open)
  - High pressure operation
    - o 3 hours to restart compressor to avoid low pressure setpoint
  - Low pressure operation
    - o 1 hour to restart compressor to avoid low pressure setpoint
- Startup
  - High pressure operation
    - o Less than 1 hour to open wells before reaching high pressure setpoint
  - Low pressure operation
    - o 5 hours to open wells before reaching high pressure setpoint
- Liquid Surges in Wellbore
  - Pressure surges in reservoir not expected to exceed fracture pressure of formation
  - Backflow into well not expected

As part of this work, the following is recommended:

- Steady State Operation
  - Initially operate the system at high pressure to properly benchmark performance
    - Optimize compressor discharge pressure only after system performance has been benchmarked and the model updated

- Initial Line Filling
  - Set compressor discharge to high temperature to avoid low temperatures in pipeline
  - Monitor inlet pressure as this will provide the highest pressure reading and does not show any of the anomalous pressure decreases observed and reported in the select phase work
  - Monitor pressure at it rapidly increases once above 60 bar
- Pipeline Leaks
  - Unlikely to be detected with simple monitoring, such as rate of pressure change
  - Need to incorporate combination of pipeline line pressure, compressor discharge pressure and wellhead pressure drop to observe leaks of 5-10mm
- Pipeline venting
  - Three sections identified that will experience low temperatures during blowdown
  - LBV2-LBV3, LBV3-LBV4, all three well laterals
    - LBV2-LBV3 – fast dual-sided blowdown
    - LBV3-LBV4 – step-wise blowdown procedure
    - Laterals – step-wise blowdown procedure

2. PURPOSE AND OBJECTIVES

This work outlines the flow assurance recommendations for the Quest project. The main flow assurance issues were highlighted during the Define phase work. As system definition increased, this work expanded on the select phase flow assurance issues.

2.1. Background

The Quest Carbon Capture and Storage (CCS) project transports CO_2 from the Scotford upgrader in Alberta, Canada to an underground aquifer. This work is aimed at highlighting potential flow assurance risks associated with this project.

The design capacity of the system is to be able to capture 1.2 Mtpa of CO_2. To achieve this, a 12" pipeline is routed from Scotford to a series of three injection wells. The furthest injection well is located about 65 km from the Scotford upgrader.

Flow assurance for Quest prospect during Conceptual, Selection and Define design phases has considered the following 5 main aspects:

1. Design of the Surface System (e.g. Pipeline, Valves, Wellbore)
    a. Thermal-hydraulic performance of the system
    b. CO_2 Pipeline sizing and compressor requirements
    c. Maximum system capacity
    d. Insulation Requirements
    e. Vent-valve design
    f. Design requirements for above ground section of pipelines

2. Operability of the System
    a. Operability for normal operation
    b. Low flow events
    c. Emergency pipeline Leak/Blowdown
    d. Emergency wellbore blowout
    e. System start-up
    f. Vent-line operability
    g. Liquid hammer impact
    h. Low-water content operability

3. Solids Deposition Risk: Hydrates
    a. Dehydration limits
    b. Mitigation options

4. Multiphase Flow Aspects
    a. Two-phase flow in pipeline and wellbores

   b. Slugging potential
   c. Liquid hammer

5. Modeling Aspects
   a. Simulators applicability
   b. Impurities Impact

In this phase, the focus was on updating the models based on the latest information and ensuring the operability of the system. Many of the other aspects were covered during the Define phase flow assurance work(1).

3. FLOW ASSURANCE STRATEGIES

This section describes the flow assurance strategies used to mitigate each of the flow assurance risks. In addition, the flow assurance strategies associated with the main operating modes (start-up, steady state, and shut-in) were also addressed.

3.1. Solids Management

3.1.1. Hydrates

Hydrates will be managed primarily by dehydration of the injection fluids to sufficiently remove water and inhibit the formation of hydrates. The main risk of hydrate formation occurs downstream of the wellhead choke due to JT cooling. There is some uncertainty in the modeling, so a conservative estimate of the hydrate formation potential was assumed, but there is reasonable confidence that the risk of hydrate formation is low, given the anticipated dehydration level of the CO_2.

However, if hydrates form, they will be managed by chemical (methanol) injection. Note that an injection location is included in the design, but there are currently no plans to supply chemical at the injection location. Similarly, the exposed sections of the pipeline (low ambient temperatures) can be treated via chemical injection, but currently the plan is to supply the chemical only after there is a recognized hydrate issue.

3.1.2. Wax

The injection fluid does not contain any wax.

3.1.3. Pour point

The injection fluid does not have any associated pour point issues.

3.1.4. Asphaltenes

The injection fluid does not contain any asphaltene.

3.1.5. Scale

Scale formation will be mitigated by dehydration of the injection fluid.

3.1.6. Corrosion

Corrosion of the pipeline will be managed by ensure that the injection fluids are sufficiently dehydrated.

3.1.7. Emulsions

Emulsions are not an issue.

3.1.8. Slugging

Slugging is not an issue with these fluids. The operating conditions require that the fluid be in the single phase region. A previous study (2) looked at potential operation in two-phase flow and did not identify any slugging behavior.

3.1.9. Injected Solids

To prevent any reservoir impairment due to injected solids, a filter will be installed at each wellhead (3).

3.1.10. Chilly Choke

There is a large pressure drop taken across the well choke which results in some Joule-Thomson cooling. At typical operating conditions, the temperatures observed are well above any material integrity limits. Hydrate/ice formation may be an issue, but will be mitigated, as described above. Based on typical operating conditions, the lowest temperature expected downstream of the well choke is about -10°C, which is not sufficiently low to cause any issues.

There is considerable cooling anticipated during a blowdown of the pipeline. The vent pipe will be constructed of a material that can handle the low temperatures. Low temperatures in the pipeline will need to be managed by correctly implemented operating procedures as detailed in a subsequent section.

There is also a risk of cold temperatures during line filling operations when the compressor discharge pressure is high and the pipeline pressure is low. The primary mitigation strategy is to ensure that the compressor discharge temperature is set to a higher value (60°C) to ensure that downstream temperatures of the pipe wall do not drop below the design temperature.

3.2. Operational Considerations

3.2.1. Start-Up

Based on a previous study (2), the initial line fill (filling pipeline from low pressure) showed non-intuitive behavior, in that the pressure did not systematically increase with increasing amounts of CO_2 injected to the pipeline. The CO_2 condenses as the pressure is increased and the liquid phase is highly compressible. The current design case was similarly modeled and showed similar behavior, although at the pipe inlet (compressor discharge) the pressure remains relatively constant for most of the duration of the pressurization process. This location represents the highest pressure, so the pipeline inlet will be the primary means of measuring and controlling the system pressure.

There are also cases of normal start-up following a shut-in. There should be no issues here provided the wells and compressor are started at roughly the same time. Based on the analysis, there is some time from when the compressor is restarted until the wellhead choke needs to be opened. This time depends on the initial pressure in the pipeline and can vary from less than an hour to about 5 hours.

3.2.2. Steady-state

There should not be any flow assurance related issues during normal steady state production.

3.2.3. Shut-In

The injected fluid is sufficiently dehydrated so that there should be not issues upon shut-in. The main area of concern may the exposed section of pipe at the line break valves and the well pads. Upon shut-in, there is insufficient water to form any type of blockage and upon restart and deposits that were formed would be easily removed as the flow warms those bare sections of pipe.

During a typical shut-in, the pipeline will cool to ambient conditions. As the fluid cools, the pressure is also decreased and can cool into the two-phase region. This should not cause any operability issues but will result in the low pressure alarm during an extended shut-in.

3.2.4. Pipeline Venting

Cold temperatures can occur in the pipeline during venting procedures. The primary mitigation strategy is the controlled venting of the fluid from individual section between the various line block valves. Several sections show the potential for this cold temperatures, but the temperatures can be controlled by increasing the rate of venting from that section.

One section (LBV3 to LBV4) contains a significant low spot and will need a more controlled venting process to avoid the low temperatures. Based on the simulation work, it appears that by venting this section is a step-wise fashion with work. However, it is recommended that a detailed operating procedure be developed for this section once the system is operating and some of the currently unknown parameters are determined. The laterals will require a similar step-wise reduction in pressure.

In this case the unknown parameters include the ambient conditions at the final burial depth of the pipeline. The soil thermal properties are unknown as well. Upon initial injection of the CO2, temperature and pressure data at the inlet, outlet, and several intermediate locations will be sufficient to benchmark the models and get more accurate estimates of these unknown parameters.

3.2.5. Liquid Surges

Fluid hammer was evaluated during a shut-in. In all cases, the pressure surge in the system was less than the maximum system design pressure of 147.9 bar. Injection of the full design rate of 1.2 Mtpa into well 1 while the system is operating at the maximum design pressure resulted in pressure surges that were close to the maximum design rating of the pipeline. At the normal operating pressures of 120 bar, the pressure surges predicted were all much less than the maximum design pressure in the pipeline.

This issue was also investigated in the wellbore upon shut-in. The primary risk here is associated with pressure surges at the bottomhole that result in inflow back into the well from the reservoir. This phenomena has been observed with water injection wells. Due to the higher compressibility of the CO_2, similar issues were not observed.

4. BASIC DATA

4.1. PVT and Reservoir Data

A summary of the reservoir data is shown in Table 4.1. There is a considerable range of reservoir injectivity values considered. Depending on the scenario, either the high or low injectivity values represented the worst case, so most simulations include some sensitivity to this value, with the worst case being either the low or high value depending on the particular scenario. Note that these injectivity values are slightly changed from the previous work. The values are now specified in different units (liquid volume rate) instead of relative to gas a standard conditions. These values are based on water injectivity tests, so are expected to be more accurate. Although the injectivity values still cover a considerable range, but is a smaller range than previously assumed.

Figure 4.1 shows the original geothermal gradient used in the wellbore modeling. Note the reservoir temperatures do not match between Figure 4.1 and Table 4.1. The DTS trace is believed to have been taken prior to establishing thermal equilibrium, so the linear approximation is probably more accurate. This does not have any significant impact on any of the pipeline modeling or wellbore injection scenarios.

Table 4.1 Summary of reservoir characteristics (4)

Reservoir Temperature [degC]	60
Reservoir Pressure [bar]	200
Max allowable bottomhole pressure [bar]	280
Reservoir Injectivity [m3/d/MPa]	
Low	300
High	3,000

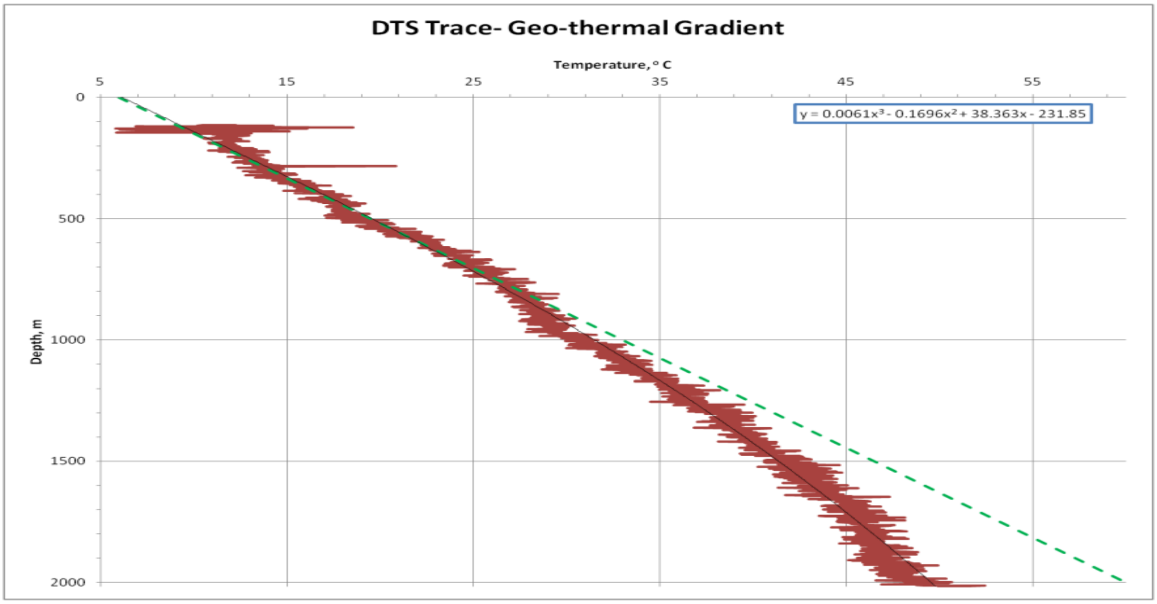

Figure 4.1 Geothermal temperature profile for wells (5)

4.2. Fluid Compositions

Fluid compositions are defined in Table 4.2 for both the normal and upset cases. In all OLGA simulations, due to limitations in the model, a pure CO_2 stream was used, but this does not result in a material difference in the results as the phase properties of the normal composition and pure CO_2 are so similar.

Table 4.2 Fluid composition of injection fluid (4)

Component	Normal Operation Mole%	Upset Condition Mole%
CO_2	99.2	95
CO	.02	.15
N_2	0	.01
H_2	.68	4.27
Methane	.09	.57
Water	<52 ppm	52 ppm

4.3. Water Samples

Free water is not expected in any injection scenario. The design case is to dehydrate the CO_2 to less than 6 lbs/MMscf during injection. The performance of the TEG unit used to dehydrate the CO_2 is a function of the ambient temperature. During normal winter operations, i.e. colder ambient temperature, the water content should be about 4 lbs/MMscf, while at the warmer summer temperatures, the water content is increased to about 6 lbs/MMscf. During both the anticipated winter and summer operations, all water is dissolved in the CO_2 phase.

4.4. Hydrates

It is possible to form hydrates from mixtures containing CO_2 and water. Figure 4.3 shows the predicted hydrate curve for the normal operating conditions. As previously reported (2), over the range of compositions expected between the normal and upset conditions, the impact to the hydrate equilibrium conditions is very small. The dehydration of the injected CO_2 effectively inhibits any hydrate formation during normal operating conditions in the pipeline. Based on the initial recommendations, dehydration of the injected CO_2 was sufficient to prevent hydrates at normal shut-in conditions of 0°C and 140 bar. However, hydrate formation was still possible during events, such as JT cooling across the well choke.

As part of this work, the validation of hydrate equilibrium in the presence of a small amount of water was investigated more closely. Figure 4.2 shows a comparison of the STFlash (in-house Shell software) and MultiFlash (commercial software) and how well they predict the water content of liquid CO_2 near the region of interest for the Quest project. Note that STFlash matched the data quite well, while MultiFlash under-predicted the data by an order of magnitude. The data and STFlash show that water is quite soluble in liquid CO_2. This implies that hydrate formation in the presence of liquid CO_2 is inhibited because the water is highly soluble in the liquid CO_2.

Figure 4.3 shows the hydrate equilibrium curve for both STFlash and MultiFlash. In the presence of free water, both programs predict nearly the same hydrate equilibrium curve. As the water content is decreased, the two programs begin to diverge in their predictions. The figure shows that the increase water solubility predicted by STFlash is sufficient to prevent the formation of hydrates. Conversely, MultiFlash predicts hydrates are stable even in the presence of liquid CO_2. Note that this difference only occurs at low water content with liquid CO_2. At all other conditions, the two programs predict very similar results.

Based on the data, the STFlash predictions are expected to be more accurate. However, note that there is very limited data available to benchmark the models. And the data themselves are difficult to measure and prone to errors. Therefore, to be conservative, the MultiFlash predictions are still being used in developing the hydrate mitigation strategies, but it is recognized that this approach may be overly conservative.

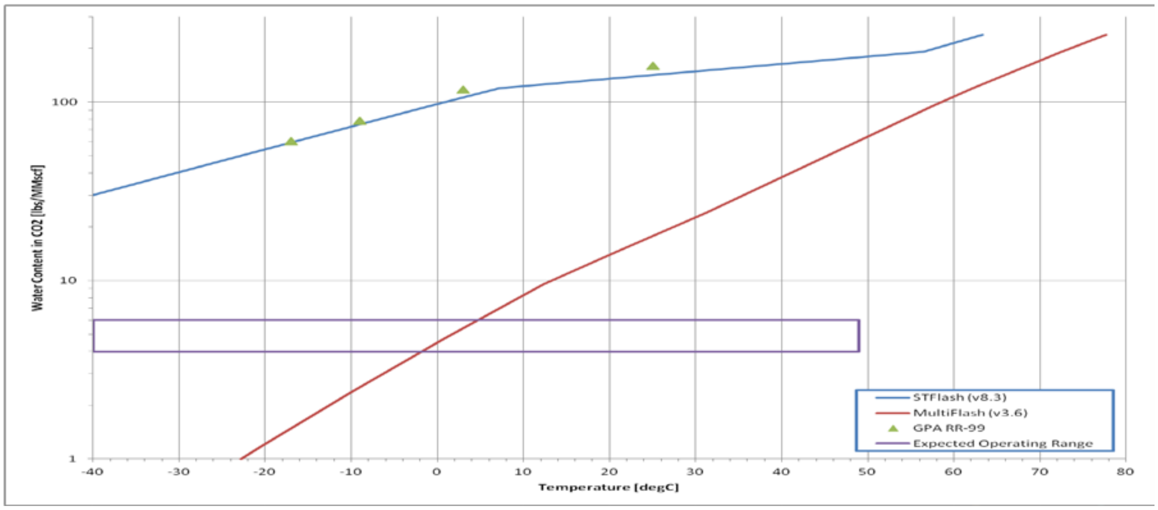

Figure 4.2 Model prediction and comparison with experimental data (6)

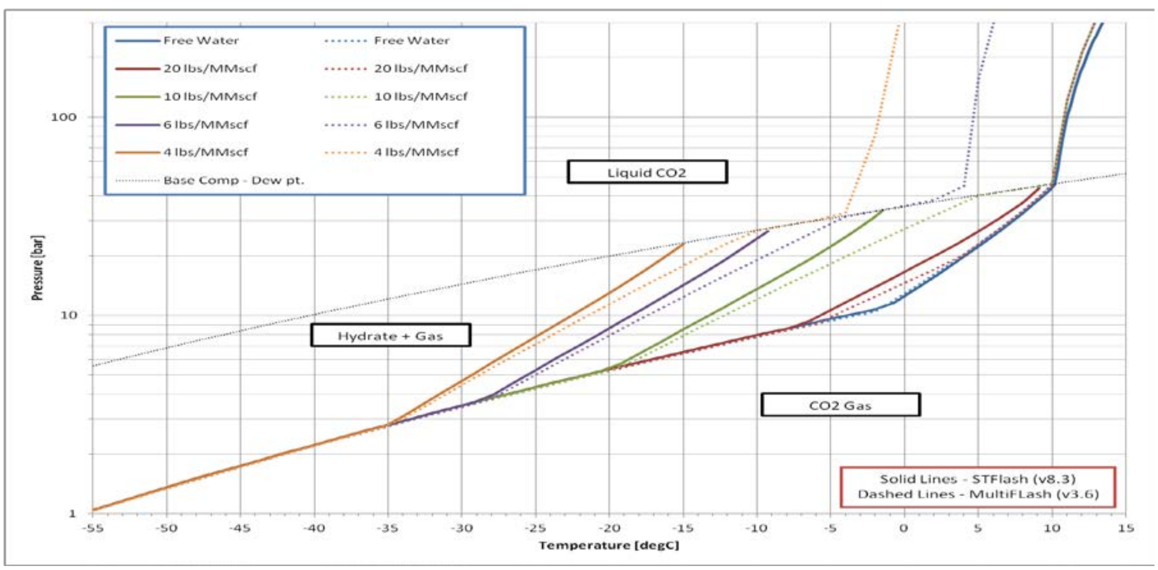

Figure 4.3 Predicted hydrate curve for composition during normal operation

4.4.1. Hydrate Inhibition Requirements

In several of the cases, assuming the less conservative hydrate predictions, it is possible to form hydrates, which means that a hydrate mitigation strategy is needed. One option is to use a hydrate inhibitor to prevent the formation of hydrates. In this section, the dosage requirements for the prevention of hydrates using methanol are given. The results are given in Figure 4.4 and Figure 4.5. The first figure shows the impact of temperature at a constant pressure. As is typical, the lower the temperature, the higher the methanol requirement to fully prevent hydrate formation. The methanol dosage requirement continues to decrease with increasing temperature until the temperature is sufficiently high that hydrates are no longer stable. The second figure shows similar results, but here as the pressure was decreased, the methanol requirement is shown to decrease as well.

In both figures, the methanol requirement is shown as a function of the water content. For all conditions given, the higher the water content, the higher the methanol dosage requirement required to prevent hydrates. Also in both cases, there was a sharp break in the curve predicted, which was the result of the differing water content of the fluid.

As with the prediction of the hydrate curve, methanol solubility in the liquid CO_2 phase is difficult to predict. Based on limited data, the actual methanol values may be twice as high as given in the figures. Despite these high methanol dosage rates, given that the water content is low (<50 ppm), the total methanol volume requirements are also be low.

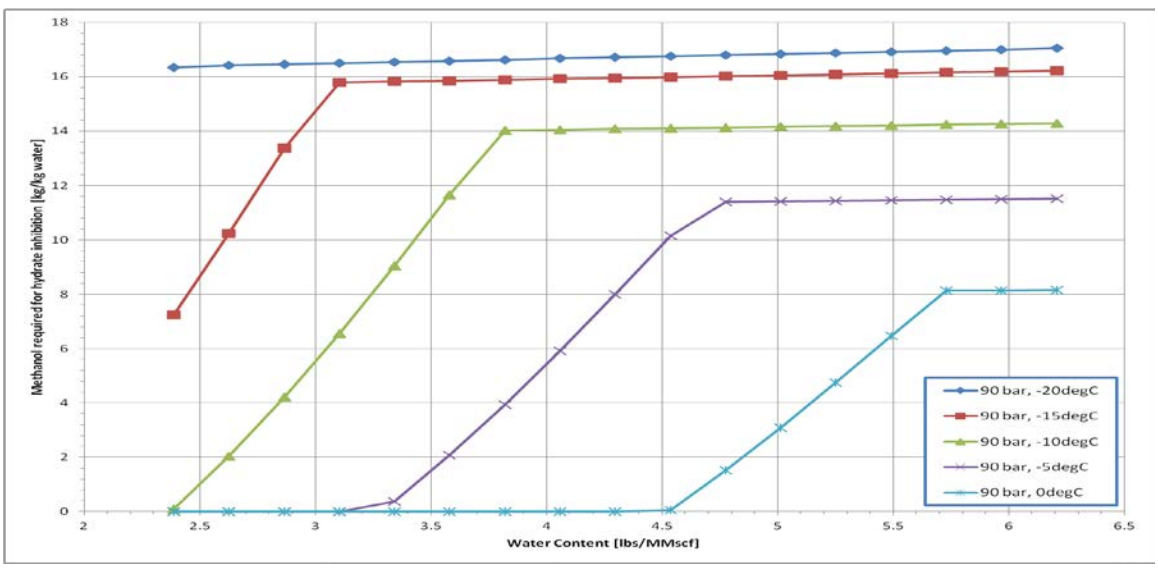

Figure 4.4 Methanol requirement for hydrate inhibition – Impact of temperature

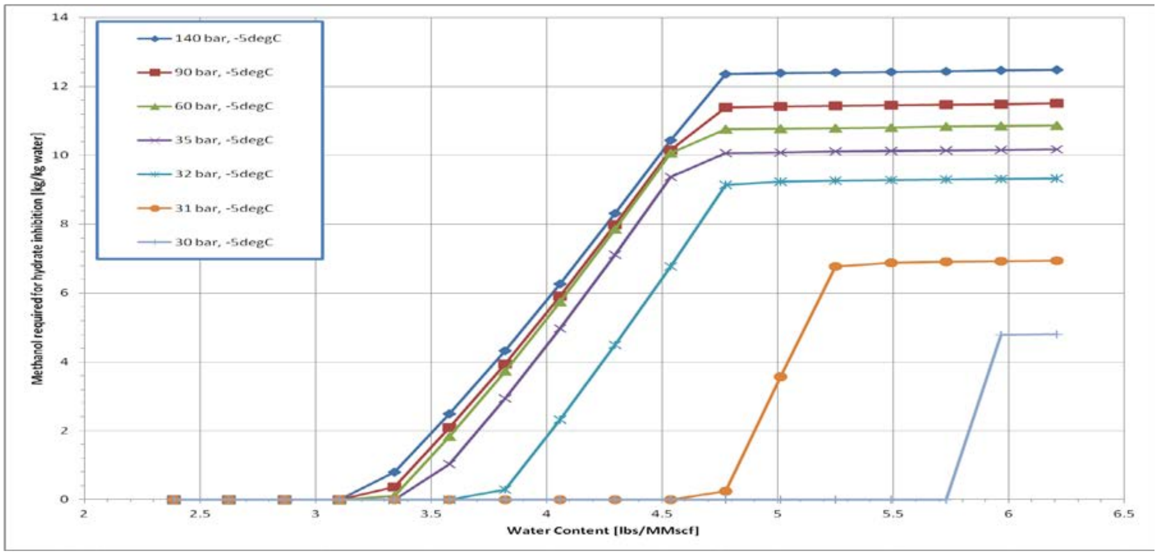

Figure 4.5 Methanol requirement for hydrate inhibition – Impact of water content

4.5. Chilly Choke

The chilly choke work was completed in the previous phase. No changes to the system the system design impact those results.

This work has been updated to include the Chilly Choke effect during initial pressurization of the flowline. This does represent the potential for cold temperatures. By maintaining a high inlet temperature, the downstream temperature can be maintained above the minimum design temperature of the pipeline.

4.6. Wax and Pour Point

There are no wax are pour point issues with the injection fluid.

4.7. Asphaltenes

There are no asphaltene components in the injection fluid.

4.8. Scale

Scale is not expected to be an issue. The injection fluid is sufficiently dehydrated that no free water exists in the system.

4.9. Well Details

Since the Select phase, the well tubing was decreased from 4" tubing to 3 ½" tubing. This has some impact on maximum rates into wells as detailed in the steady state results. The wells are all assumed to be completely vertical with an ID of 75.997mm (2.99").

Table 4.3 Summary of Well Depths

Well #	Well ID	Depth [m]
Well 1	103/07-11	2030
Well 2	100/08-19	2050
Well 3	102/05-35	2060

In the steady state models, a constant heat transfer coefficient of 11.36 W/m^2-K was used. In the transient simulations, a soil layer was included in the model. Table 4.3 summarizes the individual well depths. Previous modeling assumed all wells were 2000 m in depth. Although the depths a very similar, the well tubing ID was decreased from the previous work, so the previous results are not generally applicable. The steady state operating envelopes were updated as part of this work.

4.10. Pipeline Details

The system was modeled per the details in Table 4.4 and Figure 4.6. The well branches were not defined in detail in the previous phase. In this work, the well branches are defined in Figure 4.8.

Each of the Line Break Valves (LBVs) was included in the model along with the associated above ground section lengths as defined in Table 4.4. These sections were modeled using the given ambient temperature conditions and assuming a heat transfer coefficient consistent with a bare pipe.

Figure 4.6 shows the entire pipeline length and elevation profile along with the relevant locations of the LBVs and the well laterals. The figure also includes an artificial low spot at the river crossing that was not included in the flow assurance modeling. Figure 4.7 shows the surface layout of the pipeline.

Table 4.5 details the pipeline volumes for each segment. This information is used in subsequent sections to provide a simple means of estimating the time required to pressurize and depressurize the pipeline and serve as means of checking the more detailed flow assurance model predictions.

Table 4.4 Pipeline and Branch details (4)

	Main Trunk Line	Well Branches
Diameter-OD [mm]	323.9	168.3
Diameter-ID [mm]	299.7	146.3
Wall Thickness [mm]	12.1	11
Minimum Burial Depth [m]	1.5	1.5
Average above ground length at LBV or well pads	20	25

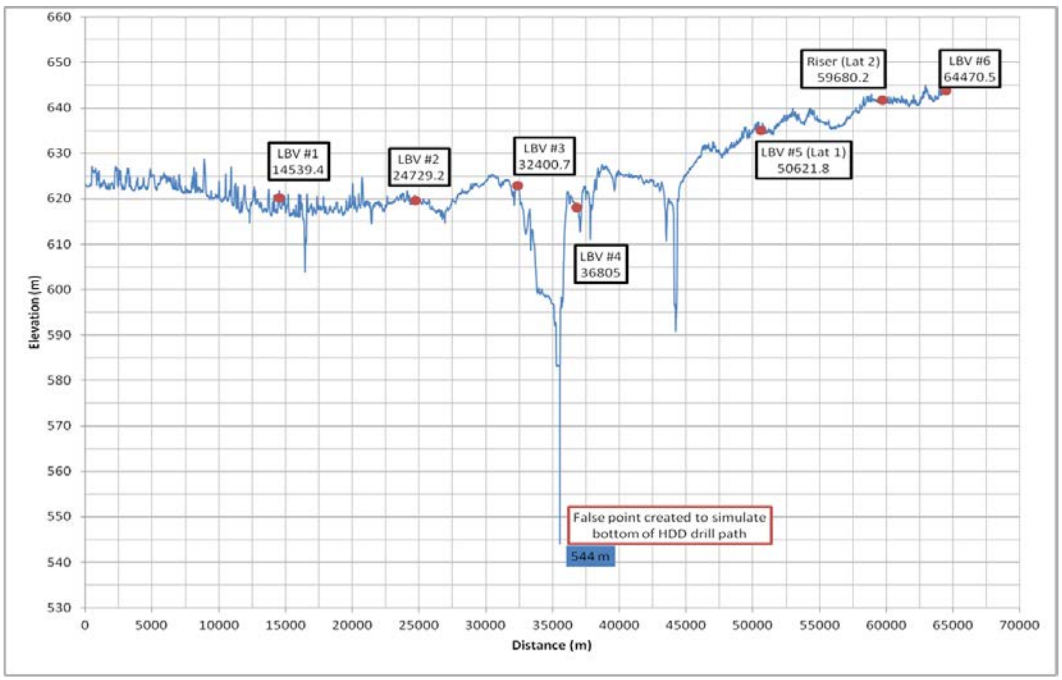

Figure 4.6 Detailed pipeline topography with location of LBVs and well branches

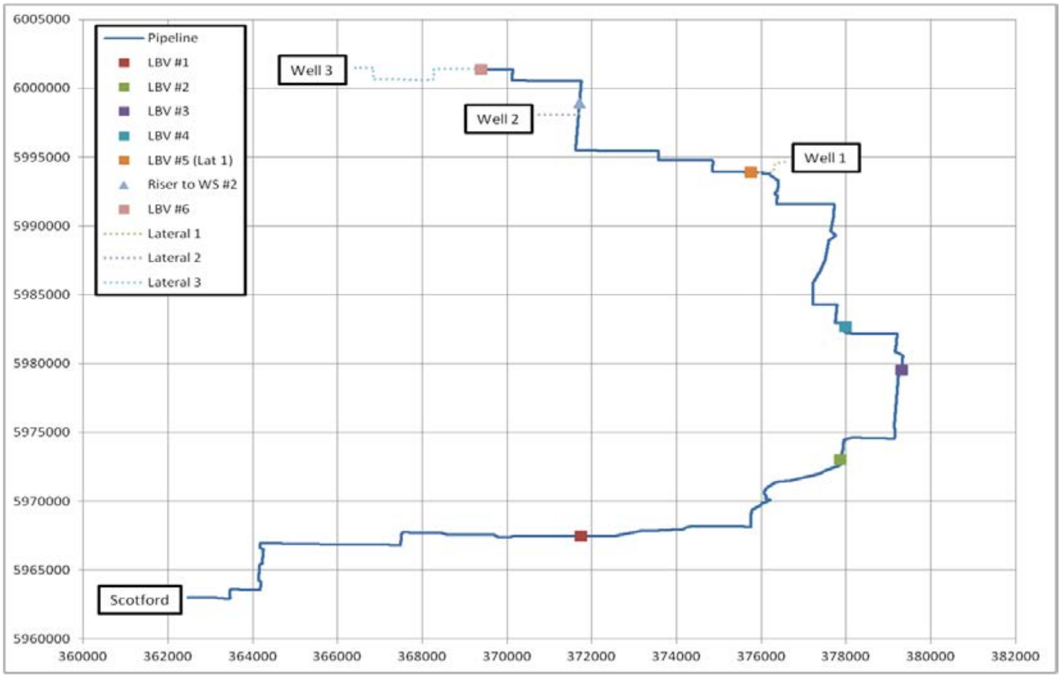

Figure 4.7 Pipeline layout with location of wells

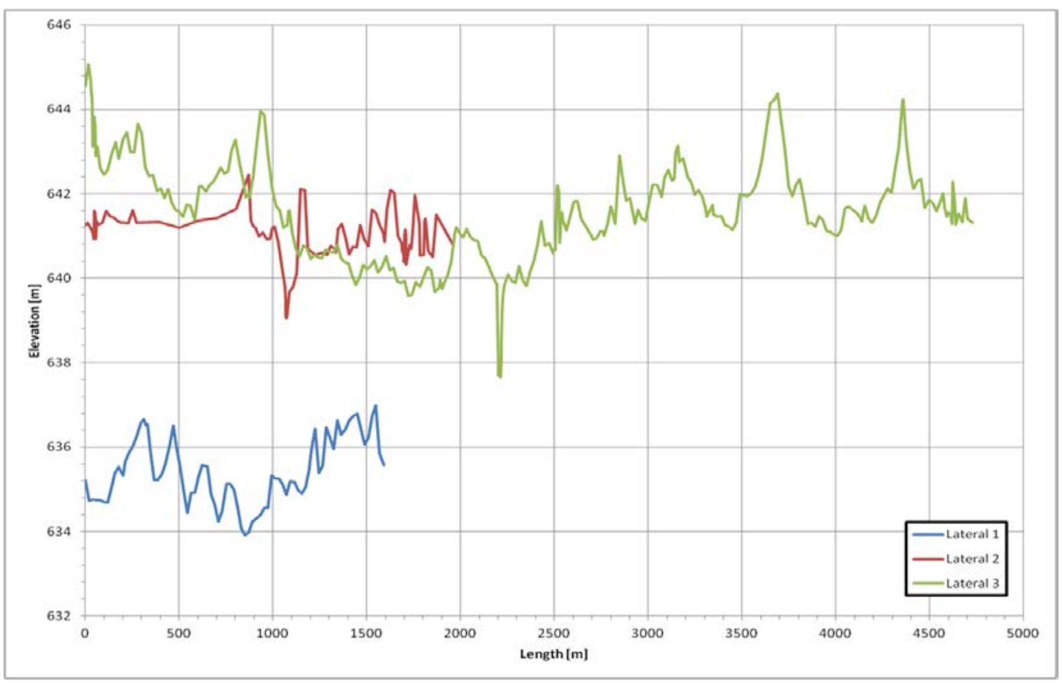

Figure 4.8 Well lateral elevation profiles

Table 4.5 Summary of pipeline segment lengths and volumes

	Length [m]	Elev Change [m]	ID [mm]	Volume [m3]
Scotford-LBV#1	14,539	-2.88	299.7	1,026
LBV#1-LBV#2	10,190	-0.65	299.7	719
LBV#2-LBV#3	7,672	3.28	299.7	541
LBV#3-LBV#4	4,404	-4.73	299.7	311
LBV#4-LBV#5	13,817	16.96	299.7	975
LBV#5-WS#2	9,058	6.65	299.7	639
WS#2-LBV#6	4,790	2.11	299.7	338
Lateral 1	1,590	0.37	146.3	27
Lateral 2	1,962	-0.49	146.3	33
Lateral 3	4,727	-3.25	146.3	79
TOTALS:	**72,750**			**4,687**

Table 4.6 Summary of pipeline operating conditions (4)

	Winter Conditions	Summer Conditions
Pipeline Inlet Temperature [degC]	43	49
Operating Pressure [barg]		
Normal Min	80	80
Normal Max	110	110
Maximum Design	140	140
Flow rate	Rated Capacity	Turndown
Flow into pipeline [kg/hr]	152,207	45,662
3 wells operating [kg/hr/well]	50,736	N/A
2 wells operating [kg/hr/well]	76,104	N/A
1 well operating [kg/hr/well]	120,497	45,662
Ambient Temperature [degC]	-40	35

Ground Temperature at pipeline burial depth [degC]	0	11
Heat Transfer Coefficient [BTU/hr-ft2-F]		
Minimum	0.35	0.35
Maximum	1.0	1.0

4.11. Production Function

A production function was not assumed in this work. The CO_2 was assumed to be injected at a rate of somewhere between the extremes defined in Table 4.6. Where appropriate, a range of flow rates were used to capture the complete operating envelope. The operating procedures have not been developed as to define injection rates into individual wells as there is still some uncertainty on the individual well injectivity values.

5. STEADY STATE ANALYSIS

5.1. Wells

The injection of CO_2 into the wells is constrained by the bottomhole pressure requirement that the pressure should not exceed the fracture pressure of the reservoir. For a given injection rate and reservoir injectivity, the resulting bottomhole pressure can be determined as shown in Figure 5.1 Note that at the lowest expected injectivity value, the maximum injection rate is ~105,000 kg/hr. At any rates larger than this, two injection wells would be required. The reservoir injectivity value needs to be greater than 350 m^3/d/MPa to achieve the maximum desired single well injection rate of ~120,000 kg/hr.

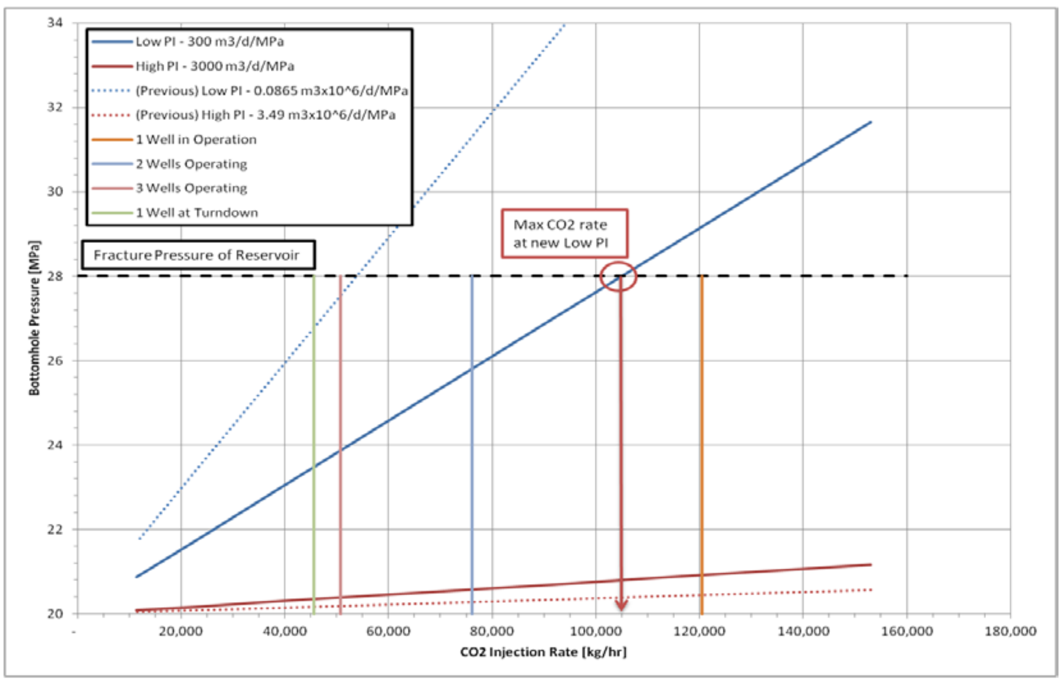

Figure 5.1 Maximum injection rate based on fracture pressure of reservoir

The updated injectivity values(7) are specified based on a liquid water injection rate. The CO2 density varies much more than water, so it is possible to get a wider variation in mass flow rates when using the CO_2. At colder temperatures (winter operation) the CO_2 density is higher, meaning that for a given volumetric rate, the mass rate will be higher. Figure 5.2 shows the impact that changing the temperature has on the CO_2 injection rate. Note that in this a range of 0°C (winter) and 24°C (maximum based on Figure 5.7) the maximum CO_2 injection rate varies by about 10% at the lower injectivity value. Note that the composition of the injected fluid can also decreases the maximum rate due to the decrease in fluid density and the expanded region of gas breakout.

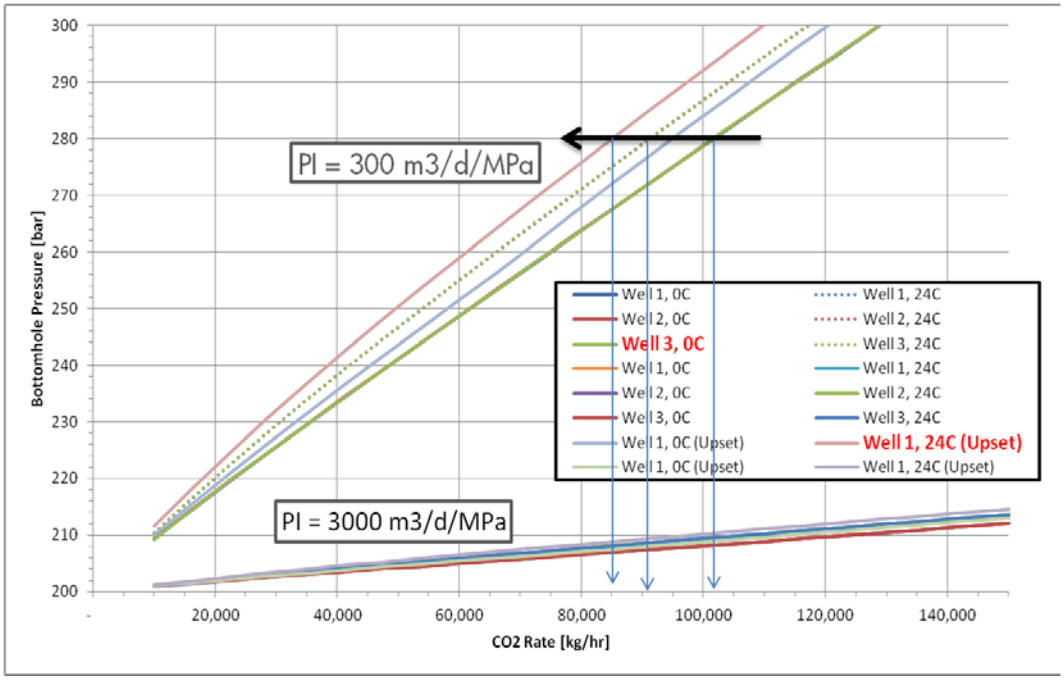

Figure 5.2 Impact of temperature on CO_2 injection rate

5.2. Pipeline

5.2.1. Wellhead Pressures

In the previous work, numerous sensitivities were done to quantify the most important parameters in the pipeline modeling. This has more impact in the transient analysis, but also plays a role in the steady state results. Figure 5.3 and Figure 5.4 show the range of expected wellhead pressures based on sensitivities in the temperature modeling. The minimum and maximum values represent the range of expected compressor discharge temperatures, ambient temperatures, and soil properties. Similarly, Figure 5.5 and Figure 5.6 show the impact on wellhead pressure due to the fluid composition. At low pressure (85 bar), the variation in wellhead pressure can be substantial, while at the higher pressure (130 bar), the variation is not significant. Based on this, the higher pressure operation is recommended until proper benchmarking of the models can be completed with operational data, after which the compressor discharge pressure can be optimized.

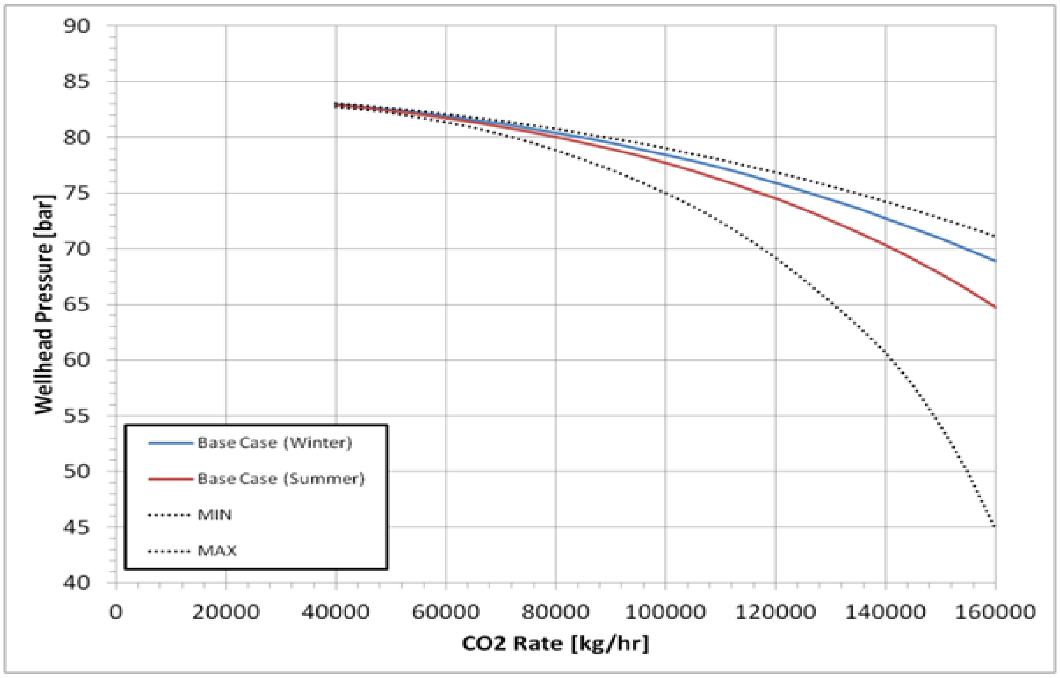

Figure 5.3 Range of Wellhead pressures expected at low pressure operation

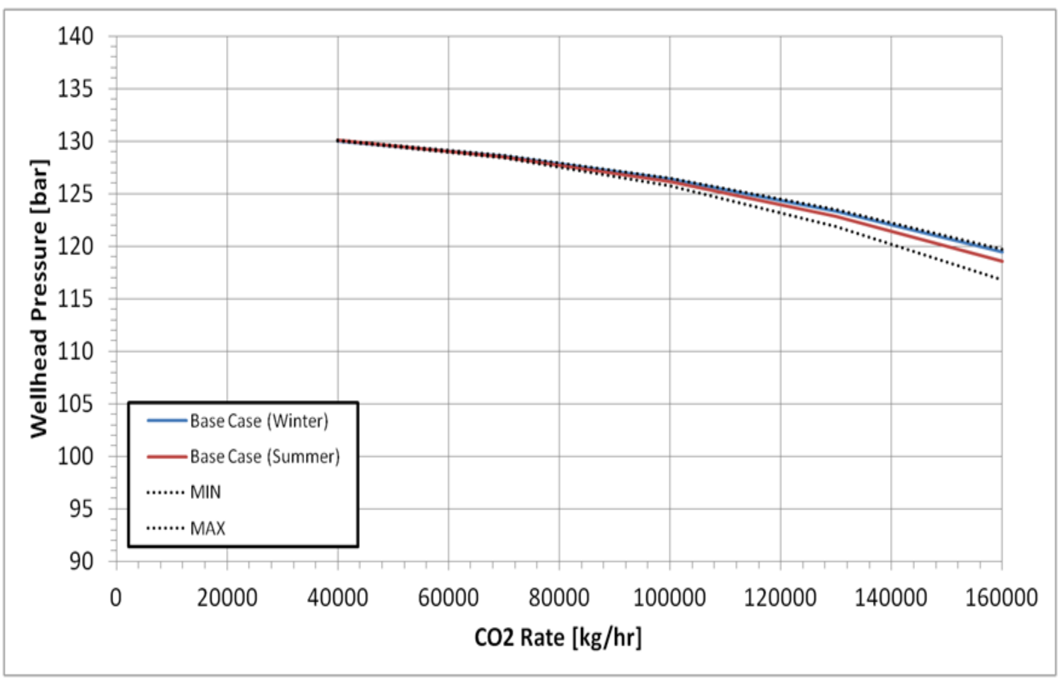

Figure 5.4 Range of Wellhead pressures expected at high pressure operation

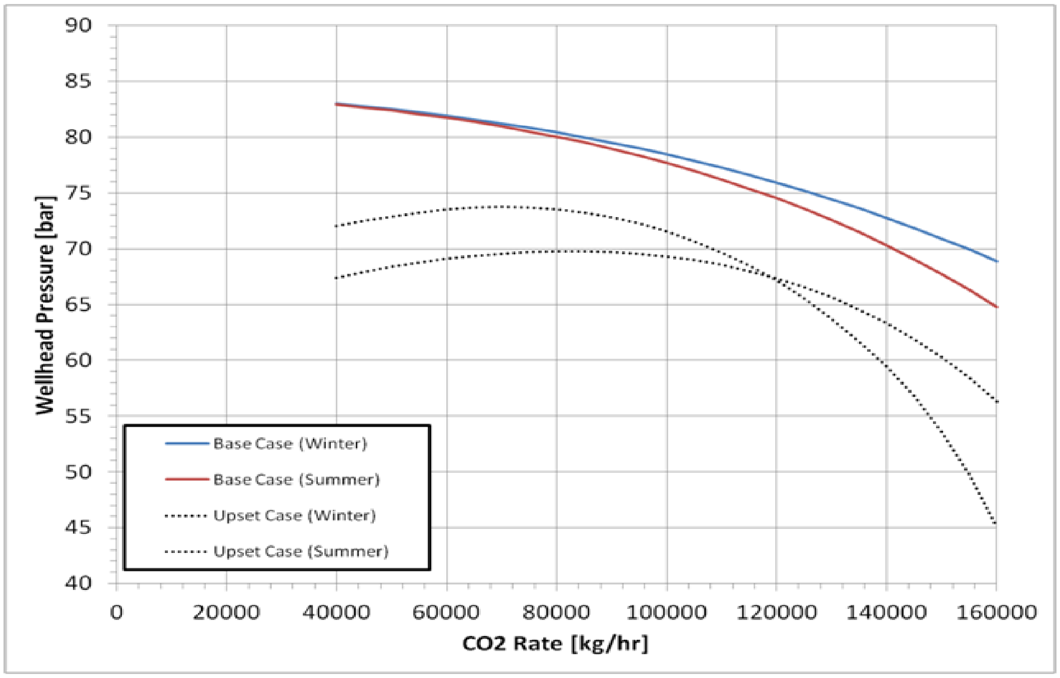

Figure 5.5 Range of Wellhead pressures expected at low pressure operation due to composition variability

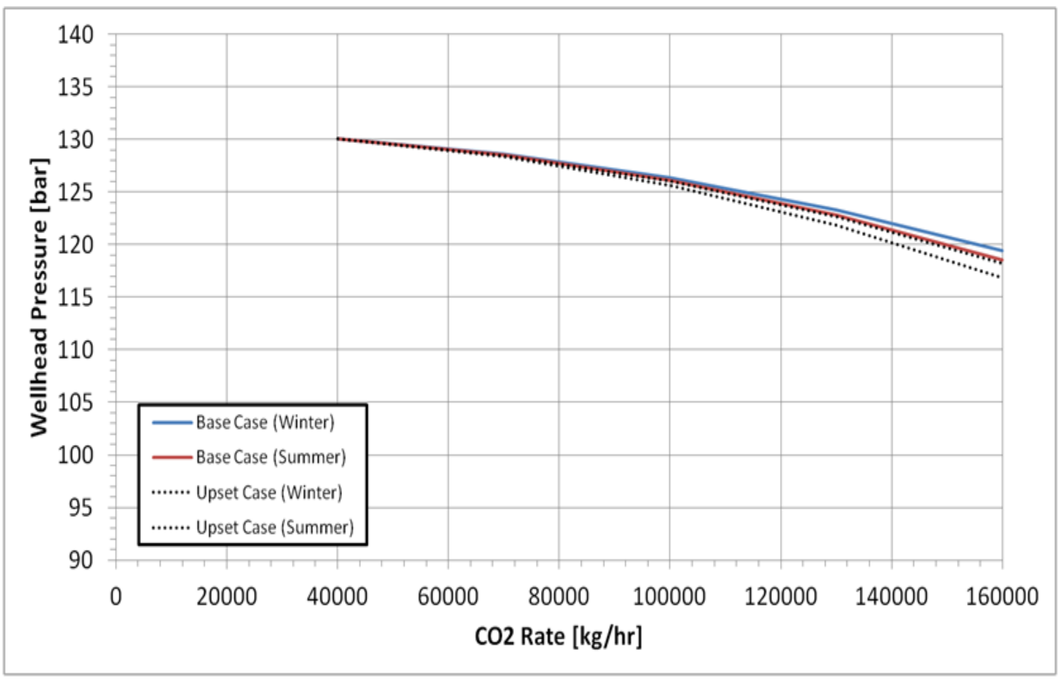

Figure 5.6 Range of Wellhead pressures expected at high pressure operation due to composition variability

5.2.2. Wellhead Temperatures

The flowing wellhead temperatures are also still uncertain due to uncertainties around the actual compressor discharge temperature and pressure, soil properties, and wide range of possible flow rates in each well. Figure 5.7 shows the anticipated wellhead temperatures for a number of different assumptions. At higher flow rates and lower operating pressures, the wellhead temperatures tend to be higher. Note that for a given mass rate, the volumetric rate of CO_2 is greatest at high temperature and low pressure. All figures are based on mass rates, but given the high variability in the CO_2 density, this translates to a larger range of volumetric rates.

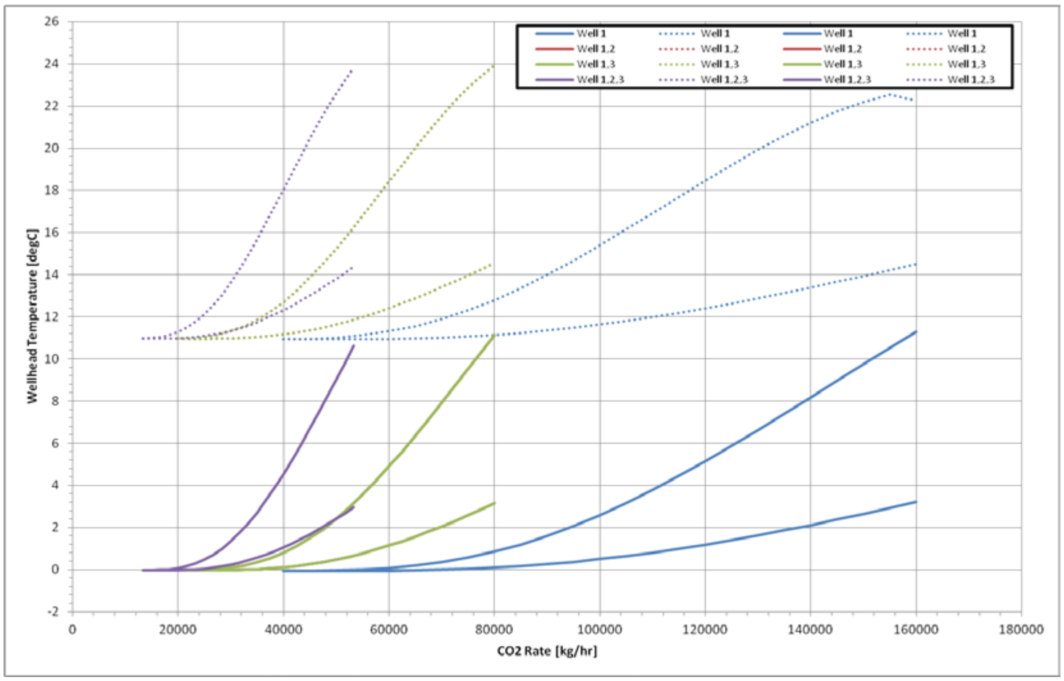

Figure 5.7 Range of possible flowing wellhead temperatures for Well 1

5.3. Operating Envelopes

This section defines the operating envelope for injection of CO2 into the wells. The operating envelope is mainly defined by the compressor discharge pressure, the desired injection rate, and the ambient conditions, and the injectivity of the reservoir. Figure 5.8 shows a typical operating envelope, for a compressor discharge pressures near the min and max values. Note that the there is not a large pressure drop in the pipeline over the range of typical injection rates. There is not a lot of variation in wellhead pressure depending on whether 1, 2, or 3 wells are used.

There is however a large range of wellhead pressures associated with injection into the well. In turn, these pressures depend significantly on the wellhead temperature and the reservoir injectivity values. Based on this analysis, the most favorable injection occurs at lowest temperatures (due to the higher density of the CO_2). In the best case scenario, the maximum injection rate into a well is ~115,000 kg/hr. The pipeline and lateral is designed for 120,497 kg/hr. Therefore, the maximum injection rate into a single well is likely determined by the available wellhead pressure and not throughput limitations in the pipeline or lateral.

The temperature also plays a role in the injection rate into a well. Based on the previous section, a fairly broad range of wellhead temperatures was observed. If the highest temperature observed (24°C) is used, Figure 5.8 shows that it is not possible to operate two wells during summer conditions if the reservoir injectivity is low and the use of all three wells is required. But if the reservoir injectivity is at the higher end, then it is possible to use two wells and the compressor discharge pressure can be operated at about 115 bar.

Figure 5.9 is similar to Figure 5.8 except that the curves for 11°C wellhead temperature were included. The 11°C curves are more generally applicable during summer operation, which means that the operating envelope is expanded, although it is still not possible to injection using only two wells if the reservoir injectivity value is at the low end of the expected range.

Figure 5.10 includes the results from an integrated well and pipeline model. The previous figures were generated using a separate well and pipeline model. The integrated model is more accurate, in that it includes the possibility of JT-cooling across the wellhead choke, should a pressure drop be required at the wellhead. In general, the results compare very favorably with the independent well and pipeline models. In this model, the biggest source of uncertainty is the overall heat transfer coefficient between the pipe and the soil, which is controlled by the effective thermal conductivity of the soil and is currently unknown. During summer operation, this can impact the injectivity by about 10,000 kg/hr. This will have an impact on the compressor discharge pressure required, particularly during summer operation with two wells.

To avoid any such issues, it is recommended to begin operations with a high compressor discharge pressure and to operation using all three injection wells. After initial startup, benchmarking of the models is required to determine these unknown parameters that impact the operating envelope. Once this benchmarking is completed, then the system can begin optimization of the number of injection wells and the compressor discharge pressure.

Figure 5.11and Figure 5.12 show similar operating envelopes for wells 2 and 3 to those discussed for well 1. The well performance curves are nearly identical because all the wells have similar depths. The pipeline pressures drop for wells 2 and 3 some differences from well 1 due to the longer pipeline lengths, but even then, the difference in pressure drop is small between all the cases.

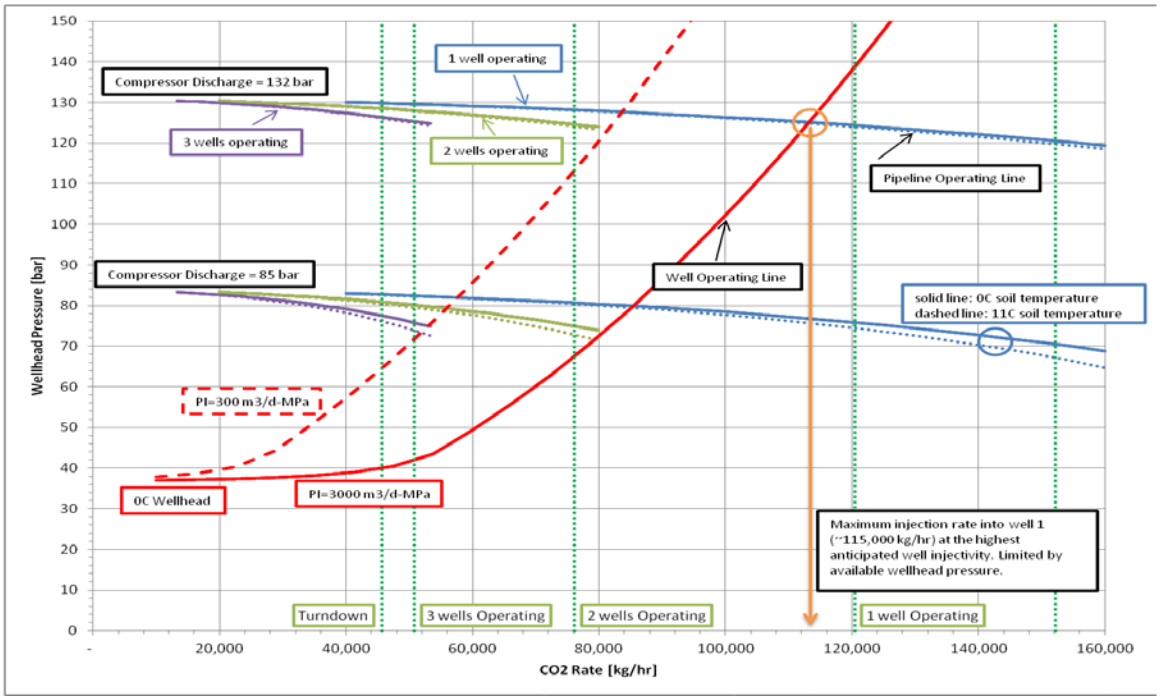

Figure 5.8 Steady state results for injection into well 1 (1,2, or 3 wells operating)

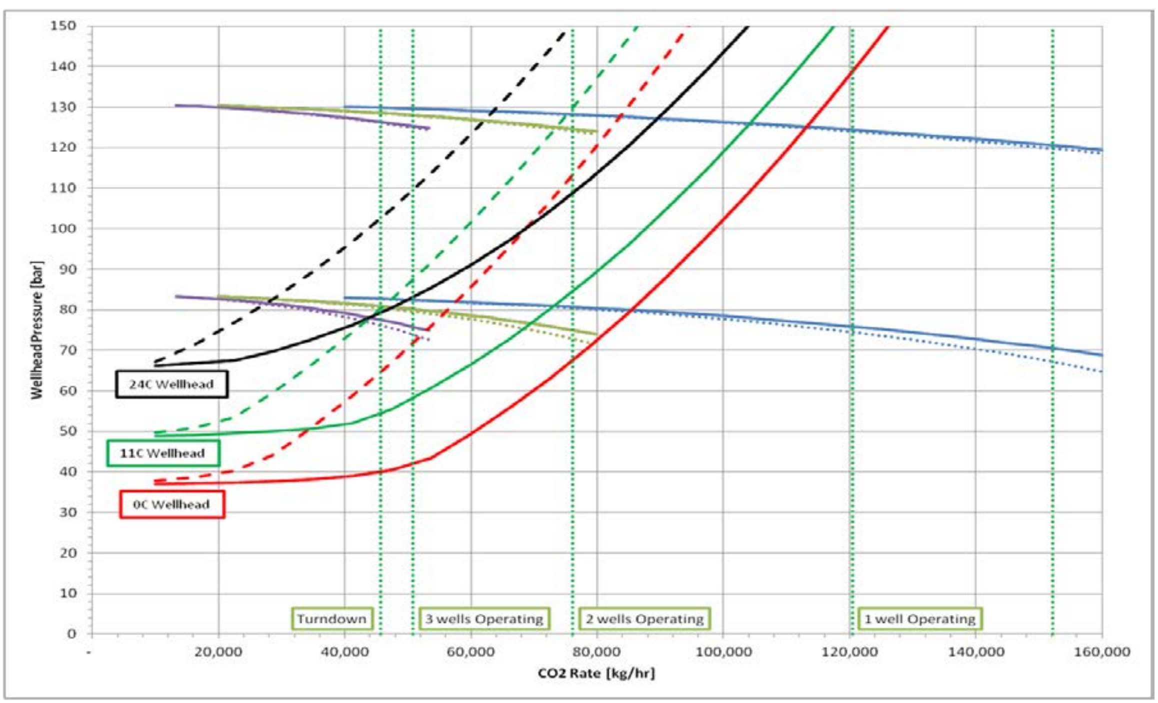

Figure 5.9 Steady state results for injection into well 1 (1,2, or 3 wells operating), including 11C wellhead temperature

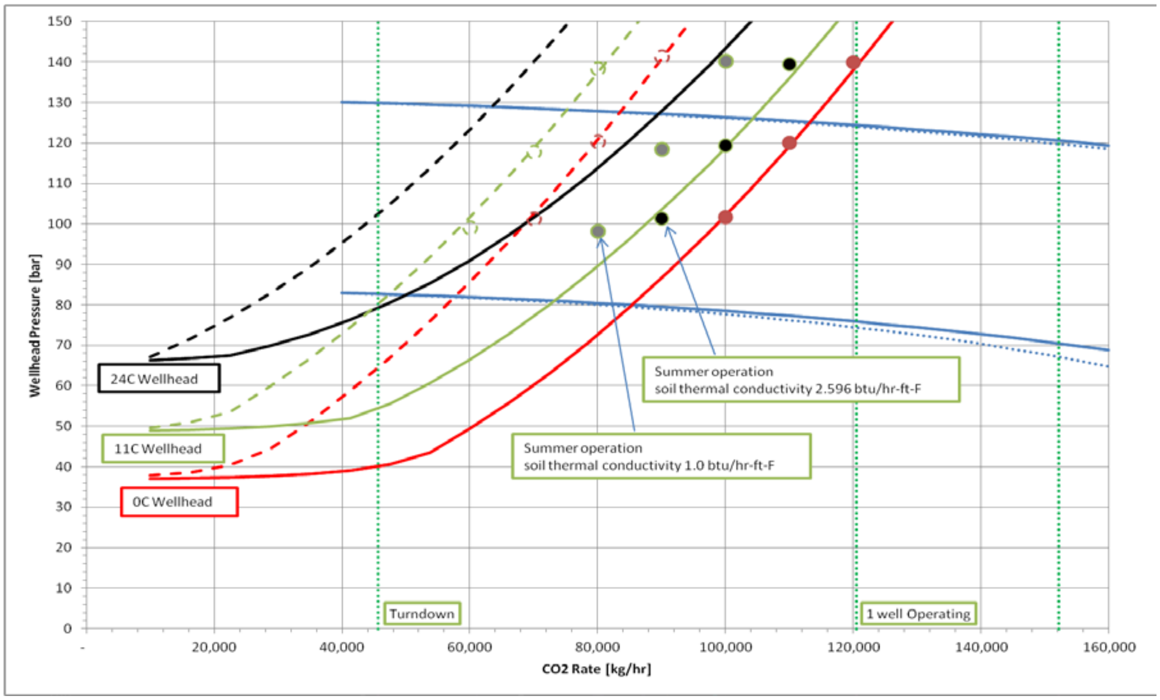

Figure 5.10 Steady state results for injection into well 1 (1,2, or 3 wells operating) including results from integrated pipeline/well model

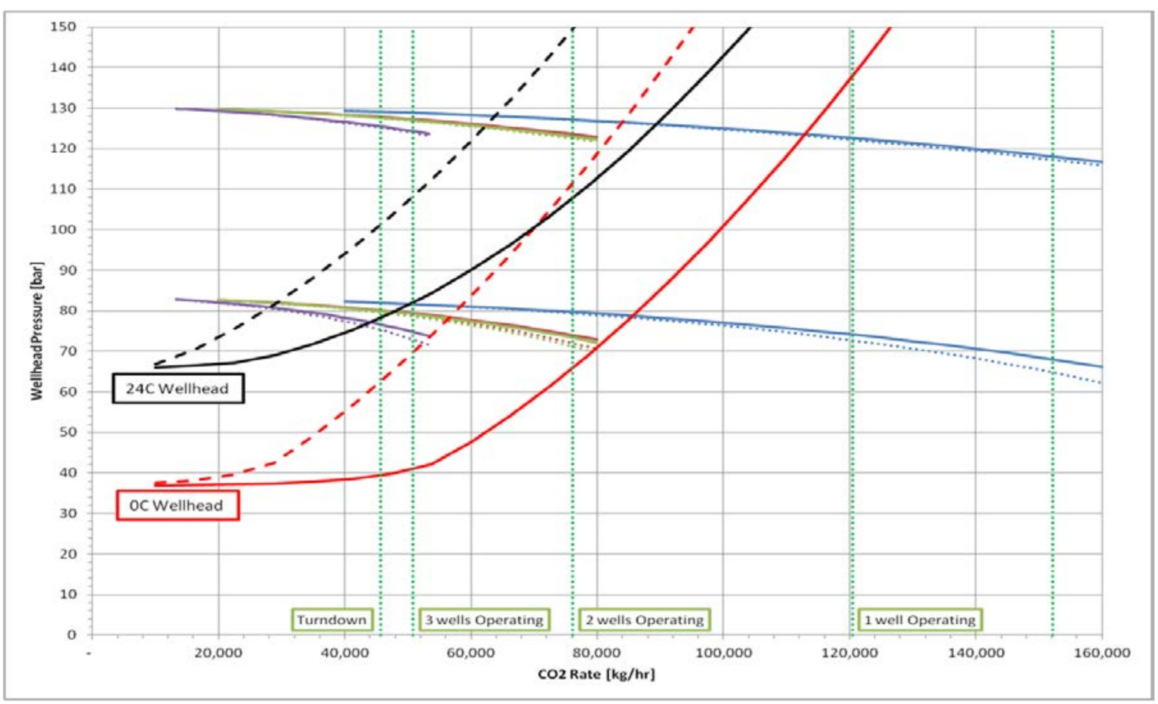

Figure 5.11 Steady state results for injection into well 2 (1,2, or 3 wells operating)

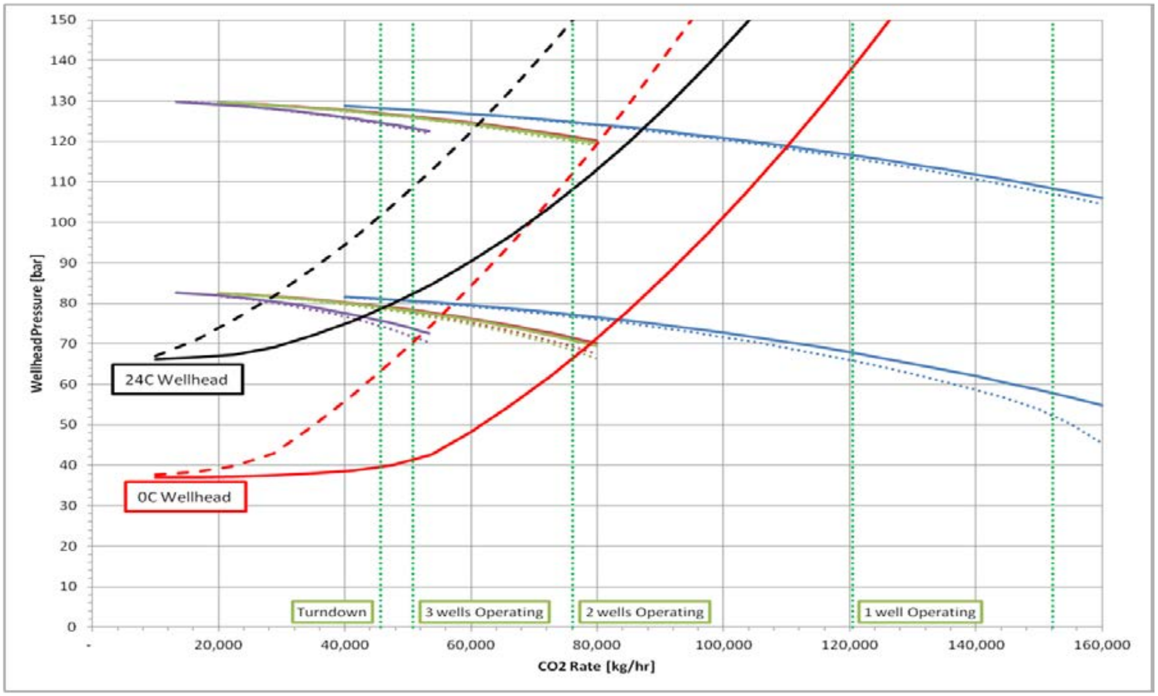

Figure 5.12 Steady state results for injection into well 3 (1,2, or 3 wells operating)

6. TRANSIENT ANALYSIS

The previous sections detailed the steady state operating envelope. This section looks at transient events, and particularly the temperature and pressure response of the system during startup and shutdown type operations.

6.1. Initial Line Fill

In the previous phase, work was done to simulate what was to be expected during line filling operations, from a low pressure (single phase gas). Two issues were identified that needed further study, namely the pressure response of the system during line filling and the potential for low temperatures. The pressure response of the system is more for operator awareness and does not have an impact on how the system will be operated. The cold temperatures, however, have a significant impact on how the system will be operated, particularly when filling the pipeline from an initial state containing a gas (either low pressure N_2 or CO_2).

The pressure response of the system is due to the complex interaction of the CO_2 phase behavior and the heat transfer characteristics of the system. A details ambient temperature profile and soil thermal conductivity values are unknown and will not be known until the system begins operating. Figure 6.5 details the pressure response at each location where pressure is likely to be measured during operations. In all cases, the pressure increases relatively fast from the initial state (1 or 5 bar) up to the two-phase (vapor-liquid equilibrium (VLE) condition. This pressure depends on the temperature and given that the temperature varies from the compressor outlet temperature to the ambient soil temperature, there can be a large variation in the VLE conditions. This is to say that the pressure will remain relatively constant for a considerable amount to time, which depends on the compressor discharge rate. Once the pressure reaches about 60 bar, further injection of CO_2 results in a relatively rapid pressure increase.

Note that some of the pressure predictions in the model show a slight decrease. These are also accompanied by pressure spikes, which are due to instabilities in the model. These instabilities are caused by the strong coupling of the temperature and pressure at the phase boundary. It is likely, but not confirmed that the pressure decreases could be a result of the model, and not a real phenomena. During the filling process, the inlet pressure appears to remain relatively stable and does not show any of these instabilities.

Figure 6.6 shows the inlet pressure response for several different filling rates. The general response is similar in each case, in that the pressure increases rapidly to about 40 bar, then remains there for some time. Once the pressure reaches about 60 bar, there is a rapid increase in the pressure beyond that. Note that these curves were determined with a constant mass source. The actual compressor discharge rate depends on the system pressure, so above 60 bar, the rate should decrease and the rate of pressure increase will not be as fast. It's still recommended that the compressor discharge rate be reduced once the pressure increases above 60 bar to minimize the potential to exceed the high pressure set point.

The other issue identified was cooling at the pipeline inlet due to the initially low pressures. Depending on this initial pressure and temperature, the compressor discharge pressure and temperature, the potential for pipe wall temperatures less than the rating of the pipe (-40°C) is possible. Figure 6.1 shows the fluid temperature at the start of the pipeline for a number of different potential startup cases. Note that in some cases cold temperatures (<-40°C) are possible for extended periods of time. Figure 6.2 shows a similar plot, but for the pipe wall temperature, which is of more interest. Note that the pipe wall temperatures in all but two of these scenarios remains above -40°C. Note that the Minimum Design Metal Temperature (MDMT) is -45°C. In this work, a value of -40°C was used as the target to allow for some safety factor in the design.

Figure 6.2 indicates that the worst case occurs at lower compressor discharge pressures. This is in part due to the resulting rates into the pipeline, as shown in Figure 6.3. At lower pressures, the rate is lower, which means it takes longer to pressurize the pipeline and the colder temperatures persist for a longer period of time, thus allowing the pipe wall temperatures to equilibrate with the fluid temperatures. If the system is pressurized quickly, the pipe wall temperatures do not have sufficient time to cool before the fluid temperatures begin to increase. Figure 6.4 shows the minimum pipe wall temperatures along the length of the pipeline while pressurizing the system. At lower compressor discharge temperature, the cold temperatures can exist for a considerable distance downstream of, even at higher initial pressures. If the compressor temperature is increased, the coldest pipe wall temperatures are isolated to a much smaller distance downstream of the compressor.

Based on these results, it is recommended that the compressor be operated at as high of a temperature as possible and maintain a lower compressor outlet pressure. The higher temperatures were effective at keeping the pipe wall temperatures above -40°C at the low compressor discharge rates. If possible, the compressor should be ramped up as quickly as possible to minimize the amount of time the system remains at lower pressures.

It is also possible to pressurize individual sections of the pipeline, between LBVs.. This would be beneficial for the section from Scotford to LBV1 in that this section could be pressurized quickly and minimize the potential for cold temperatures in that section. However, all other sections downstream of LBV1 there would be less control of the temperature downstream of the LBVs. When these LBVs are opened, there would be a pressure differential across the valve resulting in cold temperatures downstream of the valve. Unlike the conditions at the compressor discharge, there would be no control on temperature or rate when opening these LBVs. Based on the modeling, the low temperatures can be controlled, so it is recommended to pressurize the entire pipeline up to the wellhead valves at the same time.

Similarly the analysis can be done using the pressure/enthalpy diagram for CO_2 to identify the operating envelope bases on the fluid temperature (see Figure 6.7). In order to maintain the downstream temperature of the fluid above -40C, the figure can be used to determine the required upstream conditions assuming the cooling in the system is related to an isenthalpic expansion of the fluid. At these conditions, the Figure 6.7 shows that the upstream pressure required at 40°C is about 55 bar and at 60°C is about 80 bar. Note that given the shape of the isotherms in the figure, the final temperature of the fluid is very sensitive to the upstream conditions. The curves shown in Figure 6.1 are generally consist with the pressure/enthalpy diagram although the two figures were generated using different PVT packages, which results some differences, due to the sensitivity of the enthalpy.

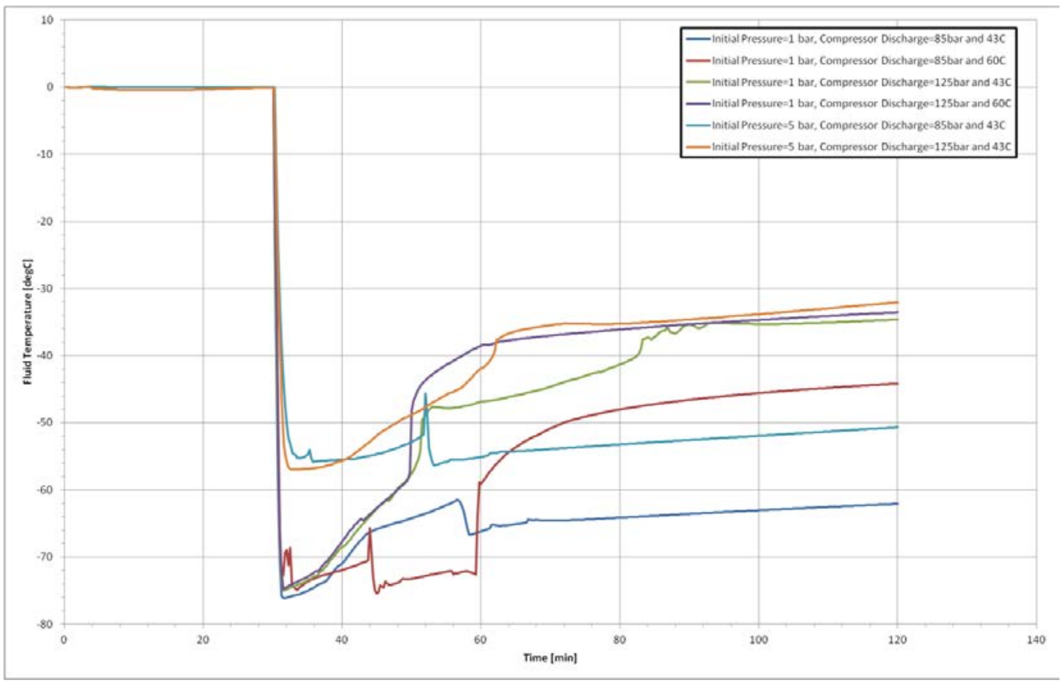

Figure 6.1 Fluid temperature downstream of compressor during pressurization of pipeline from low pressure condition

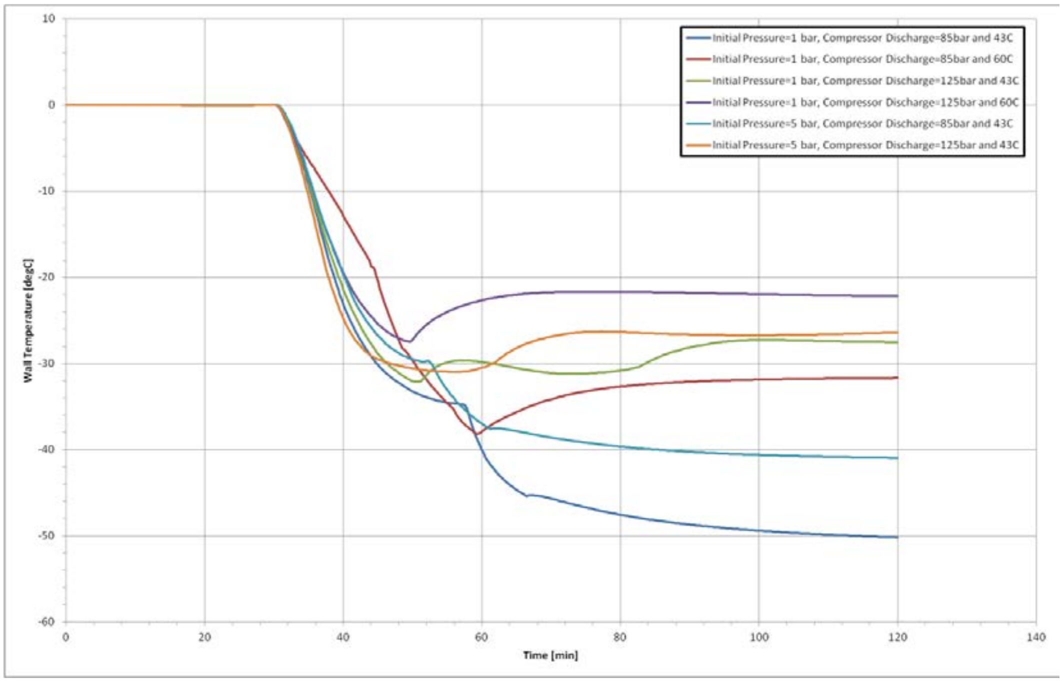

Figure 6.2 Wall temperature downstream of compressor during pressurization of pipeline from low pressure condition

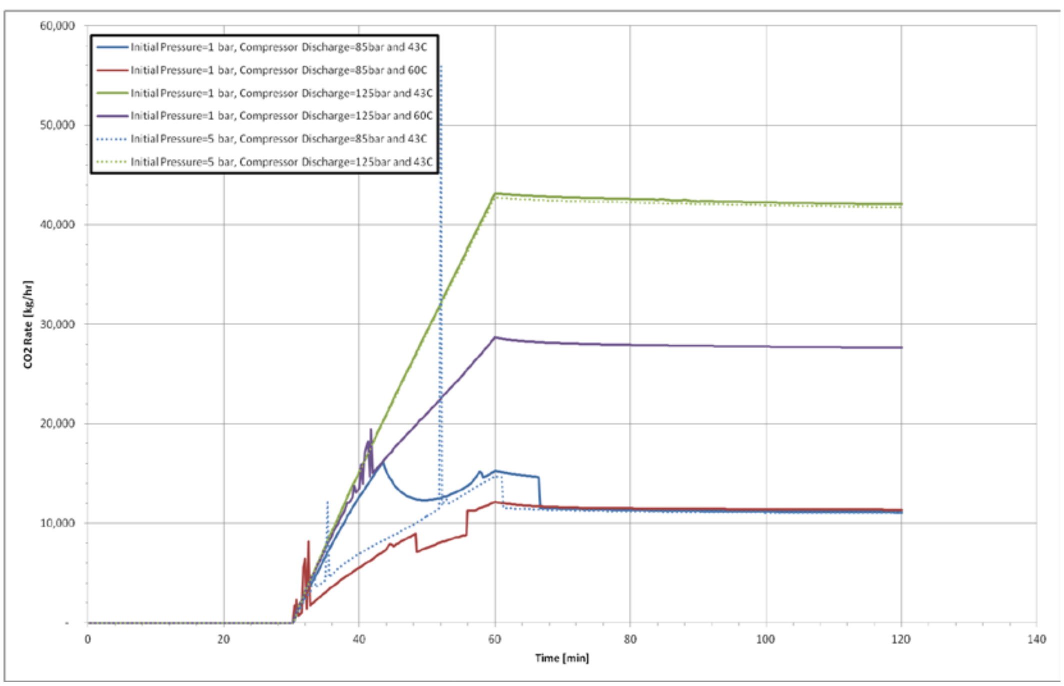

Figure 6.3 Injection rate of initial line fill in determining initial temperatures

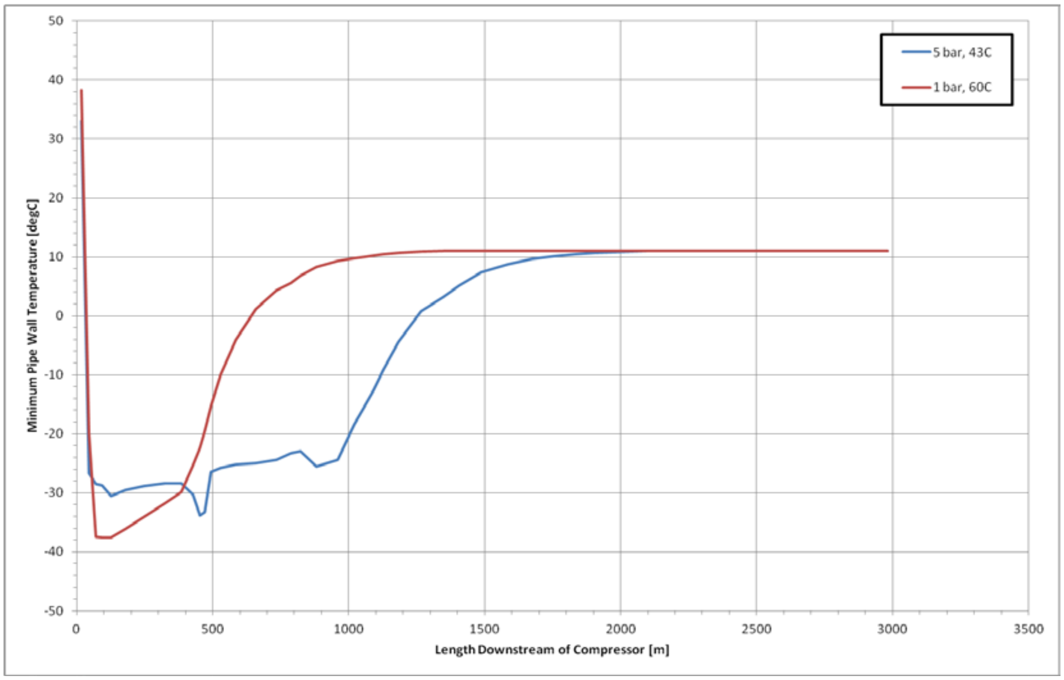

Figure 6.4 Minimum pipe wall temperature along pipeline during initial line fill

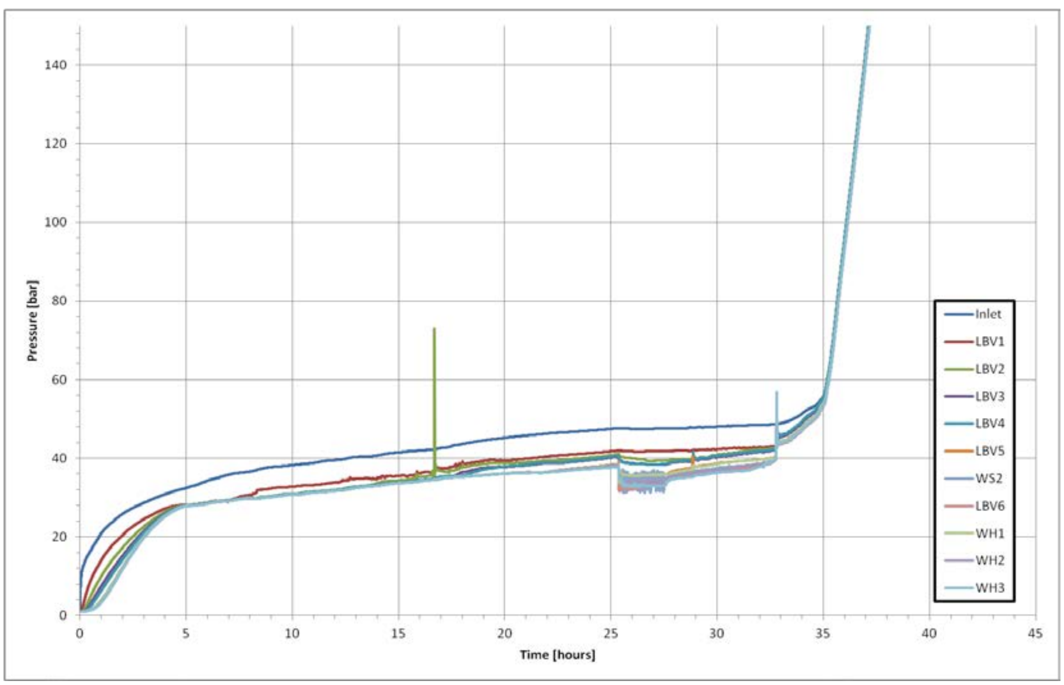

Figure 6.5 Pressure increase with time during initial line fill (120,497 kg/hr)

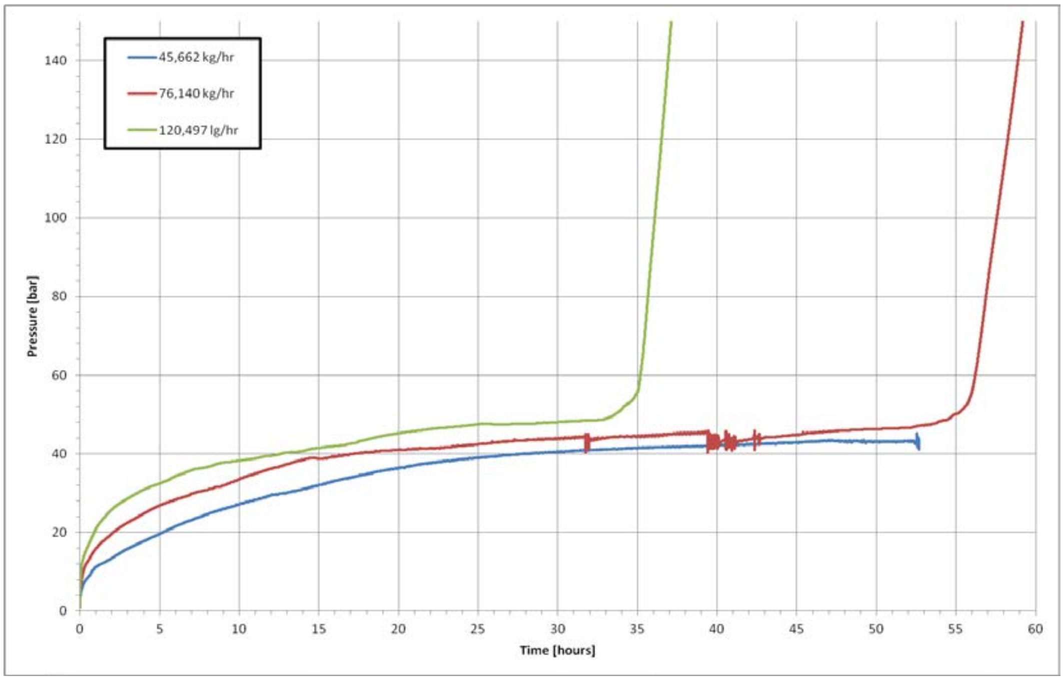

Figure 6.6 Inlet pressure increase with time during initial line fill at various rates

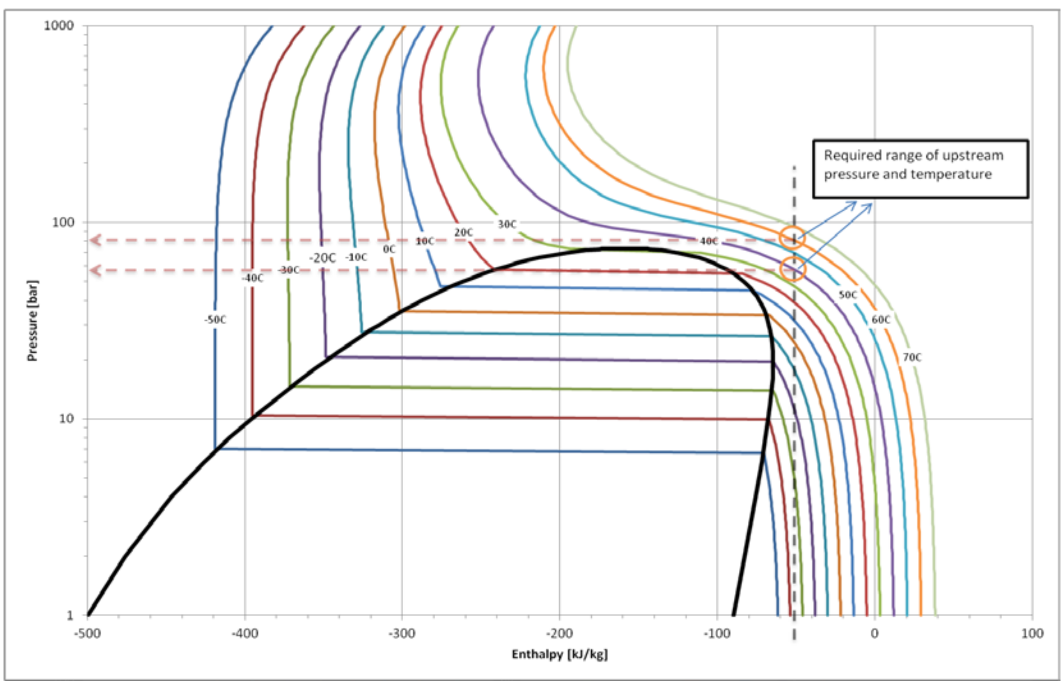

Figure 6.7 Pressure/Enthalpy diagram for CO_2 (generated using Multiflash v4.2)

6.2. Pressure Increase due to a Compressor Restart

A restart of the system addresses the issue of pressure increase due to the timing of starting the compressor versus the opening of the wellhead choke(s). If a compressor restart occurs prior to the opening of the wells, the pressure in the pipeline is expected to increase, which is not an issue until the high pressure set point of the compressor is reached. The work was to identify the amount of time available after a compressor restart before the well(s) need to be opened.

It is assumed that the compressor will initially begin operating at the turndown rate until the wells have been properly opened, at which time the compressor will be ramped up to the desired rate. Figure 6.8 shows a typical set of results for a restart. The system pressure increases somewhat linearly meaning that this curve can easily be shifted up or down based on the initial pressure in the pipeline. For an initial pressure of 100 bar, it takes about 3 hours before the high point setting of the compressor is reached. At higher initial pressures or higher injection rates, the high point setting will be achieved sooner.

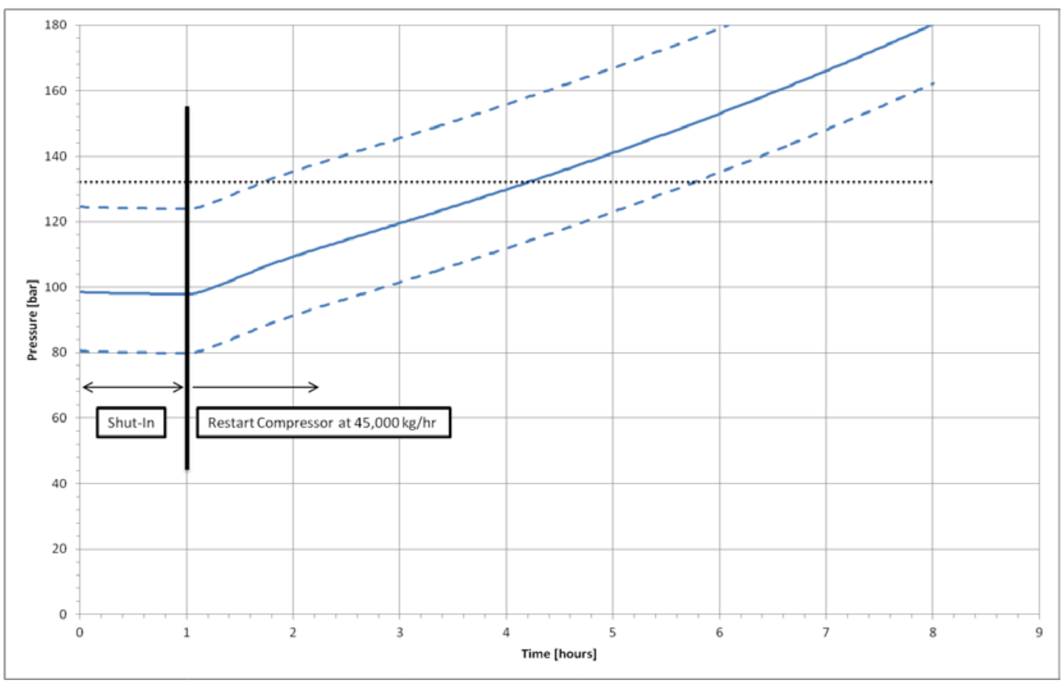

Figure 6.8 Pressure increase at startup at turndown rate (45,000 kg/hr)

6.3. Line Packing due to Well Shut-in

There is also a case that the line pressure can be increased to the high pressure set point if the wells are closed, but the compressor is still running. There was also a concern of an increase in pipeline pressure if one or two of the wells trips closed, but the compressor output is not changed.

Table 6.1 details a simplified analysis of the amount of time it takes to increase the pressure in the flowline due to a constant mass source/output. Based on the pipeline volumes and the average density of the CO_2, a simple estimate of the time to linepack the system can be calculated. These values are not meant to be definitive as the constant density (i.e. temperature and pressure) assumption is not valid. But the intent of these value is to give an initial guess of the time and it is much easier to quantify the effects of different scenarios, such as one or two wells shutting-in and not all three.

Note that these results all assumed constant temperatures and rates. The actual system will have a wide range of temperatures along the length of the pipeline and the rate will vary as the pressure changes. Nevertheless, the times in the table give a rough approximation of the reaction time available during a well shut-in, particularly if it is an unplanned shut-in. The table shows that the amount of time is significantly more during summer operations (i.e. high ambient temperature). At high operating pressures, the amount of time available is on the order of an hour or less and could be as little as about 15 minutes if this case occurs when all three wells shut-in.

Table 6.1 Simplified estimate for time to pack pipeline

	80 bar, 0C	120 bar, 0C	130 bar, 0C	140 bar, 0C	80 bar, 27C	120 bar, 27C	130 bar, 27C	140 bar, 27C
Density [kg/m3]	962	985	990	995	753	832	845	856
	[kg]	[kg]	[kg]	[kg]	[kg]	[kg]	[kg]	[kg]
Scotford-LBV#1	986,638	1,010,229	1,015,429	1,020,413	772,508	853,844	866,511	877,814
LBV#1-LBV#2	691,476	708,009	711,654	715,147	541,405	598,408	607,286	615,207
LBV#2-LBV#3	520,585	533,032	535,776	538,406	407,602	450,518	457,202	463,166
LBV#3-LBV#4	298,874	306,020	307,595	309,105	234,009	258,648	262,485	265,909
LBV#4-LBV#5	937,603	960,021	964,962	969,700	734,115	811,408	823,446	834,187
LBV#5-WS#2	614,699	629,397	632,637	635,742	481,291	531,965	539,857	546,899
WS#2-LBV#6	325,068	332,840	334,554	336,196	254,518	281,316	285,490	289,214
Lateral 1	25,713	26,328	26,463	26,593	20,132	22,252	22,582	22,877
Lateral 2	31,732	32,490	32,658	32,818	24,845	27,461	27,868	28,232
Lateral 3	76,445	78,273	78,676	79,062	59,854	66,156	67,137	68,013
TOTALS:	4,508,832	4,616,639	4,640,403	4,663,183	3,530,280	3,901,977	3,959,864	4,011,517

Pressure Change [bar]:	80-->130	80-->140	120-->130	120-->140	80-->130	80-->140	120-->130	120-->140
Change in CO2 [kg]:	131,570	154,350	23,764	46,544	429,584	481,238	57,887	109,541

	CO2 Rate [kg/hr]	Time [hours]				Time [hours]			
	45,662	2.9	3.4	0.5	1.0	9.4	10.5	1.3	2.4
	152,207	0.9	1.0	0.2	0.3	2.8	3.2	0.4	0.7
1 Well Shut-In	152,207	2.6	3.0	0.5	0.9	8.5	9.5	1.1	2.2
2 Wells Shut-In	152,207	1.3	1.5	0.2	0.5	4.2	4.7	0.6	1.1
1 Well Shut-In	133,500	3.0	3.5	0.5	1.0	9.7	10.8	1.3	2.5
2 Wells Shut-In	133,500	1.5	1.7	0.3	0.5	4.8	5.4	0.7	1.2

Figure 6.9 shows that the results of the more details flow assurance model is broadly consistent with the simplified results in Table 6.1. In the detailed model, as the pressure in the pipeline increases, the rate into each available well continues to increase for a given wellhead choke opening, as shown in Figure 6.10. This decreases the rate of pressure increase so that in the actual scenario the line-packing times are longer than given in the simple model. In the case of low pressure operation when only one well is shut-in, the actual time to pressure the line to above the high pressure set point is greater than 24 hours. However, in the event of high pressure operation of the pipeline, the reaction time is much more similar to the simplified model in that the injection rate into the wells does not increase very quickly.

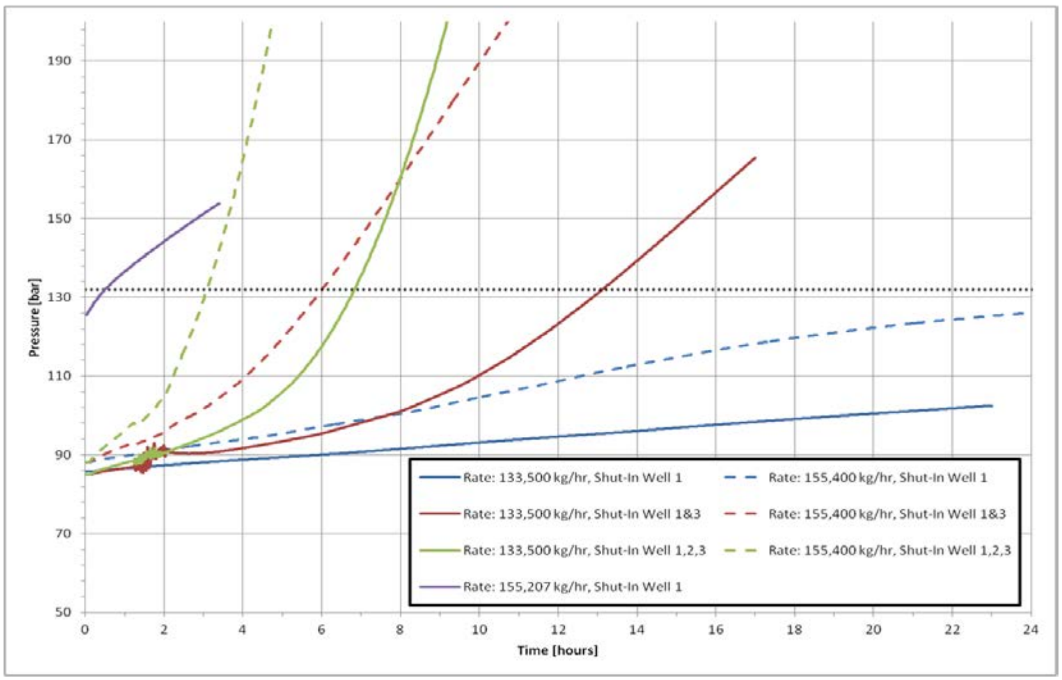

Figure 6.9 Increase of inlet pressure due to well shut-in

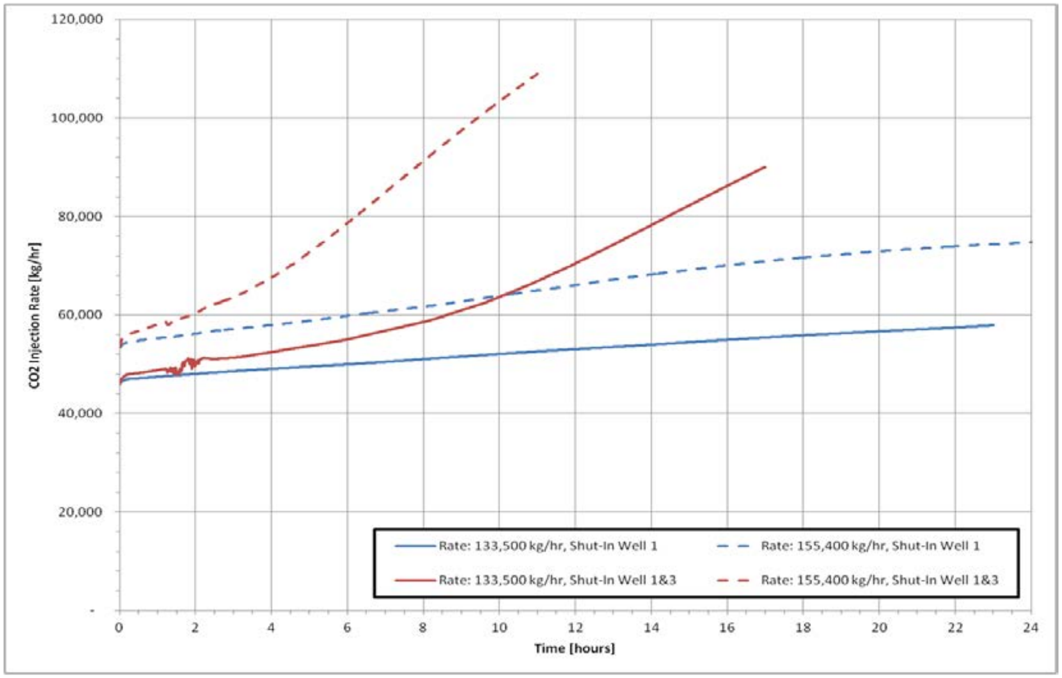

Figure 6.10 Change in well 2 injection rate after shut-in of wells 1 and 3

6.4. Pressure Decrease in Pipeline due to a Compressor Shut-in

There were two cases looked at following a shutdown of the compressor. In the first cases, the wells remain open. This case is meant to determine the amount of time available to shut-in the wells prior to reaching the two-phase region before the wells also need to be shut-in.

Figure 6.11 shows the pressure decrease in the system during a normal shut-in. In this case, steady state operation is achieved, then at 60 minutes, the compressor is shutdown and the wells remain open. Almost immediately, the pressure starts to decrease and continues to decrease until the two-phase gas-liquid region is reached. The reaction time here depends on the initial pressure in the pipeline. At low pressure operation, the reaction time is about 1 hour, while at high pressure the reaction time is closer to 3 hours. Figure 6.11 shows the pressure at the inlet to the pipeline and shows the first couple of hours of the shut-in. At longer times, if the wells remain open, the inlet pressure will equilibrate with the wellhead pressures as shown in Figure 6.35.

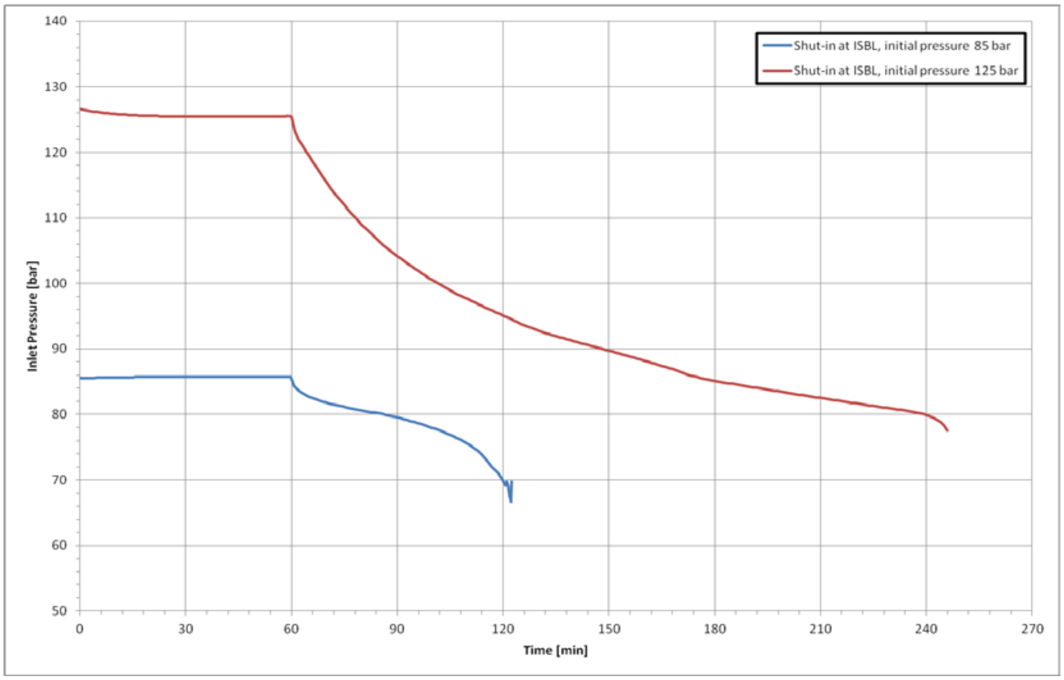

Figure 6.11 Pressure decrease due to compressor shut-in

Another case where there is the potential to get decrease in the temperature is during a normal shut-in. Due to the large density variation of the CO_2 with temperature, the cooling of the fluids in the pipeline. As the CO_2 cools, the density increases, meaning that a given mass of fluid in the pipeline occupies less volume, so for a fixed volume, the pressure in the pipeline must decrease. The extent of cooling will be greatest when the variation in temperature is highest, i.e. winter operations.

Figure 6.12 shows a typical cooldown at the various pipeline sections following a normal shut-in when both the compressor and wells are closed at the same time. At locations closest to the inlet, the temperatures slowly decrease towards ambient conditions, which in this particular case are for summer operation. At locations further away from the compressor, the temperatures are similar the soil temperatures so they experience very little additional cooling. Note that the time scale for cooling of the pipeline is very long, hence the pressure change in this case is also expected to be much slower. Figure 6.13 shows the corresponding change in pressure due to the temperature decrease shown in Figure 6.12.

Figure 6.14 shows the response of the inlet pressure for a number of different conditions. Depending on the time of year (ambient temperature), the amount of time before the system decreases to the two-phase gas-liquid region varies from about 12 hours (low pressure operation in winter) to greater than 10 days (high pressure operation in the summer).

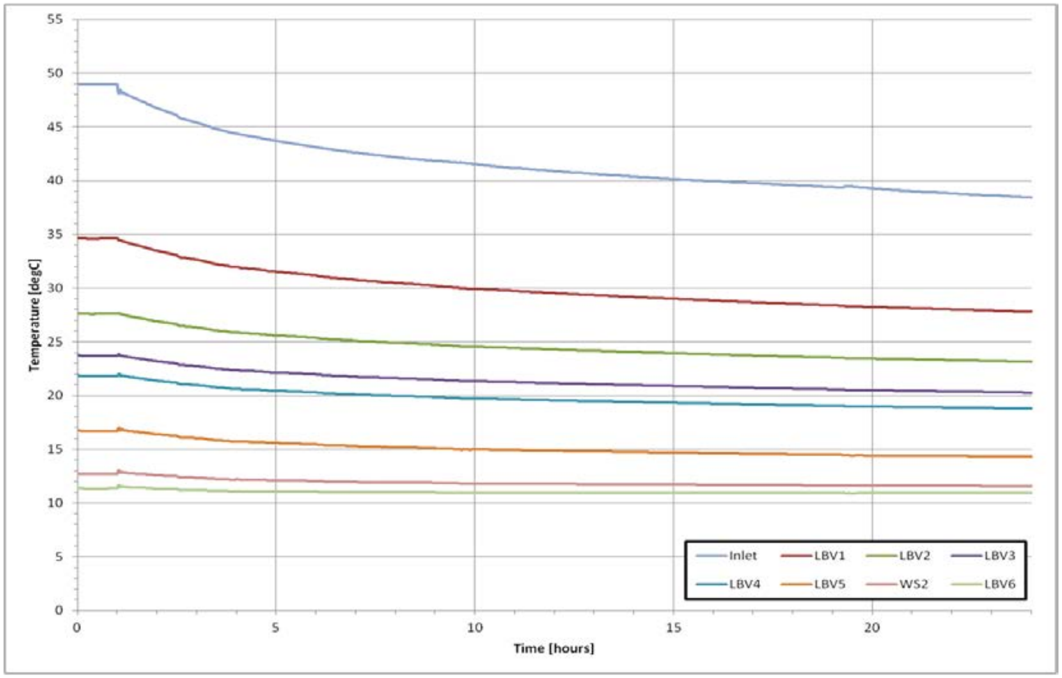

Figure 6.12 Cooldown times following system shut-in

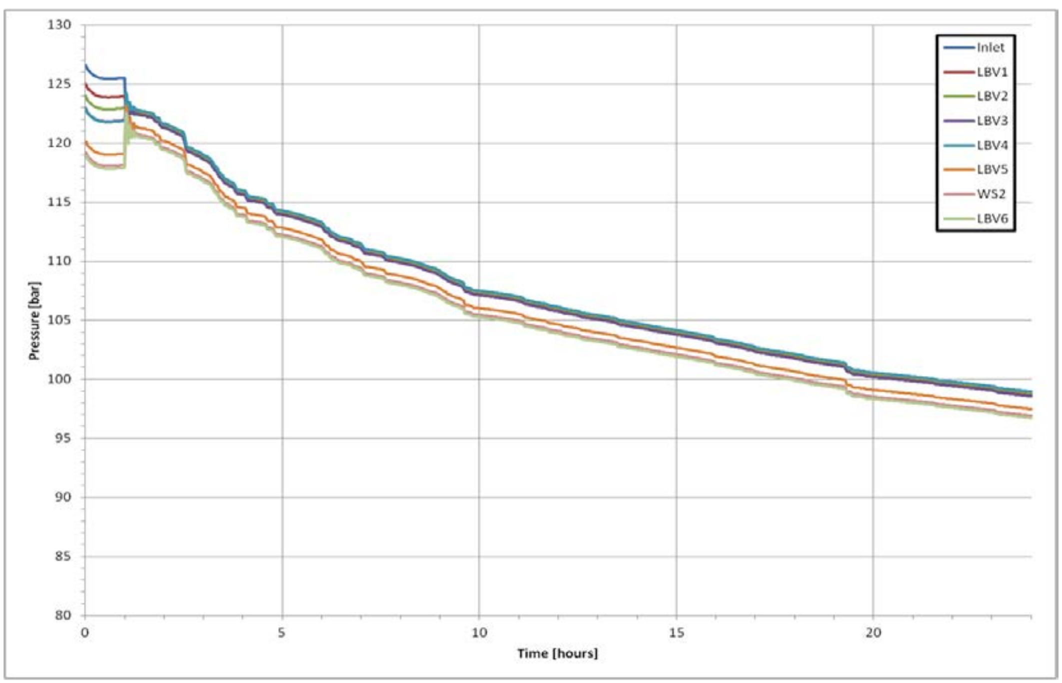

Figure 6.13 Pressure change in system upon shut-in (summer case)

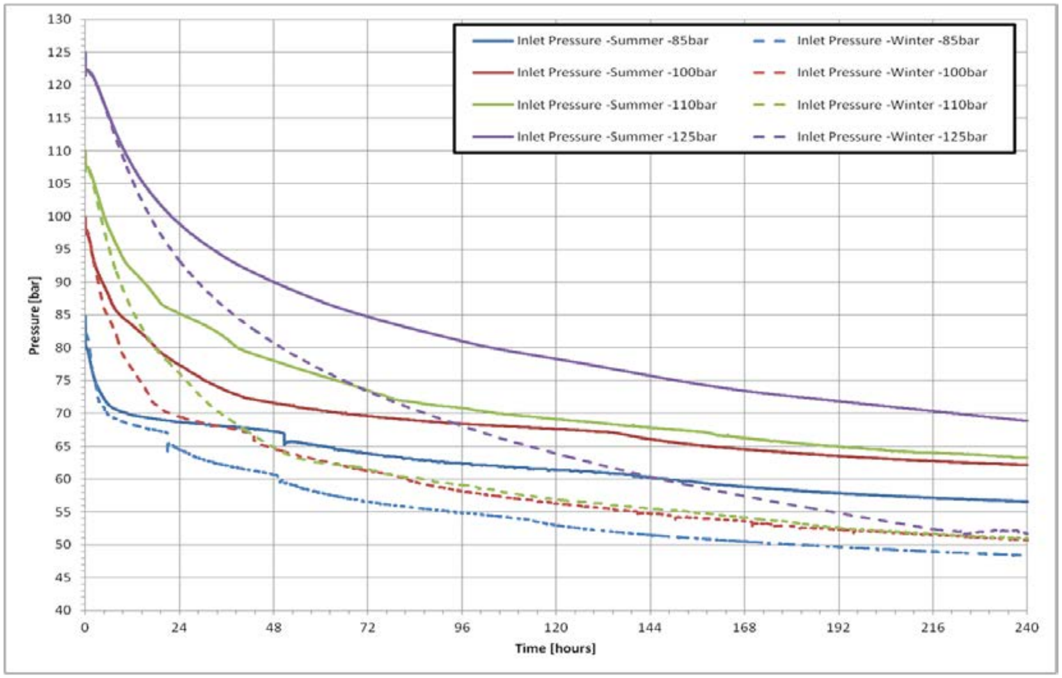

Figure 6.14 Inlet pressure decrease due to system shut-in

6.5. Blowdown Assessment

The blowdown of the pipeline is not an expected operation, but may occur periodically for inspection and maintenance operations. In the previous work, a number of different cases were tested to determine a recommended size for the blowdown valve. The main issue during blowdown is cold temperatures less than the material rating of the pipeline and solid CO_2 formation resulting in blockage and trapped pressure. If the cold temperatures can be prevented, it also protects against the formation of solid CO_2.

The previous work assumed that the vent rate of CO_2 was unconstrained. Subsequent to that work, CO_2 dispersion modeled was done, which assumed a release rate of about 80,000 kg/hr. Based on the results of the dispersion modeling, the rate inside the Scotford battery limit (ISBL) is limited to 80,000 kg/hr, but at the LBV locations, there is no similar constraint. Figure 6.15 details the rates assumed in the initial modeling for the blowdown of each section between the line block valve. Initial rates are highest, but then as the pipeline pressure decreases, the rates drop off quickly and remain relatively low for the duration. Once the CO_2 becomes two-phase in the pipeline, the venting rate is largely determined by the rate of vaporization of CO_2, which is controlled by the rate of heat transfer to the system.

In the previous work, the problematic cases involved low spots at locations at the opposite end of the vent. The detailed topography was available for this work, see Figure 4.6, and was used to model the blowdown of each of these sections. In each case, the section was blown down from only one end of the pipeline. For each section a separate case was run by blowing down at either end. The results of this case is shown in Figure 6.16 through Figure 6.21. The blowdown of three of the sections results in pipe wall temperatures of less than -40°C. These blowdown curves assume winter conditions. The temperatures can be expected to be higher during summer operations, so that some of the marginal cases in winter are feasible during summer.

Figure 6.18 shows the results for the blowdown of the section between LBV2 and LBV3. These temperatures result in values close to -40°C, and will require a different blowdown strategy than single-sided blowdown. Figure 6.20 show similar results for the section between LBV4 and LBV5. In this case the blowdown temperatures are slightly better, so the strategy develop for the LBV2-3 section will be sufficient for the LBV4-5 section. Figure 6.19 shows similar behavior, but with much lower anticipated temperatures and it is expected that this section will require a different approach to blowing down the pipeline.

Figure 6.22 shows the results of blowing down the well laterals. In all cases here, the temperatures are significantly below -40°C and will need to be operated differently.

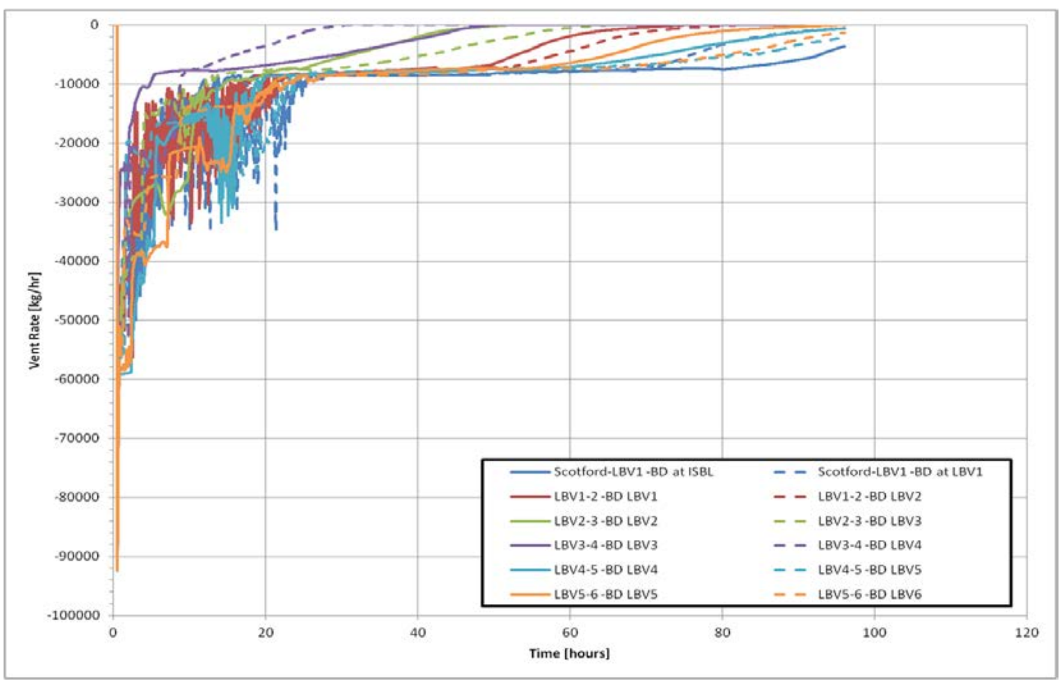

Figure 6.15 Blowdown rate (controlled rate cases)

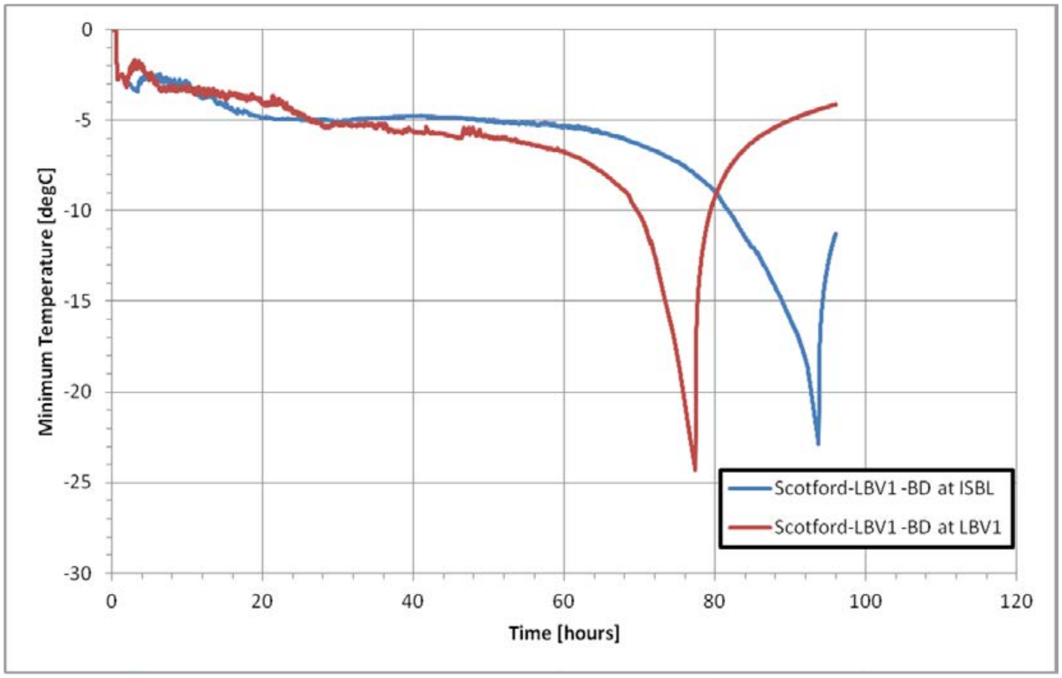

Figure 6.16 Blowdown of section between Scotford and LBV1

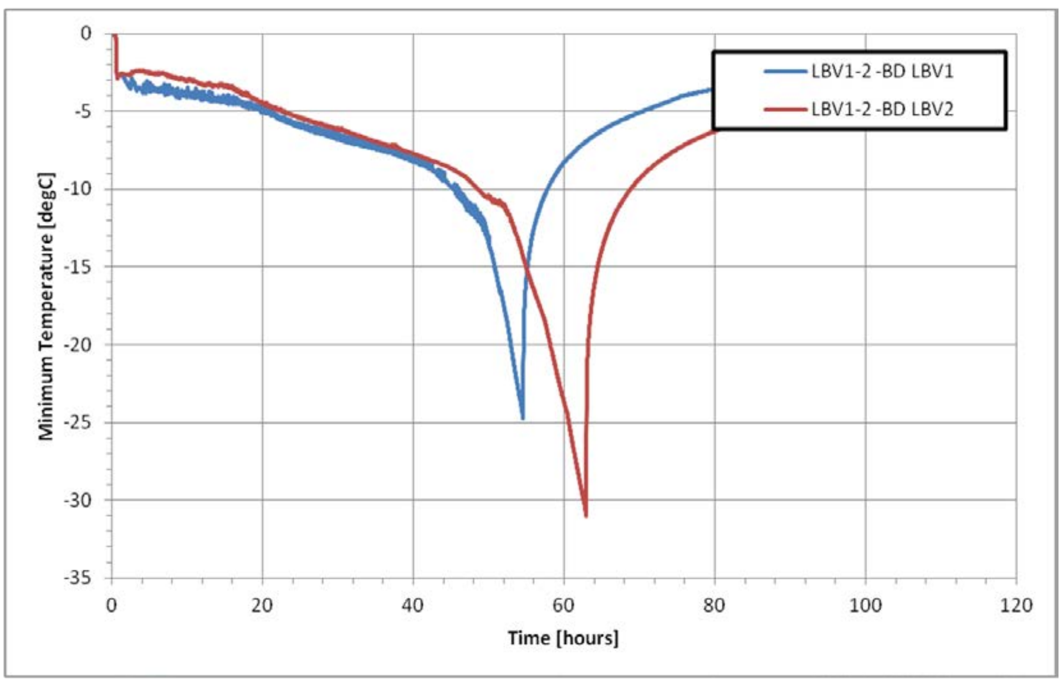

Figure 6.17 Blowdown of section between LBV1 and LBV2

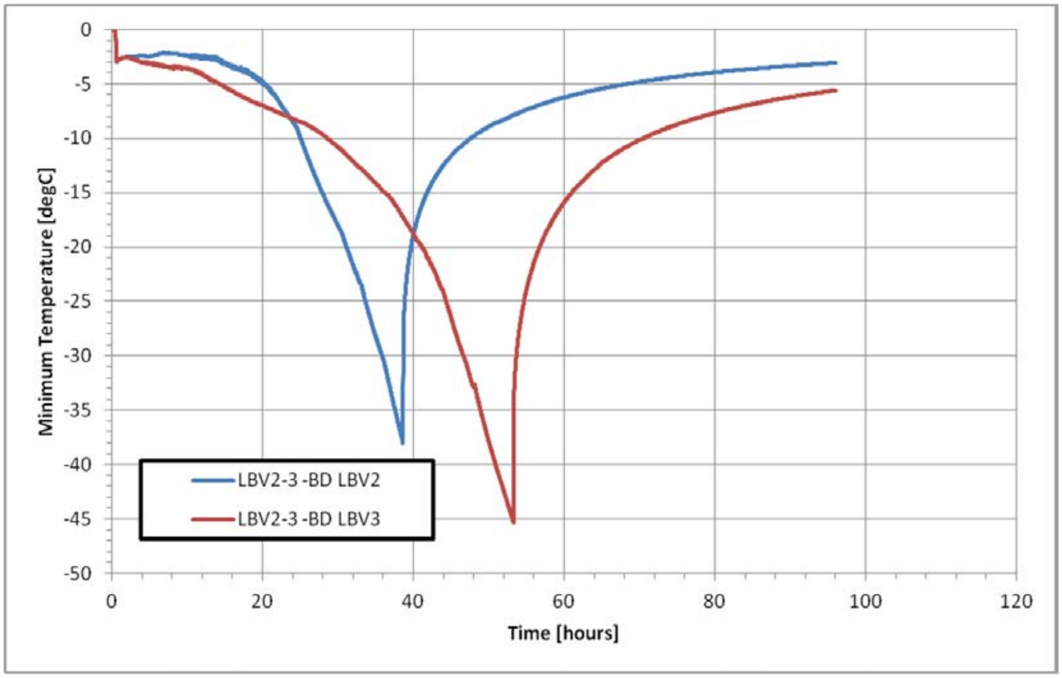

Figure 6.18 Blowdown of section between LBV2 and LBV3

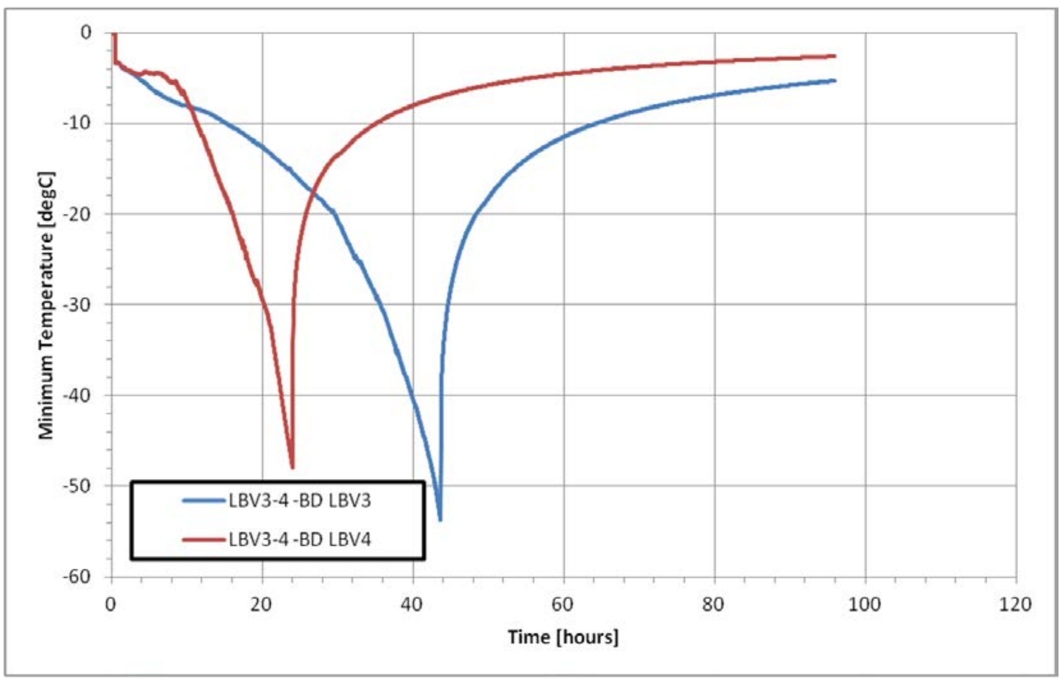

Figure 6.19 Blowdown of section between LBV3 and LBV4

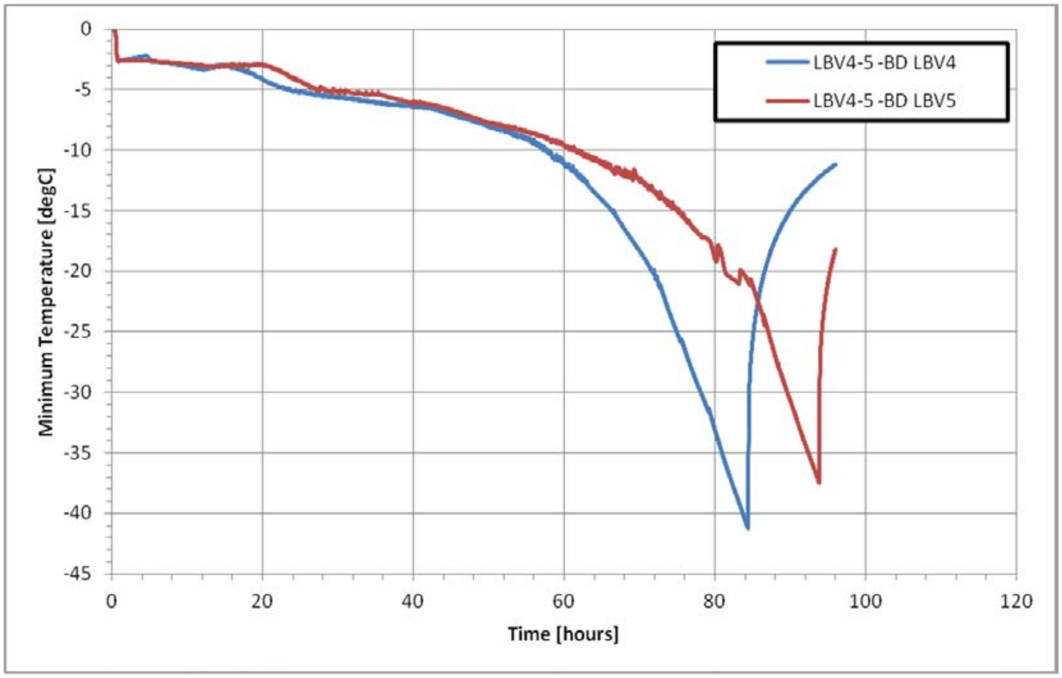

Figure 6.20 Blowdown of section between LBV4 and LBV5

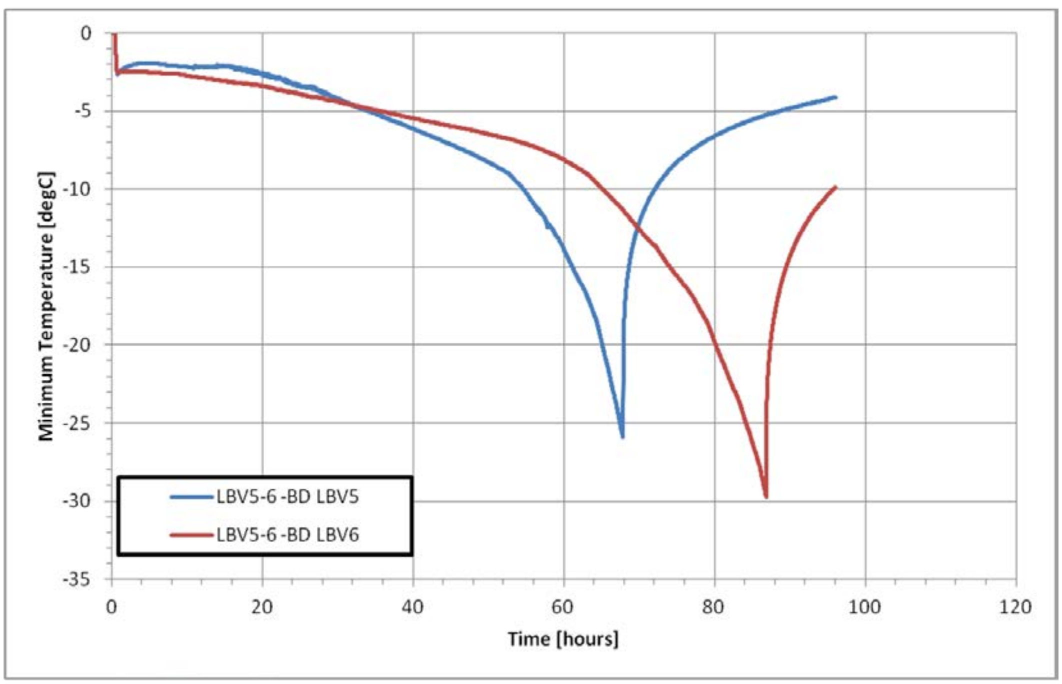

Figure 6.21 Blowdown of section between LBV5 and LBV6

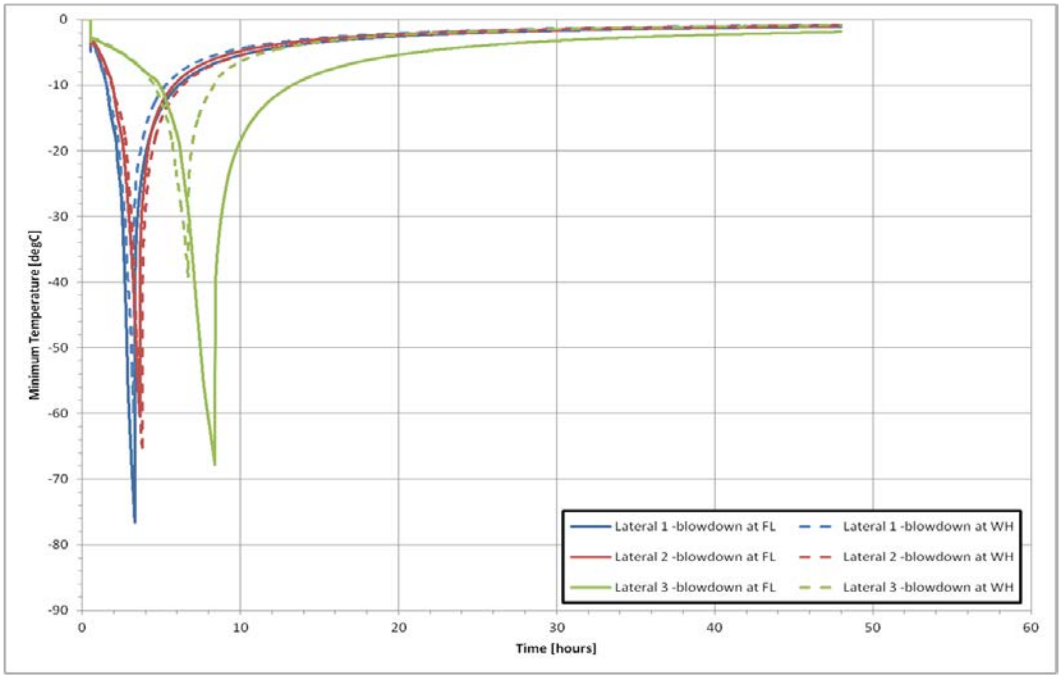

Figure 6.22 Blowdown of well lateral sections

6.5.1. Blowdown of LBV2 to LBV3

Given that a single-sided blowdown of the section LBV2-3 results in temperatures less than -40°C, several alternate operations were looked at, namely dual-sided blowdown at fast (Figure 6.23) and at controlled rates (Figure 6.25). When the venting rate is not constrained, higher pipe wall temperatures result. The fluid temperatures tend to be lower, but the duration is less, so the pipe wall temperatures have less time to equilibrate with the fluid temperatures. Figure 6.24 shows that in the case of a fast dual-sided blowdown, the pipe wall temperatures remain above -40°C. But in the case where the rate is constrained, Figure 6.26, temperature less than -40°C are still possible.

Figure 6.27 is included to show the pressures corresponding to a given temperatures. In all cases, the temperatures and pressures roughly follow the phase equilibrium line. Therefore, the low temperatures always occur at relatively low pressures. Although in this work, that is not taken into consideration and temperatures of less than -40°C are avoided at all pressures.

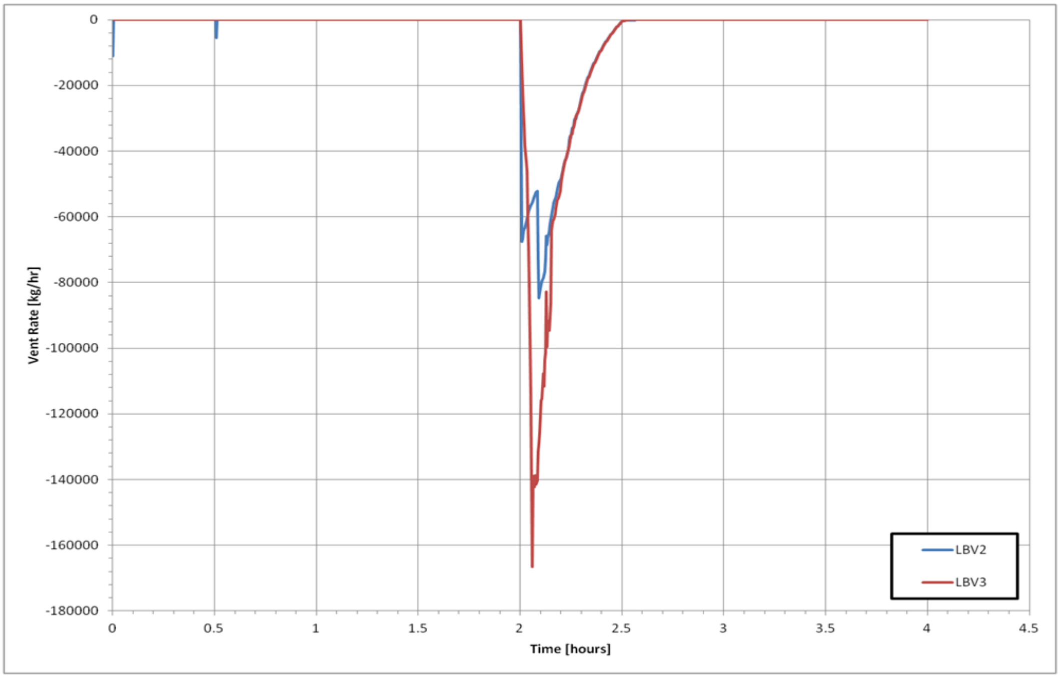

Figure 6.23 Fast dual sided blowdown of section between LBV2 and LBV3

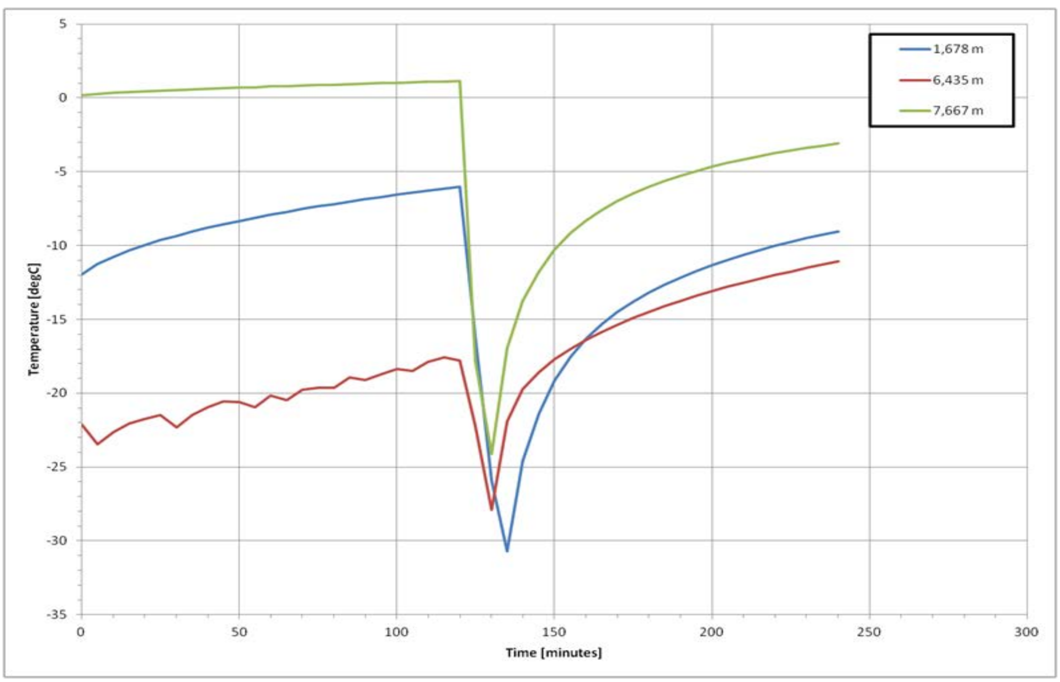

Figure 6.24 Temperatures during fast dual-sided blowdown at coldest locations (LBV2 to LBV3)

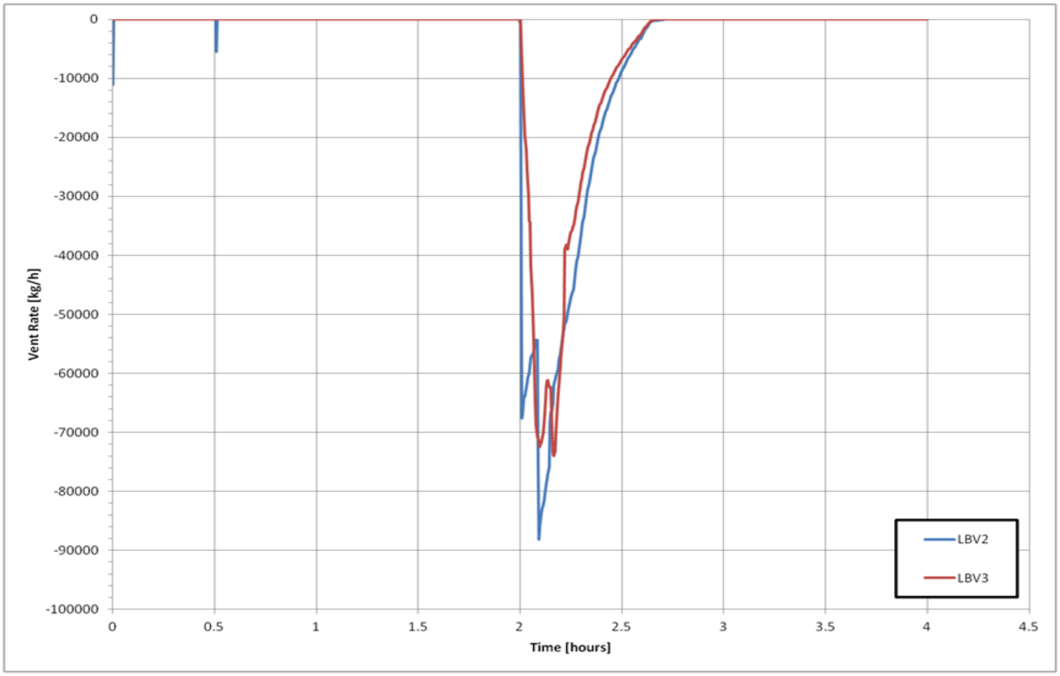

Figure 6.25 Controlled dual sided blowdown of section between LBV2 and LBV3

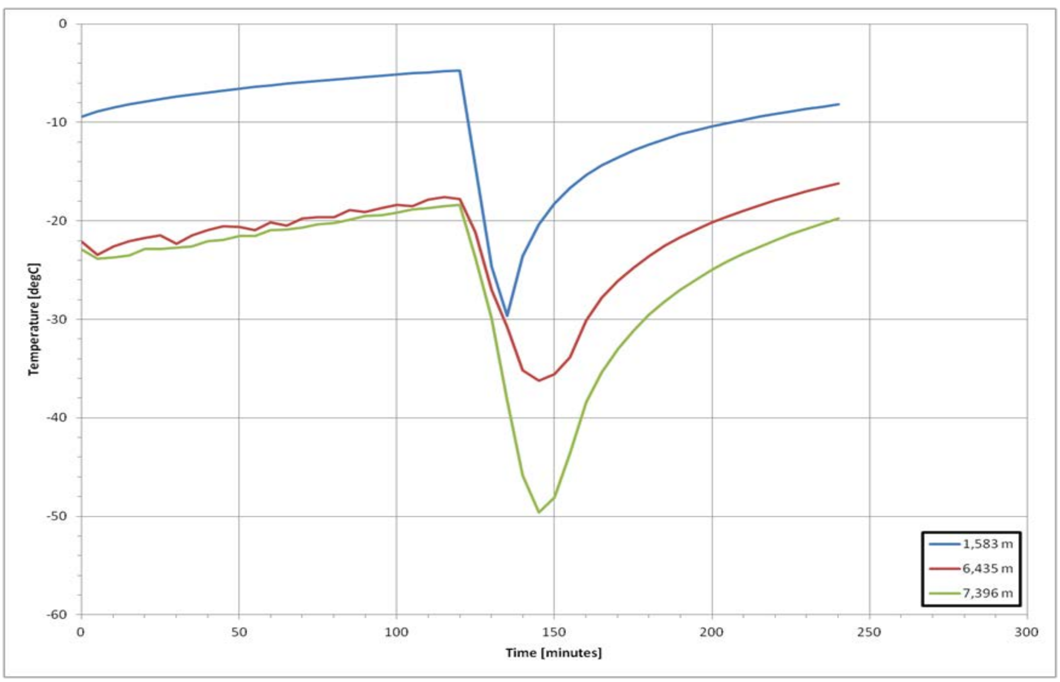

Figure 6.26 Temperatures during controlled dual-sided blowdown at coldest locations (LBV2 to LBV3)

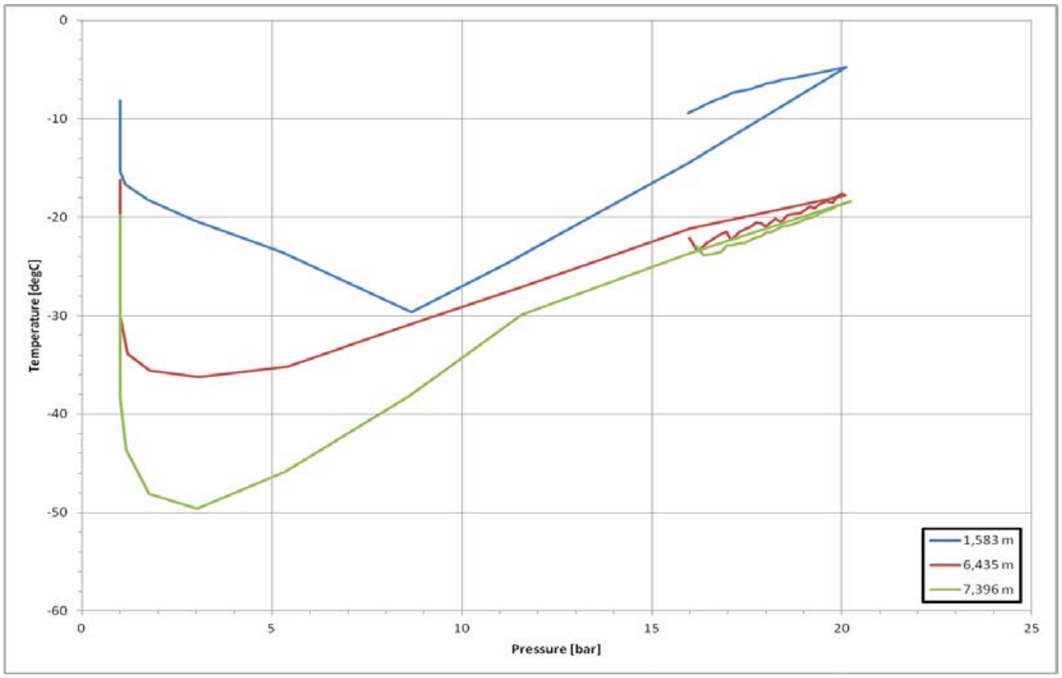

Figure 6.27 Temperature/Pressure profile during controlled dual-sided blowdown of section between LBV2 and LBV3

6.5.2. Blowdown of LBV3 to LBV4

The pipeline section between LBV3 and LBV4 has a river crossing, which results in a significant low spot relative to all the other sections looked. This low spot creates some issues with low temperatures. In the other sections, the collection of liquid ultimately results in the cold temperatures. The presence of this low spot collects enough liquid that it becomes difficult to remove it prior to the system pressure decreasing.

Figure 6.28 shows the venting rate for a fast blowdown case and Figure 6.29 shows the resulting pipe wall temperatures. Unlike the lBV2-3 section, a fast dual-sided blowdown approach does not work.

The next approach modeled was a controlled blowdown, but in a staged manner. In this case the system was vented until cold temperatures are observed, then the system is shut-in and allowed to warm back up. The blowdown occurs in stages like this until the flowline pressure is fully reduced. Figure 6.30 shows the results of this staged type approach. The key is to be able to remove as much liquids as possible prior to decreasing the pressure much below about 5 bar.

Figure 6.31 shows the fluid and pipe wall temperatures during this staged approach. This was more of a proof of concept that this approach would work. In the model results, the pipe wall temperatures are still close to the -40°C criteria. Additional work needs to be done to better define the actual operating procedure, since in field there is not the benefit of having a temperature measurement at the river crossing. Figure 6.32 shows the temperature trends at the three coldest locations in this section. Note the river crossing is by far the most difficult section to control to achieve the temperatures >-40°C.

The recommended procedure is to base the times on pressure, since that is relatively constant along the length of the flowline. In this particular case, the blowdown sequence was as follows:

1. Blowdown system from initial pressure to about 20 bar and hold for at least 1 hour
2. Blowdown to 12 bar and hold for at least 2 hours
3. Blowdown to 12 bar again and hold for at least 3 hours
4. Blowdown to 8 bar and hold for at least 3 hours
5. Blowdown to 5 bar and hold for at least 3 hours
6. Blowdown to 3 bar and hold for at least 3 hours
7. Blowdown system to atmospheric pressure

Details of this procedure including pressure and duration recommendations may change once the thermal properties of the system have been benchmarked.

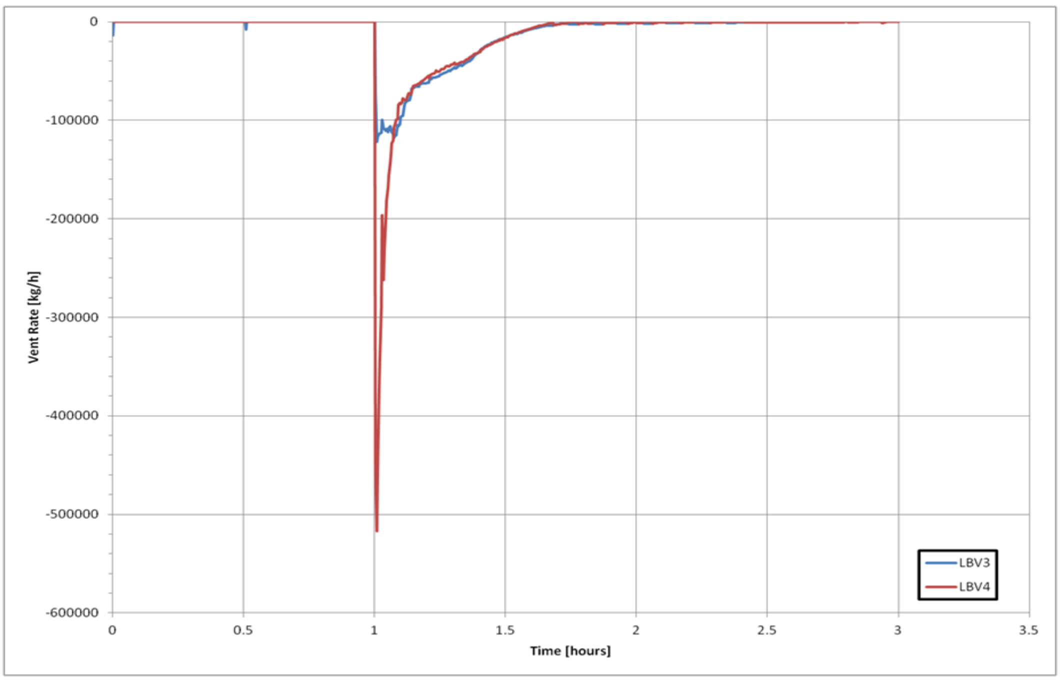

Figure 6.28 Fast dual sided blowdown of section between LBV3 and LBV4

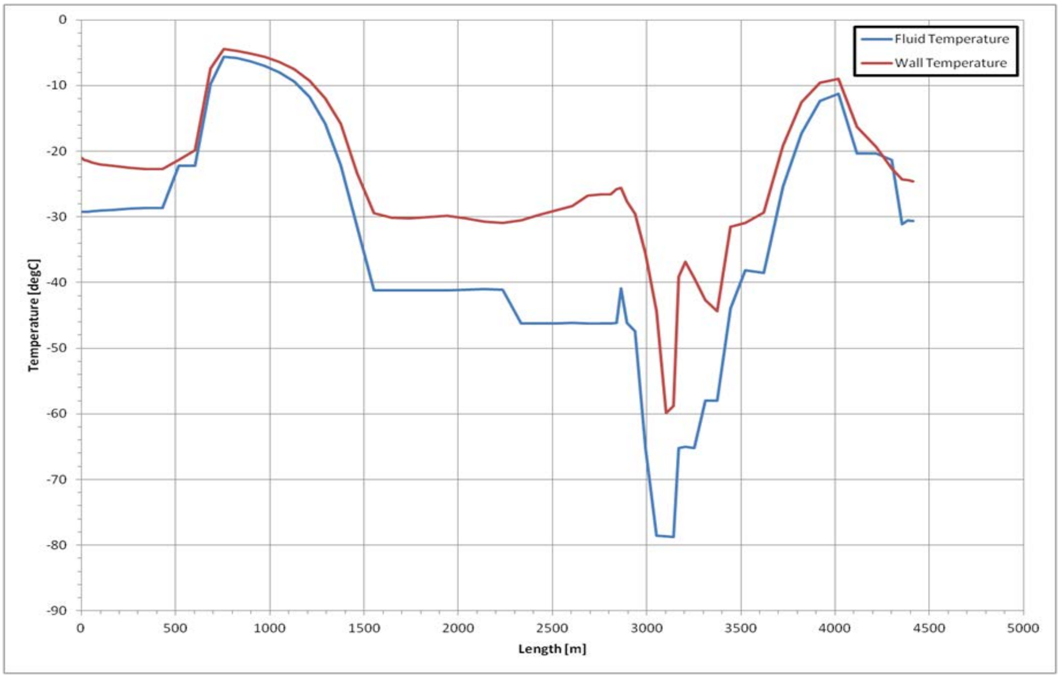

Figure 6.29 Fluid and Wall temperatures during fast dual-sided blowdown (LBV3 to LBV4)

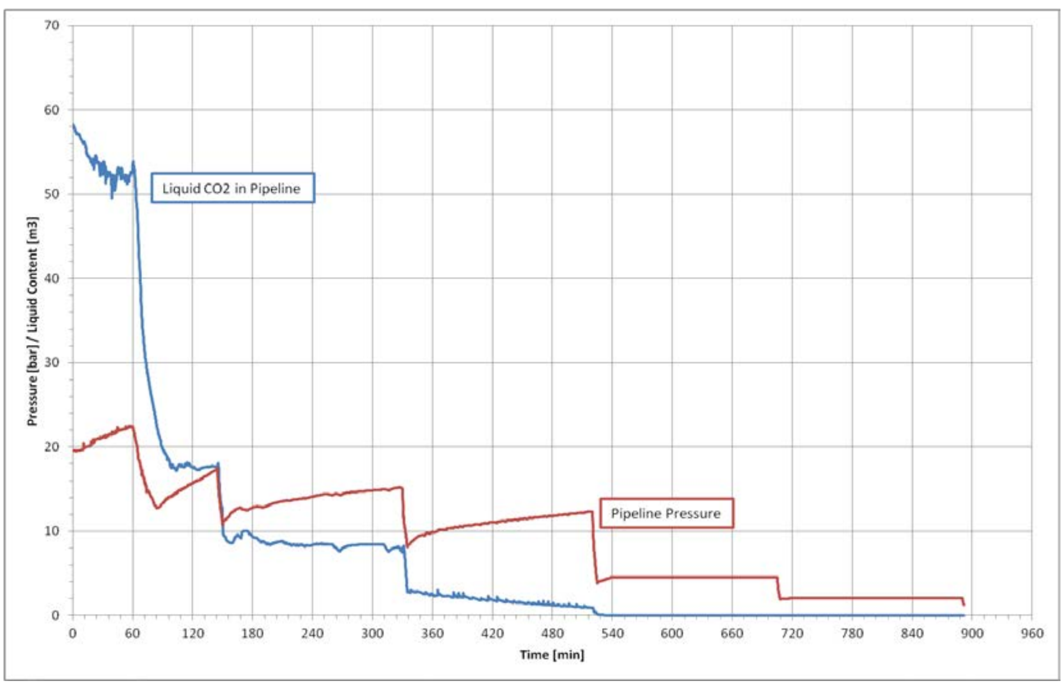

Figure 6.30 Pressure and liquid content during a controlled and staged blowdown

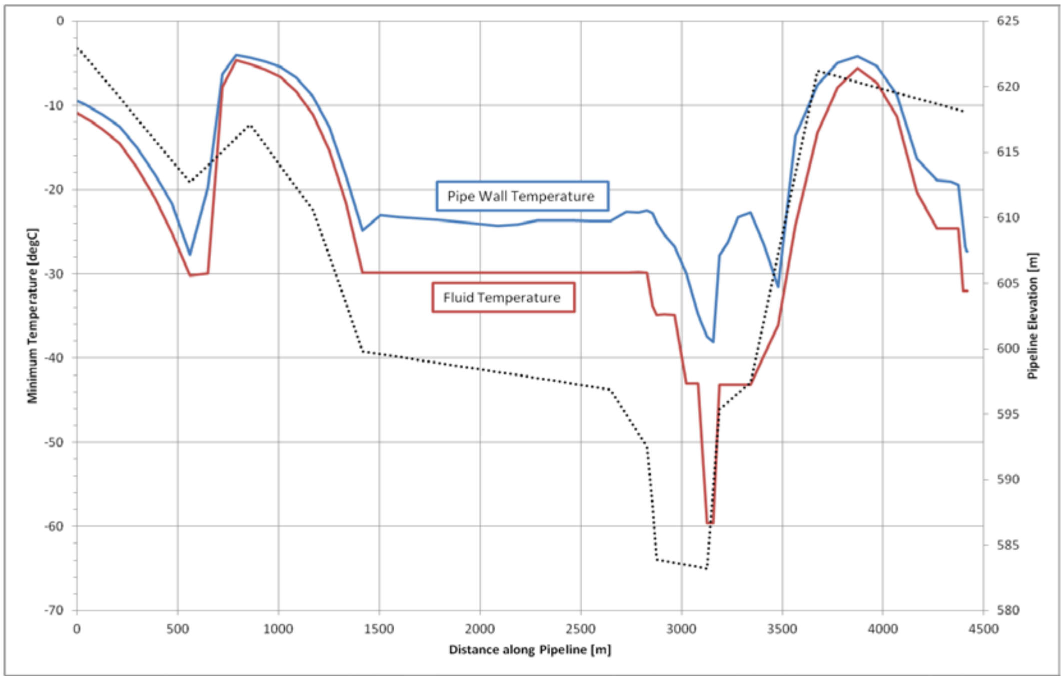

Figure 6.31 Minimum temperature in along length of pipeline

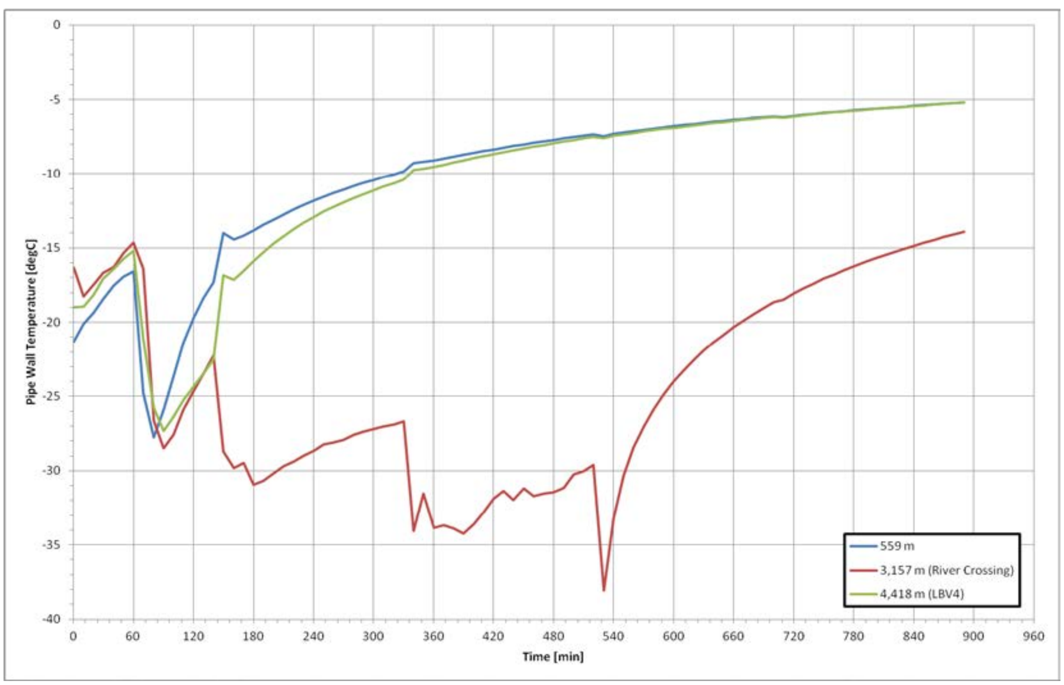

Figure 6.32 Pipe wall temperatures at low spots in pipeline

6.5.3. Blowdown of Laterals

The blowdown of the lateral sections, showed similar low temperature issues, thus a more detailed model was looked at to determine the actual pipe wall temperatures during a blowdown. The smaller pipe size in the lateral sections decreases the blowdown time. For a given blowdown rate, fluid velocities in the pipe are higher, which means that there is less fluid that accumulates in the low spots that leads to the cold temperatures during blowdown.

As was the case for the section between lBV3 and lBV4, a staged blowdown approach was used for the lateral sections and shown to be effective. Due to the relatively higher velocities in the lateral sections, fewer blowdown cycles were required. Figure 6.33 shows the pressure response during the blowdown process. Unlike the previous case, the lateral is blowndown to a pressure of about 15 bar after which the system is shut-in for about 7 hours before the final blowdown of the lateral section is completed.

Figure 6.34 shows the resulting fluid and pipe wall temperatures during this step-wise blowdown. After the initial pressure reduction, the minimum temperature occurs at the pipeline end of the lateral (near the blowdown valve). During the final blowdown step, the coldest temperatures are seen at a low spot at the far end of the pipeline, near the wellhead. The blowdown times of the laterals are relatively fast, so the pipe wall and fluid are not able to reach thermal equilibrium and the pipe wall stays sufficiently warmer than the fluid and remains above the minimum temperature rating of the pipeline.

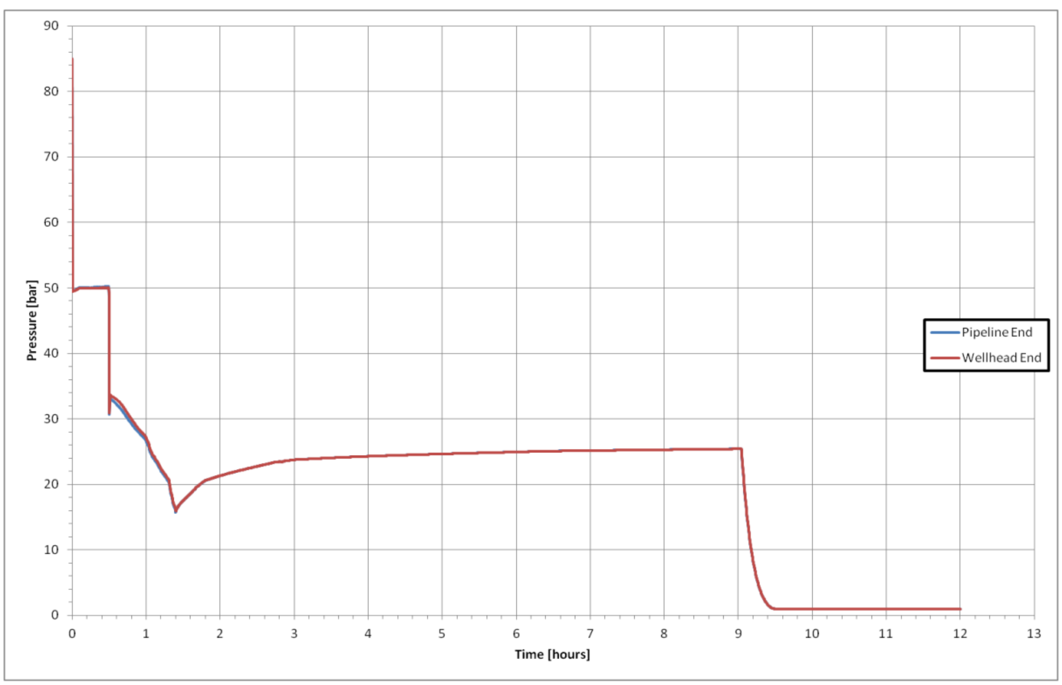

Figure 6.33 Pressure in lateral section during step-wise blowdown of lateral section

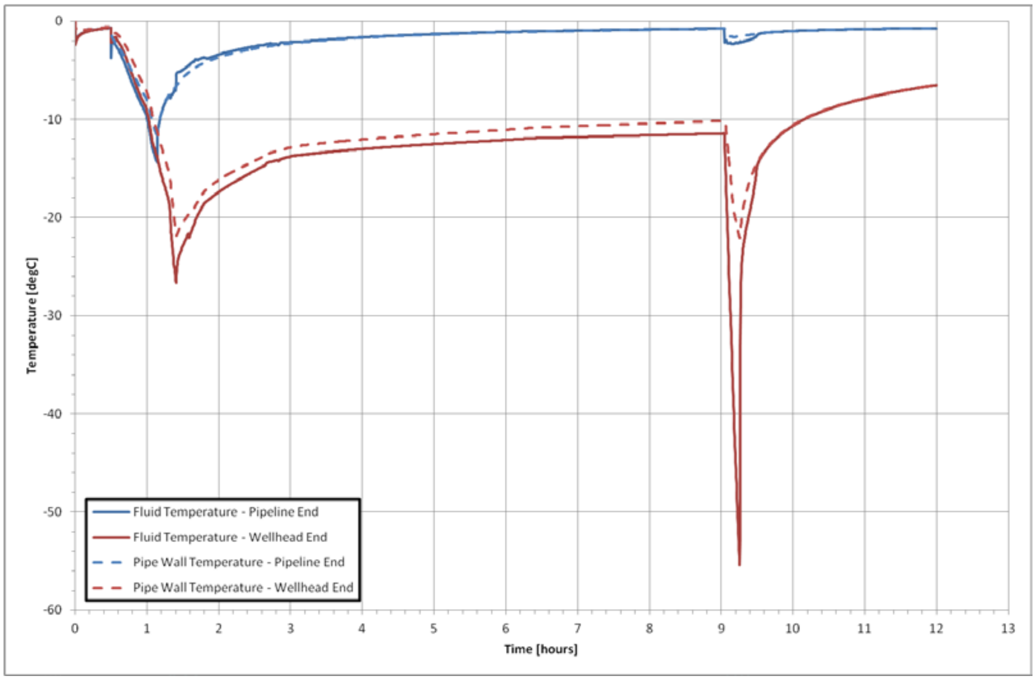

Figure 6.34 Fluid and pipe wall temperatures during step-wise blowdown in lateral section

6.6. Lateral Settle-Out Pressure

The settle out pressure in the laterals was determined. In this case it was assumed that the compressor was shut down while the wellhead chokes remained open. In this scenario the pressure in the well laterals will decrease until an equilibrium is established with the reservoir. Figure 6.35 shows the pressure response at each of the wellhead locations.

In this particular case, the system is operated at relatively low pressure. Upon shut-in of the compressor, the wellhead pressure drops quickly to a pressure of just under 50 bar. This settle out pressure is dependent primarily on the reservoir pressure and well depths. This settle out pressure will be true for all cases regardless of starting pressure or ambient conditions. These factors will impact the time it takes for the entire system to settle out at this pressure, but the final pressure will be the same.

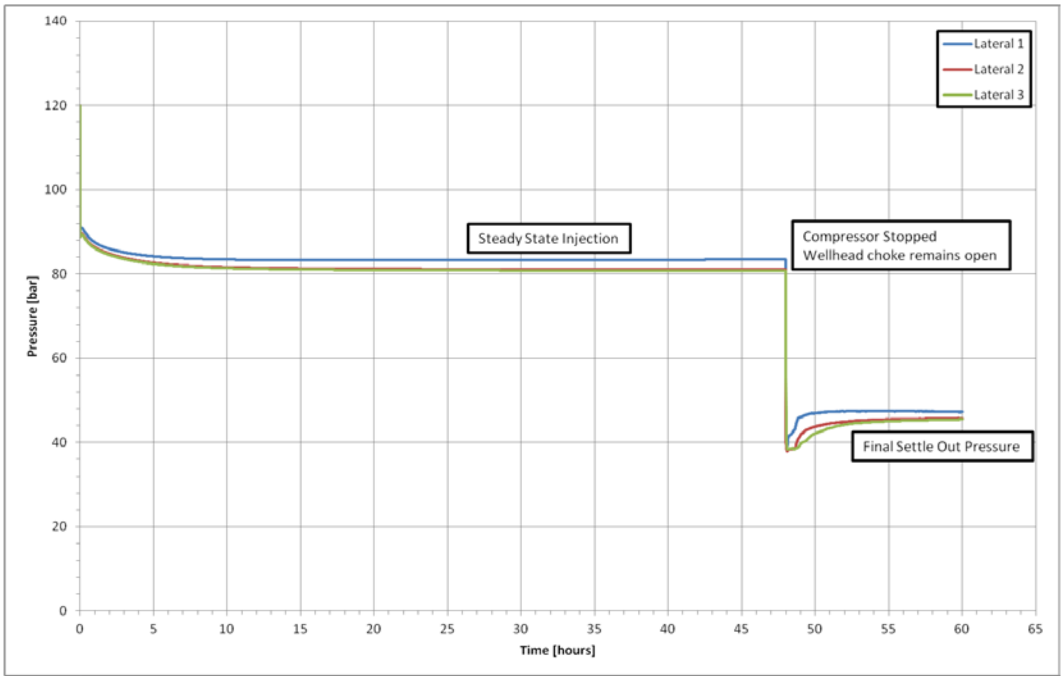

Figure 6.35 Lateral settle-out pressure following shut-in with wellhead open to reservoir

6.7. Leak Assessment

This work also included a study to determine the pressure response of the system upon development of a leak. Figure 6.36 again shows the pipeline topography along with the location of the assumed leak locations 1-4. Leak location 5 and 6 are near the well 2 lateral take-off. Leak 5 is at a low spot about 2 km away and leak 6 is very near the well 2 lateral take-off. Similarly, leak locations 7 and 8 are near the end of the pipeline, with leak 7 being in a low spot several km away and leak 8 being very near the end of the pipeline.

In these results, the rate of pressure change is plotted. The rate of pressure change is a measure of how the pressure is changing with time. So during steady state production, the rate of change is zero. Any transient events, such as a shut-in or startup will see some pressure change with time. In this case the rate of pressure change was determined for leaks at various locations to understand the magnitude of their change and if a leak could be differentiated from a typical operation. The pressure measurement of the wellhead (WH) positions is downstream of the choke, hence it sees a larger variation than the other cases, particularly when the wellhead choke is opened or closed.

Figure 6.37 shows a typical response in the change in pressure after the development of a 5 mm leak. At the initiation of the leak (1 hr) there is a sudden decrease in the pressure hence the negative rate of change. After about 10 hours the system has reached a new equilibrium and the system pressure is no longer changing. As the leak size increases, the rate of change also increases and the time it takes to re-establish a new equilibrium is increased.

Table 6.2 provides a summary of the different leak locations studied. The highlighted values represent the location that the highest rate of pressure change occurs. In the range of 5-10 mm, the largest rate of change in pressure is less than 1 kPa/s. The largest occurs near the leak location and quickly decreases in magnitude a location further away from the leak source.

As a means of comparison with the leak rate during steady state operation, the rate of pressure change was determined for several of typical scenarios expected during the operation of this system. In the first case represents both the compressor and the wells are shut-in at the same time for 12 hours, then the system is restarted with the compressor and wells opening at the same time. Case 2 is similar except that the compressor is shut-in 30 minutes after the wells are closed, thus allowing some line packing to occur in the pipeline. The third case is where only a single well is shut-in and the compressor and the remaining wells stay open. Other cases were considered, but in general, the compressor and wells are far enough apart that a change in one end does not immediately impact the other. In the cases above the maximum rate of change in pressure occurs at start of the event and is minimally impacted by events further away in the pipeline.

Table 6.3 provides a summary of the results for these typical cases. For these typical operations, the rate of change in pressure at the different locations is larger than those observed for the 5-10 mm leaks. Based on this, a simple rate of pressure change monitoring is not sufficient to observe whether or not a leak has occurred in the system. Instead, some combination of pressure monitoring along with a tracking of the compressor discharge rate and well injection rates is needed.

Figure 6.38 and Figure 6.39 show the impact of the leak size on the rate of pressure change. As the size of the leak increases, the rate of pressure change in the system increases. As with the previous cases, the largest rate of change occurs at the LBV closest to the leak. For a leak close to an LBV, the leak size would have to be greater than about 55 mm (2.2 inches) to register a rate of pressure change at the LBV of greater than 20 kPa/s.

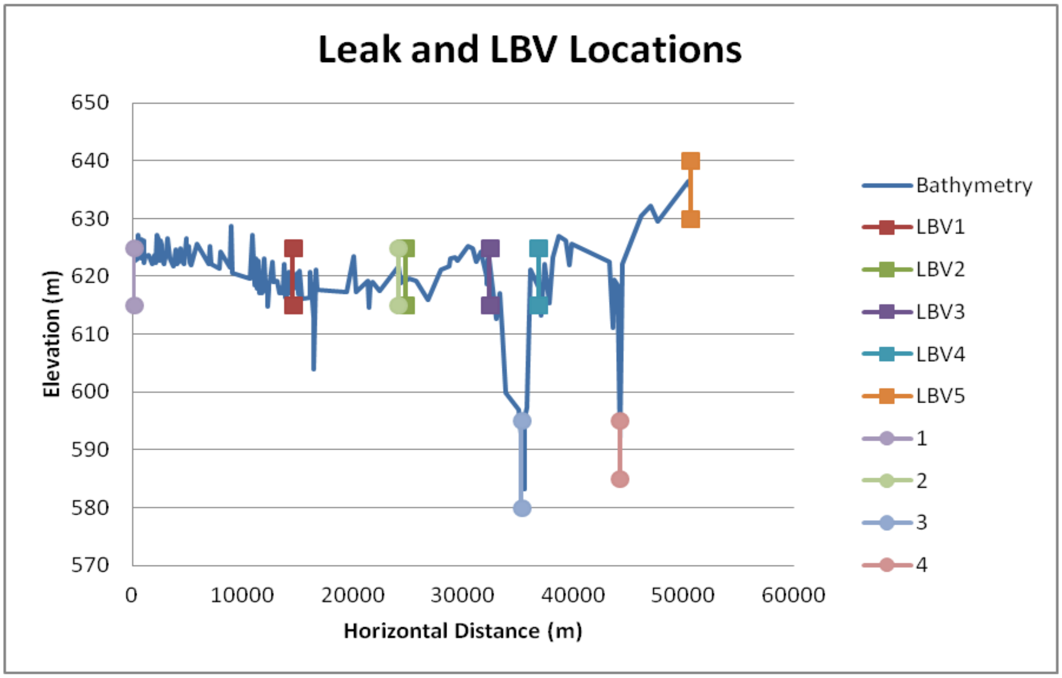

Figure 6.36 Assumptions for leak locations (Scotford to LBV5)

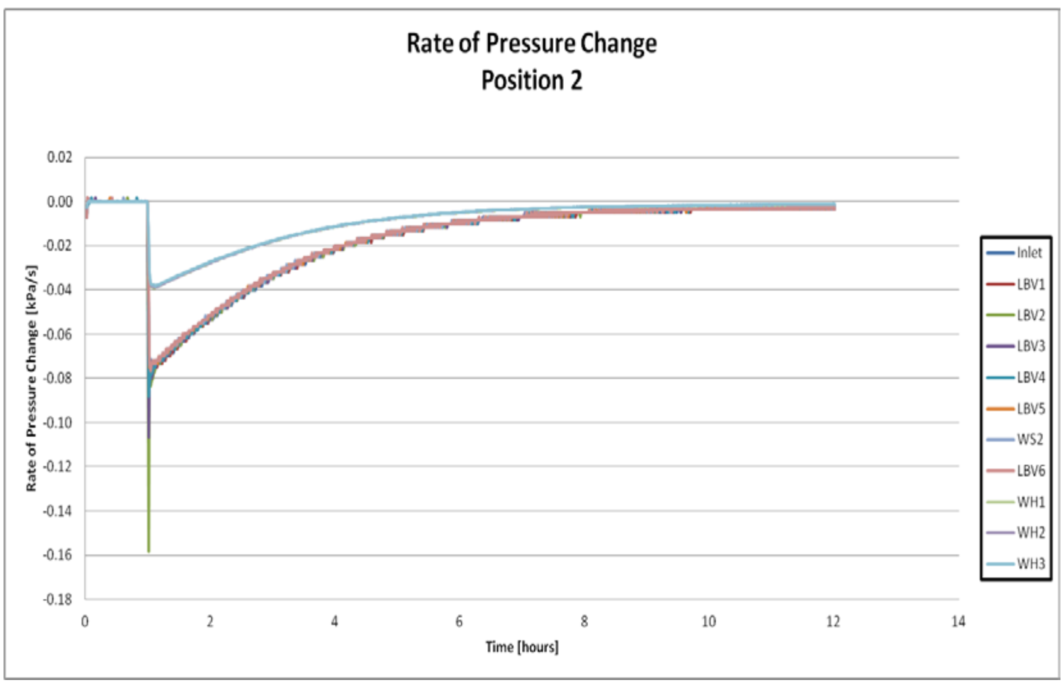

Figure 6.37 Typical rate of pressure change after formation of a 5mm leak

Table 6.2 Summary of leak results during steady state operation

	Leak 1		Leak 2		Leak3		Leak 4		Leak 5	Leak 6	Leak 7	Leak 8
	5 mm leak	10 mm leak	5 mm leak	10 mm leak	5 mm leak	10 mm leak	5 mm leak	10 mm leak	5 mm leak	5 mm leak	5 mm leak	5 mm leak
	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|	Min |dP/dt|
	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s
Inlet	-0.182	-0.728	-0.075	-0.358	-0.075	-0.290	-0.073	-0.283	-0.072	-0.073	-0.073	-0.072
LBV1	-0.075	-0.302	-0.088	-0.635	-0.075	-0.295	-0.075	-0.288	-0.073	-0.078	-0.078	-0.073
LBV2	-0.060	-0.238	-0.158	-0.432	-0.102	-0.408	-0.082	-0.325	-0.078	-0.097	-0.098	-0.078
LBV3	-0.058	-0.228	-0.107	-0.353	-0.158	-0.640	-0.108	-0.437	-0.098	-0.110	-0.112	-0.098
LBV4	-0.058	-0.227	-0.088	-0.305	-0.175	-0.702	-0.140	-0.560	-0.110	-0.195	-0.192	-0.110
LBV5	-0.057	-0.220	-0.075	-0.308	-0.105	-0.423	-0.167	-0.665	-0.205	-0.283	-0.285	-0.190
WS2	-0.057	-0.220	-0.075	-0.308	-0.107	-0.432	-0.140	-0.562	-0.245	-0.277	-0.312	-0.283
LBV6	-0.057	-0.220	-0.077	-0.155	-0.107	-0.435	-0.137	-0.547	-0.238	-0.080	-0.078	-0.335
WH1	-0.030	-0.117	-0.039	-0.154	-0.050	-0.203	-0.068	-0.270	-0.084	-0.114	-0.115	-0.078
WH2	-0.030	-0.117	-0.039	-0.152	-0.050	-0.202	-0.064	-0.258	-0.099	-0.107	-0.121	-0.114
WH3	-0.030	-0.115	-0.038	-0.292	-0.049	-0.198	-0.064	-0.255	-0.093	-0.072	-0.072	-0.130

Table 6.3 Summary of rate of pressure change results from transient cases

	Line pack 1		Line pack 2		Line pack 3	
	During 12-hour shut in	After restart	During 12-hour shut in	After restart	During 12-hour Well-02 shut in	After restart
	Min (dP/dt)	Max (dP/dt)	Min (dP/dt)	Max (dP/dt)	Min (dP/dt)	Max (dP/dt)
	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s	kPa/s
Inlet	-4.269	3.814	-11.877	2.837	0.634	-2.364
LBV1	-2.049	1.556	-5.557	2.212	0.511	-2.562
LBV2	-1.013	0.258	-4.072	0.062	0.751	-2.392
LBV3	-0.799	0.396	-3.404	0.250	0.802	-2.486
LBV4	-1.112	0.541	-3.075	0.457	0.811	-3.097
LBV5	-1.792	1.009	-1.866	1.035	1.624	-5.313
WS2	-1.977	1.082	-1.173	1.095	1.988	-6.010
LBV6	-2.006	1.127	-1.191	1.118	1.976	-6.489
WH1	-66.113	48.873	-66.113	72.401	0.782	-2.539
WH2	-65.018	34.190	-65.018	55.556	-55.742	78.103
WH3	-66.761	45.939	-66.761	69.754	0.974	-3.155

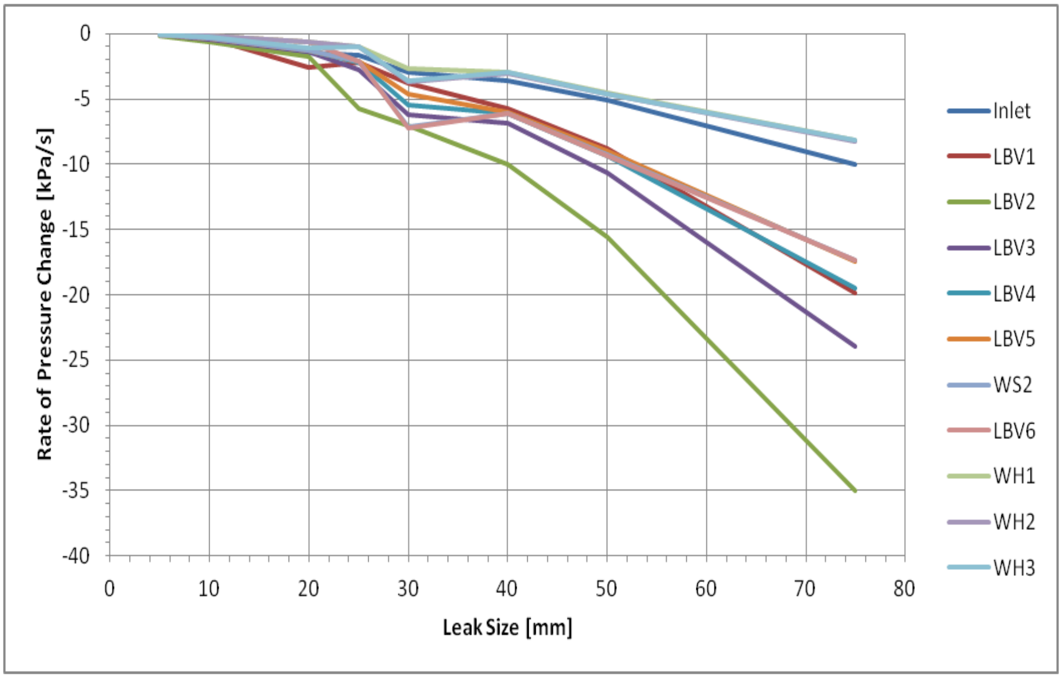

Figure 6.38 Rate of pressure change for Leak 2 (near LBV 2)

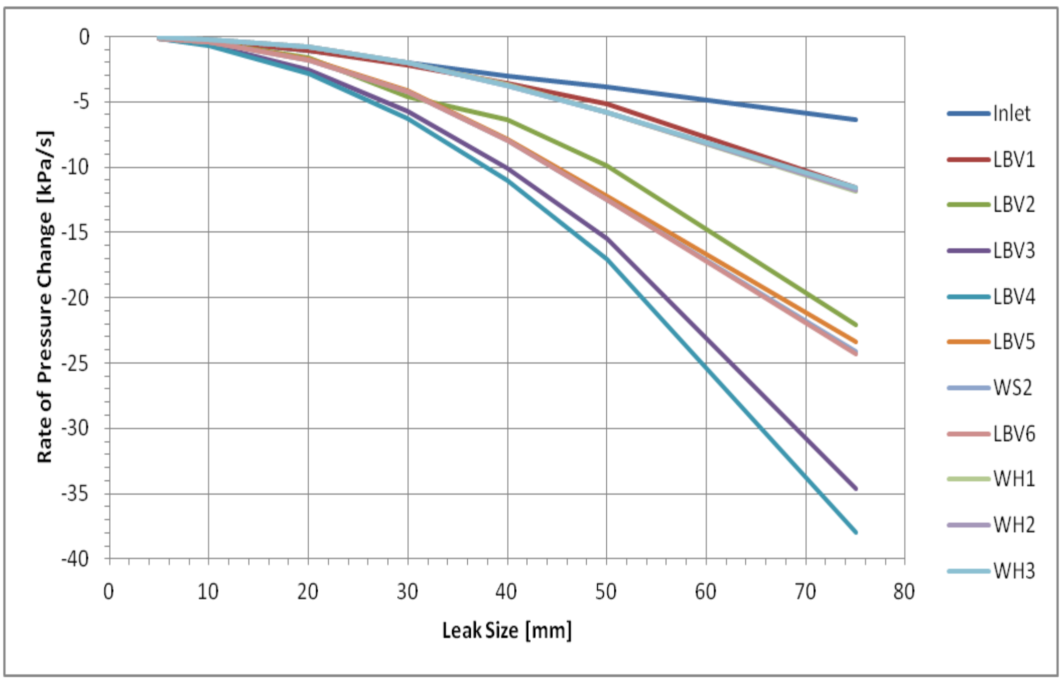

Figure 6.39 Rate of pressure change for Leak 3 (low spot between LBV3 and LBV4)

7. LIQUID SURGE ANALYSIS IN WELLBORE

Due to concern of fracturing the formation during transients as CO_2 is injected in the reservoir, wellbore pressure surge analysis was performed assuming an instantaneous of valve shut-in at wellhead. Various cases were investigated, these included the base and sensitivity cases to see thermal effects during seasonal changes.

Results showed that there was no indication of surge could potentially damage the formation during valve shut-ins at wellhead.

Relevant information used in these studies are,

<u>Assumptions:</u>

1. Formation fracturing pressure = 30 MPa
2. Reservoir pressure = 20 MPa
3. Bottom hole pressures
   a. Base case = 27.2 MPa
   b. Sensitivity cases: winter = 22.7 MPa and summer = 27 MPa
4. Wellhead temperatures
   a. Base case = 0°C
   b. Sensitivity cases: winter = -5°C and summer = 12°C
5. Valve closing time at wellhead = 1 ms (0.001 s)

<u>Wellbore geometry:</u>

Tubing: L = 2060 m; elevation = 2060 m (vertical); ID = 75.997 mm (2.992")

<u>Program tool:</u>

AFT Impulse version 4.0

<u>Modeling methodology:</u>

1. Since the bottom hole pressure is higher than the reservoir pressure, an exit valve (or choke) is placed at the bottom of tubing; the exit pressure is set at 20 MPa (reservoir pressure).
2. For each of the cases, steady state conditions are established by choking the exit valve such that the bottom hole pressure (u/s valve pressure) is accomplished. As such, the driving force is the delta pressure between the bottom hole and the reservoir.
3. Following steady state operation, surge analysis is conducted by immediate valve shut-in at wellhead.

7.1. Steady State Results

Table 7.1 presents steady state conditions; note that for base case, a range of wellhead pressures between 8 and 16 MPa were investigated. As indicated, a range of CO_2 mass flow rates between approximately 30,000 and 100,000 kg/hr could be injected in the well, depending on the operating season, as well as, the wellhead pressure (for base case).

In addition, Figure 7.1 provides a plot of mass flow rates versus the wellhead pressures for base case. Evidently, the higher the wellhead pressure, the more mass flow can be obtained due to an offset of frictional pressure to total delta P, as CO_2 flows downward.

Table 7.1 Wellbore steady state conditions during CO_2 injection

Steady State Conditions				
Cases	Mass Q	Wellhead		Bottom Hole
	kg/hr	P, (MPa)	T, (°C)	P, (MPa)
Base	98,323	16.0	0	27.2
	79,791	13.0		
	72,499	12.0		
	55,063	10.0		
	28,638	8.0		
Winter	30,744	3.1	-5	22.7
Summer	43,628	11.2	12	27.0

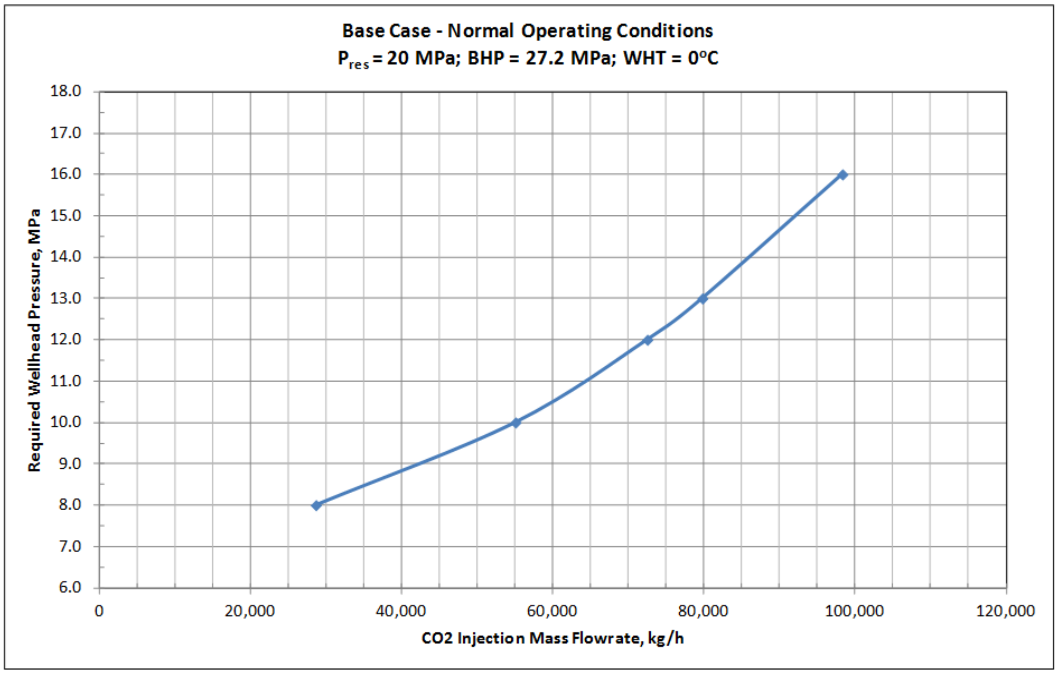

Figure 7.1 Normal operating conditions for base case

7.2. Transients Results

The magnitude of pressure surge depends on many factors; among those, is the change in the fluid velocity, an abrupt of change tends to cause high pressure spike. Usually, this can be seen when a valve at pipe outlet shuts off immediately, causing a sudden halt of flow.

In these cases, focusing only on the d/s side of the valve at wellhead, after it is shut, the fluid continues to flow out to reservoir until equilibrium (bottom hole and reservoir pressures are equal) is reached; meanwhile, a slight of sharp drop of pressures are seen just d/s of valve and tubing outlet.

As an example, see Figure 7.2, at wellhead (blue curve), pressure drops instantly from 12 MPa to 10 MPa (change of ~ -2 MPa) just after the valve is shut and the pressure wave is initiated to travel downward towards the bottom hole. After about 4.5 seconds, the pressure wave reaches the bottom hole, its pressure (red curve) drops sharply from 27.2 MPa to ~26.5 (change of ~ -0.7 MPa). These spikes are due to the initial downward swing of pressure wave; during the upward or return of the pressure wave, no significant surge is observed. As the pressure wave continues to travel back and forth, the trend of the pressure profile decreases until equilibrium is reached. Figure 7.3 shows the maximum and minimum pressure profiles of the tubing during transients.

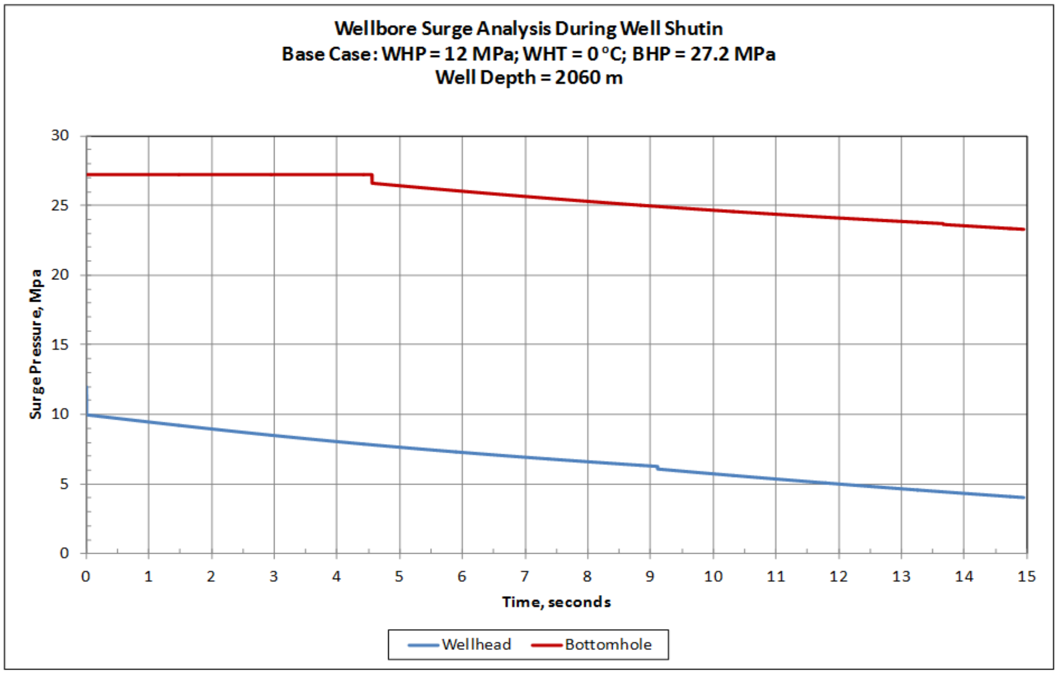

Figure 7.2 Wellhead and bottomhole trend curves during transients

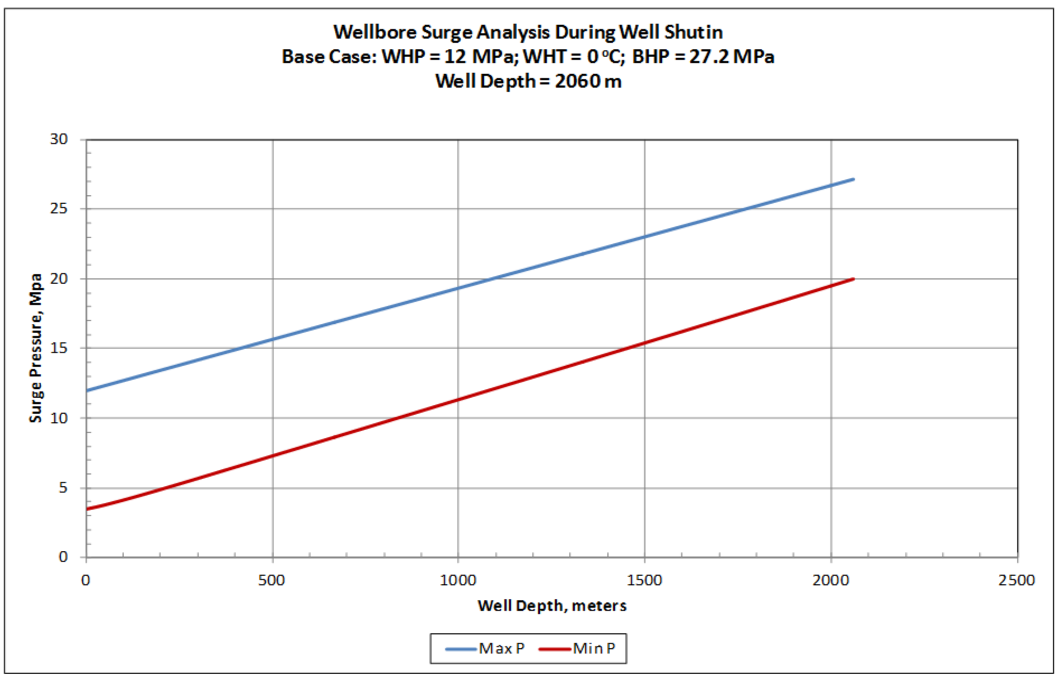

Figure 7.3 Maximum and minimum tubing pressure profiles of CO_2 injection during transients

Similar to Table 7.1, Table 7.2 summarizes the results of both steady state and wellbore pressure during transient. Note that in the transient section, the maximum and minimum pressures in the wellbore are shown in the first 2 columns; the maximum change in pressure in the wellbore occurs at tubing inlet and outlet and the data is listed in the last 2 columns.

Table 7.2 Results summary of steady state and transients analysis

Steady State Conditions					Wellbore Pressure During Transient			
Cases	Mass Q	Wellhead		Bottom Hole	Maximum	Minimum	Max Δ P @ Inlet	Max Δ P @ Outlet
	kg/hr	P, (MPa)	T, (^{o}C)	P, (MPa)	MPa	MPa	MPa	MPa
Base	98,323	16.0	0	27.2	27.2	3.4	-2.76	-0.36
	79,791	13.0			27.2	3.4	-2.29	-0.57
	72499*	12.0			27.2	3.4	-2.06	-0.65
	55,063	10.0			27.2	3.4	-1.55	-0.81
	28,638	8.0			27.2	3.4	-0.80	-0.85
Winter	30,744	3.1	-5	22.7	22.7	3.0	-0.10	-0.08
Summer	43,628	11.2	12	27.0	27.0	4.7	-1.03	-0.50

Note that, the case with an asterisk and yellow highlight was repeated, but with the wellhead valve closing time of 30 ms (instead of instantly or 1 ms). As a result, the maximum delta pressures at tubing inlet and outlet are -2.02 MPa and -0.65 MPa, respectively. The trend indicates that longer valve closing time results in less maximum delta pressure at wellhead; although, not a huge difference for this case compare with the 1 ms valve closing time case.

Previous findings from similar well shut-in case with water injection had indicated a backflow surge from the reservoir into the well which can result in sand loading or squishing into wellbore, an undesired problem for this process.

To demonstrate, a water injection case was performed using similar conditions as for CO_2, Figure 7.4 provides the maximum and minimum tubing pressure profiles. As can be seen, the minimum pressure at bottom hole (~2060 m) is 19.76 MPa, 0.24 MPa less than the reservoir pressure (20 MPa); an indication of a backflow into the tubing which is not seen for the CO_2 injection case (see Figure 7.3).

It is presumed that the bulk modulus of the fluids contributes to the differences. CO_2 is much more compressible and as a result, pressure wave travels slower with less magnitude during transients for the injection case, as compare to water. This is shown in Figure 7.5, for instance the bottomhole-CO2 (red) curve, by the time the pressure wave has made a second trip (around 13.5 seconds) to reach the bottomhole, the surge is pretty much dissipated.

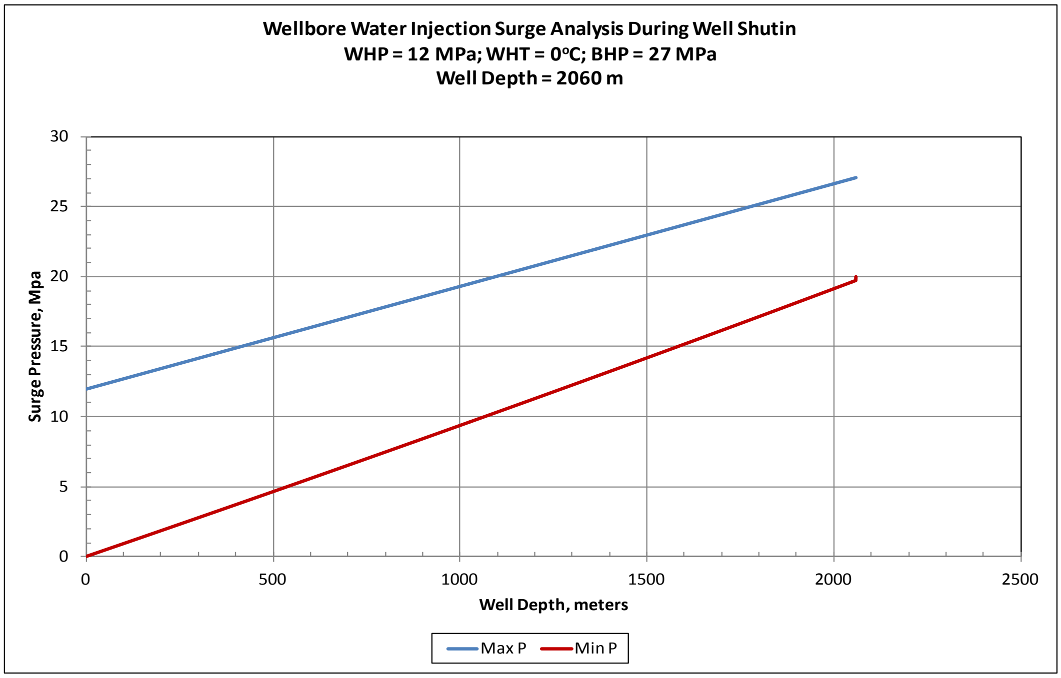

Figure 7.4 Maximum and minimum tubing pressure profiles of water injection during transients

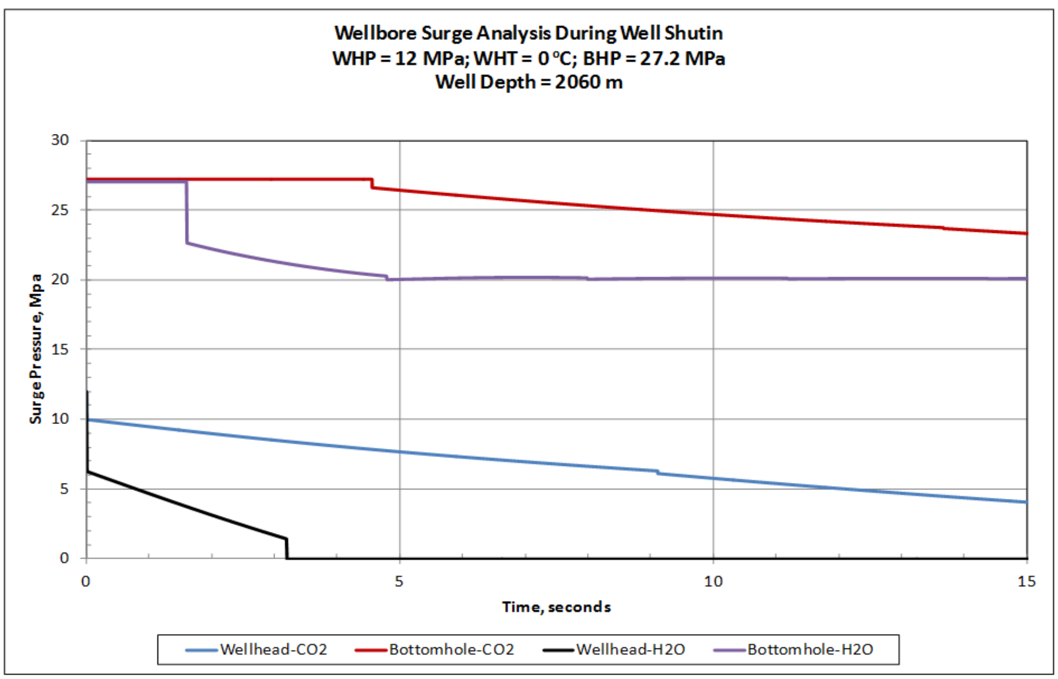

Figure 7.5 Wellhead and bottomhole pressure trend curves during transients for CO_2 and water injections

7.3. Conclusions

- In all considered CO_2 injection cases, no pressure surge exceeds the formation fracturing pressure of 30 MPa during instantaneous valve shut-in at wellhead.
- In all considered CO_2 injection cases, no indication of sand loading from the formation into wellbore during instantaneous valve shut-in at wellhead.
- Based on the results, formation damage or sand loading into wellbore due to instantaneous valve shut-in at wellhead is not expected.

8. WORKS CITED

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