

Integrity Management Approach to Reuse of Oil and Gas Pipelines for CO₂ Transportation

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ABSTRACT

With the ever increasing level of CO₂ production in today's world, new ways of reducing CO₂ emissions are being investigated. One option is the carbon capture method where CO₂ produced by power stations and other industries is captured and then stored by injection into wells. As part of this the transport options for the CO₂ from treatment to injection needs to be considered. In an attempt to further reduce emissions arising from the design and manufacture of new pipe lines, the reuse of existing decommissioned old oil and gas pipelines is being studied. In this study we are looking at a life cycle integrity management approach for the use of these decommissioned lines for CO₂ transportation. This study also assesses the financial implications of using old lines against the design and manufacture of new lines.

First and foremost this study looks at an evaluation of the condition of the decommissioned lines to determine if they can be economically used for transport of CO₂ either as liquid or as supercritical liquid. First the condition of the line is studied to determine if fracture initiation sites are present. If the lines do not show these initiation sites, fracture propagation with supercritical CO₂ is studied. The approach taken is a novel flow diagram similar to integrity management approaches used for oil and gas pipelines and encompasses risk assessment and initial inspection and procedure documentation plan.

1.0 Introduction

There is overwhelming evidence, that climate change will threaten economic growth and long-term prosperity. The intergovernmental panel on climate change (IPCC) suggests that to avoid the most catastrophic impacts of climate change, greenhouse gas (GHG) emissions should be reduced in the order of 50-80% below 1990's levels by 2050. To achieve these goals necessitates innovative changes in the short and medium-term in technology in all sectors of the economy. Among these technological developments Carbon Capture and Storage (CCS) has been considered as a key technique for reducing emissions substantially. To ensure the successful implementation of CCS it is recognized that transport of CO₂ via pipelines will play a key role in making the technology economically viable. The transportation of mostly pure CO₂ via pipeline is nothing new with world experience of CO₂ pipeline being about 7500km of which 6000km (3700 miles) are mostly large diameter and operational in the USA [1]. The use of CO₂ in these instances is not solely for CCS projects but also for Enhanced Oil Recovery (EOR).

If the captured CO₂ is not pure, it should be examined if a purification unit is affordable. If the costs are not too high, this extra process would lead to easier operation of the pipeline and it would also increase storage volume down-hole in the storage reservoir. On the other hand in most cases, the cost of purification is expensive and is not always possible especially at some offshore locations [2].

The transportation of CO₂ which includes some impurities has effects on the pipeline integrity as corrosion and other threats will differ due to the contaminants. Extra care has to be taken in the case of severe conditions such as high pressure & temperature, and sour service conditions.

There are no known standards or recommended practice in industry for the design and implementation of existing pipelines to transport CO₂. In order to make this possible, this paper studies the conditions, properties and behaviour of supercritical dense phase CO₂. The possible threats for transport of dense phase CO₂ containing contaminants are also examined [3; 4].

A risk based strategy is then developed to study the feasibility of overcoming these threats to allow the reuse of the pipelines. The issues studied are fracture control [5, 6, 7], internal corrosion with and without contaminants and external threats. The risk approach is studied as the likelihood and consequence of failure taking into account pipeline routing and condition of the line.

This paper discusses the integrity management strategy approach adapted from B31.8 to reuse of existing oil and gas pipelines to transport CO₂. The study involves the mitigation measure required which include fracture control methodology and the requirement for dehydration of the CO₂ to avoid internal corrosion issues. The focus is on the requirements of "material compatibility" to ensure that fracture initiation and potential propagation of running fractures are tackled along with internal corrosion mitigation during the re-design process.

2. Properties of CO₂ and Preferred Conditions for Its Transmission

Figure 1, schematically shows the pure diagram for CO₂. CO₂ can exist as a gas, liquid, or solid. At standard temperature and pressure (STP), CO₂ exists as a gas. At the triple point (5.11 bar, -56.4 °C) all phases exist in equilibrium. At the critical point (31.1°C, 73.8 bar) located upper right in the phase diagram for CO₂, the temperature and pressure at which the liquid and gaseous phases of a pure stable substance become identical. Above this point CO₂ exist as a supercritical or dense phase. Pipeline transmission of CO₂ over longer distances is considered most efficient when the CO₂ is in the supercritical dense phase, since in this phase the fluid has the density of a liquid and the viscosity and compressibility of a gas. The higher efficiency is due to the lower friction drop along the pipeline per unit mass of CO₂ when compared to the transmission of the fluid as a gas or in a gas-liquid phase.

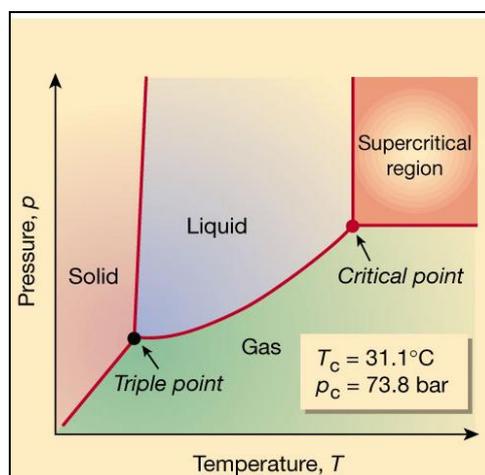


Figure.1 Phase Diagram for Pure CO₂[8]

Effects of Impurities on CO₂ Phase Diagram

It is anticipated that 'captured' CO₂ will include a series of impurities depending on the capture technology (pre-combustion, post-combustion or oxy-fuel processes). Race et al [9] discusses the potential effect of these impurities (SO_x, NO_x, H₂ and Ar) on the phase diagram for CO₂.

Impurities in the CO₂ have an effect on the following:

A- Design of equipment; e.g. pumps and compressors:

Suction pressure settings and compression strategy need to avoid operation in the two phase region.

B- Toxicity of impurities:

The concentration may determine the safe exposure limits for the fluid instead of CO₂ concentration. Impurities can also affect the design and operation of blow down facilities. Also H₂S is a combustible impurity and cannot be vented to atmosphere if present in CO₂. A solution can be to connect the blow down facility to a flare [10]

C-Transport capacity:

Impurities reduce the transport capacity of the pipeline [11]

D-Vapour pressure:

Rising of the vapour pressure means that higher minimum entrance pressure or shorter recompression/booster station intervals are needed to keep the fluid in dense phase.

E- Pipeline integrity:

The vapour pressure sets the decompression pressure at a pipeline break. Thus a high decompression pressure can facilitate further propagation of a fracture. Presence of atomic hydrogen can lead to hydrogen embrittlement of the pipeline steel or hydrogen induced cracking. Sulphide Stress Cracking (SSC) has to be taken into account with presence of H₂S (requirement for 'sour service').

F- Corrosion:

The water solubility and hydrate formation conditions provide the stream remains extremely dry, the gas stream should remain non-corrosive, therefore impurities should have minimised.

The effect of impurities is generally to increase the width of the phase envelope and results in the formation of a two phase gas-liquid region. Some impurity combinations tend to cause a large increase on the envelope (e.g. H₂ and NO₂) whilst others show a much smaller increase (e.g. N₂ and H₂S). Also sulphide stress cracking (SSC) has to be taken into account with presence of H₂S (i.e. requirement for 'sour service'). Most extensive work published is the EU Dynamis14 study, proposing a CO₂ specification based upon calculations, literature reviews and expert opinion, represented at Table 1.

Table 1. DYNAMIS CO₂ quality recommendations [12]

Compound	Concentration Limit	Remarks
H ₂ S	200 ppm	Health and safety considerations
CO	2000 ppm	Health and safety considerations
CH ₄	Aquifer <4 vol%, EOR <2 vol% (all non cond. gases)	Like ENCAP
CO ₂	>95%	Results of other compounds in CO ₂
N ₂ , Ar, H ₂	<4 vol% (all non cond. gases)	Like ENCAP

3. Scope / Reason

The research activities concentrate on development of the capture technologies to reduce cost, and on assessing the technical feasibility of injecting and monitoring the CO₂ within the geological reservoirs themselves. Only a little work is being conducted which addresses integrity of the facilities intended for this purpose and, in particular, corrosion of transport lines and wellbore materials. Also there is relatively little experience in pipeline transportation of dense phase CO₂, in the scale that will be required for CCS. In addition, current pipeline standards are recognised as not being fully applicable in this area. This combines to create a significant challenge for CCS pipeline stakeholders to utilise existing infrastructure to transport CO₂. This is considered an attractive option because 1) it eliminates the need to manufacture new pipelines and further reduces carbon footprint 2) It benefits the operator both economically and commercially.

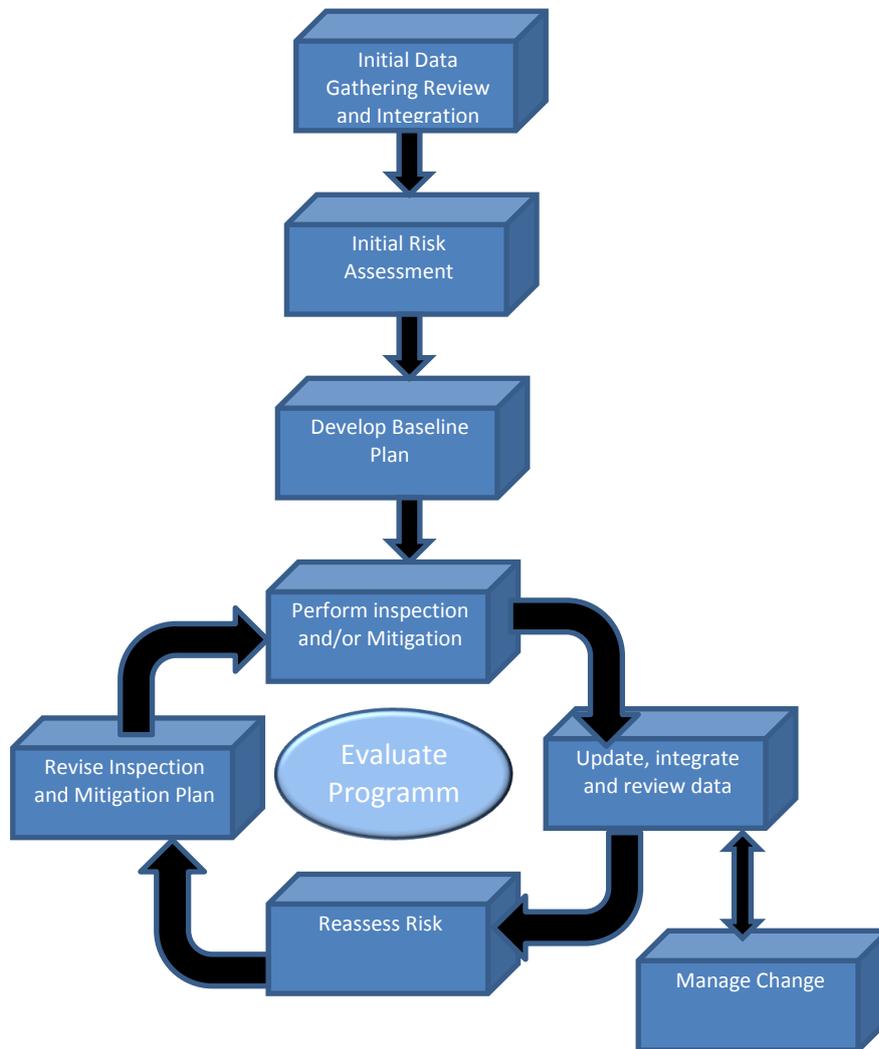
4. Integrity Management Plan

All of the threats associated with the use of pipeline for CO₂ can be assessed in risk assessment program.

The risk is a function of the likelihood of an event or condition to lead to a release, and the consequence in the event of a release. Both components of risk must be considered when conducting a risk assessment and in making risk-based decisions [13].

The program will follow the initial steps from the program as shown in Figure 1.

Figure 1. Integrity Management Plan



Integrity Management Plan Internal / External Corrosion

For this study we have focussed on the first three steps of this process data gathering, initial risk assessment and Development of baseline plan

4.1 Data gathering process Condition

For this study we are taking a model system in the desert which will have the aim of capturing more than 20 MMTPA CO₂ from oil and gas processing plants, existing and future power plants and all other industrial facilities that have the capability to capture and store the CO₂ they produce. The captured CO₂ can be delivered via de-commissioned pipeline network to the sites where it will be injected into wells for Enhanced Oil Recovery (EOR) or storage. This CO₂ can also replace the natural gas that is currently used in the EOR technologies thereby reducing the carbon footprint.

This paper mainly discuss the CO₂ transport on the assumption that the captured CO₂ will be pure, but if the captured CO₂ contains other impurities resulting from the processes from which it emanated, then that situation will required a separate investigation the design stage. This is because the

properties of the impure CO₂ and gas decompression behaviour of the impure CO₂ arising from the impurities in the gas is not fully known.

4.2 Risk Assessment

The risk assessment is based on Identification of the risk associated with the reuse of pipelines for Dense phase CO₂ and then a quantitative risk assessment based on consequence and likelihood of failure [14, 15].

5. The Threats

The three most prominent threats associated with transporting CO₂ in existing decommissioned pipelines can be listed below:

- Corrosion – both internal and external
- Defects/ fracture
- Materials

Corrosion – both internal and external

Dry CO₂ does not react with carbon steel within a normal temperature range of 0 to 60°C. CO₂ with free water or brines will dissolve to form an aqueous phase which is potentially conducive to internal corrosion in carbon steel pipelines. For both Carbon Capture and Storage (CCS) and Enhanced Oil Recovery (EOR) processes, although the injected high pressure CO₂ may be fairly dry, as soon as it comes into contact with any water in the injection zone it will form carbonic acid (H₂CO₃) and become highly corrosive to mild steel. Should this medium come into contact the wellbore steel, severe general and/or localized corrosion attack would be expected to occur.

Parameters affecting CO₂ corrosion are water wetting, partial pressure, temperature, pH, flow, carbonate scales and brines composition. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO₂ in a pipeline and also the influence the various CO₂ compositions will have on the corrosion rates. Moreover there is a need to investigate hydrate formation conditions with CO₂ near and below water saturated conditions below 10°C. The acceptable response time will be system specific and depend on the corrosion rate and corrosion allowance. The presence of other species like SO_x, NO_x, O₂ and H₂S, either pre-existing in the injection zone or as impurities in the CO₂, would also be expected to play a role in the corrosion processes. The problem is that the exact state of the CO₂ rich phase after injection is not precisely known, and that the corrosion process of steel in aqueous supercritical CO₂ has not been characterized until now. Addition of complicating factors like protective surface films, the use of corrosion inhibitors, composition of formation waters, steel type, the corrosion history of the casing material and the presence of impurities, increases the complexity of the phenomena. The concentration of these impurities can be high and it is expected that they can increase the corrosion rate significantly with higher CO₂ contribution. Also the understanding of the effect of impurities on high pressure CO₂ corrosion is still very limited because the nature of the interaction with carbon steel is complicated.

A number of corrosion inhibitors have been developed to mitigate CO₂ corrosion in typical oil and gas field environments, but their use would not be practical to mitigate corrosion should water be allowed to enter the pipelines especially at high partial pressures. CO₂ with an amount of H₂S in the gas, water in the pipeline would also present a risk of sulphide-stress cracking. To prevent H₂S damage, line pipe suitable for sour service must be specified. Internal corrosion will cause safety concerns and reduce the design life of the pipeline.

Pipeline experiencing from external corrosion and coating damage can also be a high risk corrosion mechanism. The possible causes of external corrosion are, Sulphate Reducing Bacteria (SRB), pitting corrosion due to interference with cathodic protection systems. This type of external corrosion processes can generally be dealt by designing and implementing a suitable cathodic protection system.

5.1 Defects

Transmission pipelines with thin wall thickness (less than 25mm) have been produced for many years. They are usually buried or subsea, the failure of part wall defects in pipelines material is usually by tensile necking of the ligament remaining below the defect. Sharper defects in parent material, such as scratches or gouges, failure by progressive ductile crack growth. Defects in older pipelines, and the thicker walled pipelines, will generally show ductile fracture initiation. Defect in longitudinal (i.e. factory produced) pipelines welds usually fail by a ductile fracture mechanism, although defects in circumferential welds can fail by brittle fracture and may require brittle fracture calculations [16, 17; 18, 19]. In order to safely determine the suitability of a pipeline for re-use, an understanding of the “as-found” conditions and confidence in the data generated from an inspection programme are key for an operator to determine future integrity and remaining life assessment for the pipeline. Several methodologies are available for the defect acceptance based on Fitness For Purpose (FFP) evaluation and Engineering Critical Assessment (ECA). Both evaluation can provide safe operating limits for a pipeline in terms of maximum allowable operating pressures, fatigue cycle before failure, etc. The most common framework for defect assessment criteria is based on Battelle formulas derived from semi-empirical approaches which provide criteria for assessing the resistance of steel pipelines to initiation of fracture from axial defects. When in line inspection data is available, methodologies described in ANSI/ASME B31G modified ASME B31G, and DNV RP-F101 can be used for the evaluation of corroded pipelines to determine failure pressure and maximum allowable operating pressure of the section with metal loss reported.

5.2 Cracking

It is a known phenomenon that in the presence of hydrogen sulphide issues associated with cracking of pipeline materials should be investigated.

However, based on the NACE MR0175 conditions, a H₂S minimum partial pressure of 0.05psi is required for a system to be regarded as sour and furthermore for any issues related to cracking to occur. Hence, pipeline materials are highly susceptible to corrosion related issues associated with cracking, when exposed to sour operating conditions of H₂S partial pressures greater than 0.05psi.

A sour service environment is, in general, considered as any environment containing H₂S. H₂S in the presence of water may result in damage to carbon steel pipelines in form of corrosion, cracking, or blistering. The effects of H₂S on steels could be classified as those that require external stress, such as sulphide stress cracking (SSC), and those that do not, such as hydrogen induced cracking (HIC), and corrosion. The presence of carbon dioxide in the sour environment tends to increase the corrosion rate in the steel; it may also increase the susceptibility of the steel to both SSC and HIC, with the effect on HIC being more pronounced.

The pipelines that have been considered for re-use should be carefully studied for their suitability for sour service compliant and operating conditions.

5.3 Material

Understanding materials' behaviour is critical for the successful and cost effective operation of existing materials integrity in representative high pressure and supercritical CO₂ to enable confident material selection, safe operation and accurate remaining life assessment to avoid the expensive consequences of unexpected failure, as well as removal and replacement.

Although there is considerable experience of testing material in low pressure CO₂, there are no standard test methods and few data for supercritical CO₂. Data are required on the resistance of parent and weld metallic materials. There are no data on the effect of supercritical CO₂ on preferential weld corrosion (PWC).

Supercritical CO₂ causes a large cooling effect upon rapid pressure release and this can result in pipeline temperatures within the lower shelf (brittle fracture) range. When combined with time required for decompression, this leads to an increased risk of running fracture. Therefore material loss and through-wall corrosion can pose a significant risk to the integrity of the whole system. Pipeline with fluids containing hydrogen sulphide shall be evaluated for sour service according to ISO 15156 as they may be exposed to conditions where formation of free water may not be avoided.

6. Quantitative Risk Assessment

The quantitative risk assessment is based on evaluation of the consequences and the likelihood of the threat leading to degradation of the pipe material.

6.1 Consequence

The consequence depends upon the location of the pipeline and its effect on safety, environment and economic issues.

6.2 Safety

Although CO₂ is a toxic gas the consequence of the safety issues will depend upon the location of the pipeline. For instance for an offshore pipeline if a failure occurs the water surrounding the pipeline will to some extent absorb or disperse the CO₂ without the toxic gas being released into an area where it could cause harm. Even in this case the approaches to manned platform would have a higher consequence than a rupture of pipeline a distance away. However compared to an onshore pipeline the consequence for an offshore pipeline failure is likely to be much lower. For onshore pipeline the location is also something that should be considered. CO₂ is a dense gas and will sit at low points causing a hazard, if this is in the remote desert this is less likely to cause harm than if it is close to village or town therefore the routing of the pipeline needs to be addressed when considering the consequence of release on safety.

6.3 Environment

The evaluation of the environmental consequence for a CO₂ pipeline is difficult to address. The pipeline needs to be used to transport the CO₂ and its impact on the environment so it would seem that a failure in the line would have high environmental consequence and would require the plant producing the carbon dioxide to be shut down. The authors wonder if it would be a great consequence on the environment, however it could be argued that in the case of power generation the shortfall would need to be made up from other sources which may not have carbon capture facilities thus having a higher impact. It can be concluded that this is a criteria which really need to be assessed on a case by case basis.

For the model system under study in this paper it is assessed that in the Middle East where power generation can be made up from other sources it would not have great impact on the environment.

6.4 Economic

The economic consequence would be based on the fines and or carbon trading cost that will be required to make up short fall. This is significant and therefore a consideration when comparing risk between safety, environment and economics.

6.5 Ranking of Consequence

As an example for this paper the authors have assigned consequence levels of A to E, these relate to the consequences as shown in Table 2.

Table 2 Consequence coding and discussion

Consequence Coding	Safety	Environment	Economic
1	No release	No effect	No effect
2	Minor release in Remote location	Some effect alternative low carbon release resources used	Short term loss in power generation
3	Major release in Remote location possible health effects	High CO ₂ release shortfall made up by low CO ₂ release power generation	Long term loss in power generation
4	Minor release in populated location, No health effects	Small release of Carbon Dioxide with short fall made up from high CO ₂ release resources	Short term loss in power generation with fines and carbon trading requirement
5	Major release in populated location , some health effects	Large release of Carbon Dioxide with short fall made up from high CO ₂ release resources	Long term loss in power generation with fines and carbon trading requirement

6.6 Likelihood of release

The likelihood of release is based on the threat as discussed in section and if they will occur. For the risk assessment the unmitigated threats are assessed to determine if a mitigation process is required to make the risk acceptable.

For our paper the likelihood is split into 5 regions as shown in Table 3.

Table 3 Likelihood coding and discussion

Code	Discussion
1	Will not happen
2	Unlikely
3	Could happen
4	Probable to happen
5	Will happen

6.7 Overall Risk Ranking

The overall risk ranking evaluation is performed by using a Boston Square.

This plot allows the risk to be assessed before and after mitigation measures are in place. The product of consequence and likelihood is calculated and noted in the Matrix. The assessment includes ranking the products as acceptable and unacceptable although a likelihood of 5 is always unacceptable. For our process the authors assessed that the acceptable product is 6 with an intermediate level between 6 and 9, any threat deemed to be below 6 does not need mitigation or any further mitigation if this is the result after mitigation is put in place. If the risk is between 7 and 9 it is recommended that

mitigation is carried out although engineering judgment on cost verses benefit can be used at this point.

6.8 Risk assessment

For the threats discussed in section a workshop was carried out to assess the various threats and the consequence and likelihood of failure.

Up front the consequences of a failure were assessed based on the line being:-

- Short pipeline
- Desert unpopulated location
- Middle East location
- No carbon trading requirements
- Other low carbon power sources available

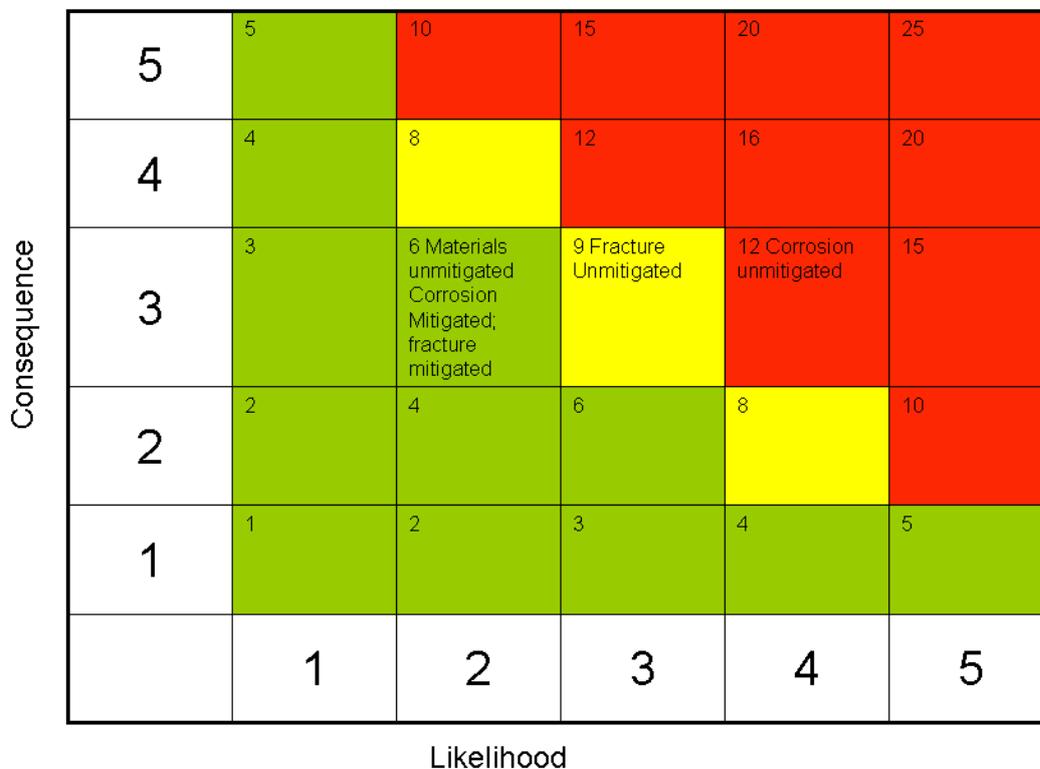
From this the consequences of failure were assessed as

- Safety 3
- Environment 3
- Economic 2

Therefore the consequence was driven by safety and environmental concerns.

The likelihood of failure is assessed in table 4 shown in Appendix 1. The results from this have been transferred to a Boston square diagram as shown in Figure 2.

Figure 2 Boston square diagram showing risk assessment for re-use of pipeline for dense phase CO2



The data in Figure 2 shows that the three threats under study can be controlled so that the risk associated can be brought to an acceptable level.

The way that the threats can be controlled is by use of mitigation measures be they physical mitigation such as fracture arrestors or inspection programs and operational procedures.

7. Base line plan

The baseline plan is derived from the output of the risk assessment process and can be discussed against the possible threats.

7.1 Corrosion

The mitigation methods discussed in the risk assessment for the corrosion threat revolve around the elimination of water from the CO₂ stream. The baseline plan would therefore to develop the following monitoring and documentation to ensure elimination of water and control of contaminants.

- Procedures to be written to cover
 - Monitoring of stream for water and contaminant content
 - Development of criteria (Key performance indicators) to measure to ensure water and contaminants are controlled, including setting suitable limits.
 - Development of procedures to put in place in case of upset conditions including shutting down of pipeline and power plant if required.
 - Requirements of reports to cover these operations.

7.2 Fracture control

From the risk assessment the fracture control mitigation requirements include understanding the condition of the pipeline and addressing suitability for dense phase use. To do this the following actions need to be carried out.

- Inspection of the line by intelligent pig or external studies.
- Detection of defects in the line from the inspections.
- Evaluation of the defects to determine fitness for purpose of the line for use with Dense Phase CO₂, including fracture propagation analysis by Batelle 2 curve method or alternative techniques [20,21]
- Identification of repairs or requirement for fracture arrestors to allow use.
- Scheduling of repairs or installation of fracture arrestors if required.

7.3 Materials

It has been assumed that the materials of the pipeline is suitable for use, however this needs to be confirmed.

To carry this out the wall thickness needs to be evaluated to see if it can withstand the pressure for the new use

If sour conditions are possible the suitability of the materials for this use needs to be evaluated versus NACE MR0175/ ISO 15156 standards.

8. Discussion

The paper discusses some of the issues that will be encountered when considering a pipeline for reuse with dense phase CO₂ for CCS projects. Although reuse is mentioned there are also considerations that will need to be addressed when designing new pipelines. These can be formulated into an integrity management approach which will include:-

- Obtaining current data and the system requirements

- Performing risk assessments to determine the risk associated with various threats and how these need to be mitigated to ensure safe use of the line.
- Setting of the baseline inspection and operational procedures to ensure these threats are mitigated in the appropriate manner to allow full life cycle of the project to be achieved without safety, environmental or economic issues being encountered.

Of particular attention is the corrosion issues and the need to completely eliminate water from the system, with pure CO₂ and the high pressure required to keep the system in dense or supercritical flow any water would mean a highly corrosive environment would be present. Procedures to ensure that water is controlled or in upset conditions shut down and treat to remove the water will need to be in place.

Another issue that is highlighted is fracture initiation and propagation due to supercritical CO₂. This will need to be evaluated by thorough inspection before reuse and the installation of fracture arrestors and or repairs if needed.

9. Conclusions

- This paper shows that reuse of pipelines for use with dense phase or supercritical CO₂ can be carried out.
- An integrity management approach can be adapted to assess suitability of a pipeline to develop a baseline plan of action.
- Data gathering and risk assessments are key to development of the plan and will address any possible issues that will need to be attended to for reuse of a pipeline.
- The use of this approach should allow the reuse of old pipeline further enhancing the CCS project profile by saving on manufacture of new materials and recycling of old pipelines.

10. References

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Appendix 1

Threat	Comments	Unmitigated Likelihood	Mitigation measures	Mitigated Likelihood	Consequence			Worse case mitigated Risk
					Safety	Environment	Economic	
Corrosion	High CO ₂ content Impurities High pressure Water content	4	Dehydration Scrubbing	2	3	3	2	6
Fracture	Fracture propagation CO ₂ decompression Steel strength	3	Inspection of pipeline condition FFP	2	3	3	2	6
Materials	Carbon steel Defects	2	Inspection for pipeline defects		3	3	2	6