# OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE

**Report: 2016/04**

**March 2016**

## INTERNATIONAL ENERGY AGENCY

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**OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE (IEA/CON/13/218)**

## Key Messages

- Large point sources of $CO_2$ can deliver relatively pure 99.7% $CO_2$ after capture and dehydration. However, it is important to recognise that many large-scale industrial processes that generate $CO_2$ emissions are cyclical and intermittent, therefore, to ensure a consistent and reliable $CO_2$ supply integrated pipeline networks will be essential.
- Experience from the United States clearly demonstrates that $CO_2$ with a high level of purity can be effectively and safely delivered using integrated pipeline networks.
- Networks can be a useful means to control flow in a pipeline and can also act as a buffer by supplying $CO_2$ from several sources to a number of different sinks. Multiple sources also mean that there is less reliance on a single source and intermittent supply from different sources can be accommodated. $CO_2$ can also be temporarily compressed or 'packed' into pipelines as a short term measure.
- This study has shown that most North American $CO_2$ pipelines are overdesigned for their current application. They are designed for higher flow rates and operating pressures through the use of thicker walls and larger diameters. Future pipeline networks can take advantage of this experience if there is an intention for increased capacity in the future.
- Impurities particularly $H_2O$ and $O_2$, can have negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. The density and viscosity of fluids can also be affected. Non-condensables like $N_2$, $O_2$, Ar, $CH_4$ and $H_2$ should be separately limited to <4% because their presence increases the amount of compression work. Compression and transport of $CO_2$ for $CO_2$-EOR use in the United States has shown that impurities are not likely to cause transport problems provided $CO_2$ stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).
- The most significant effect on transport and injection of $CO_2$ is the water content. The Kinder Morgan specification for pipeline transport of $CO_2$ is a 600 ppm by weight for $H_2O$ and 10 ppm by weight for $O_2$. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of chemical dryers such as monoethylene glycol.
- Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects. Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.
- $CO_2$ storage in deep saline formations can be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry.
- $CO_2$-EOR relies on controlling pressure and flow rate conditions to optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions the precipitation of minerals or asphaltenes (high molecular weight compounds such as bitumen) or changes in formation fluid saturation properties can occur. Reservoir permeability can be reduced as a result. This study has found that experienced operators can plan for intermittency in both the supply of $CO_2$ and in $CO_2$ EOR operations.

## Background to the study

The optimisation of carbon capture and storage (CCS) projects in terms of cost and efficiency requires one or more large scale point sources of captured $CO_2$ which can be transported via a pressurized $CO_2$

pipeline to reservoirs with suitable storage properties such as high permeability and known capacity. In many countries where CCS projects are under evaluation, $CO_2$ will be captured from fossil-fuel power stations. Over the last 20 years there has been a trend towards deregulation of the electricity supply market, and an expanding contribution from intermittent renewable forms of electricity production. Both these factors have led to a greater demand for flexible operation of power plant, and often at a short notice, to maximise the revenue and to meet regulatory requirements. Cyclical and intermittent operation of power plants will increase plant operation and increase plant operating costs. Consequently, the rate of captured $CO_2$ supply for transportation will also be affected, although the magnitude of this effect will depend on the extent of any interconnected pipeline network, multiple sources of captured $CO_2$ and rates of supply from different sources.

$CO_2$ transportation pipelines will need to be connected to $CO_2$ capture plants at power stations or other point sources (such has heavy industries) that will link them to potential $CO_2$ storage reservoirs. The ability of $CO_2$ pipelines to operate flexibly at higher pressures to maintain $CO_2$ in supercritical phase, and the technical implications of this mode of operation, need to be understood. The time duration to reach the complete supercritical phase in $CO_2$ pipeline will depend on the temperature and other parameters including the presence of impurities particularly the presence of water. In a supercritical phase, and at maximum operational pressure, line packing may be an operational option but constrained to a comparatively short period of a few hours before the system reverts to a standby mode which might include venting of $CO_2$ to atmosphere.

In addition to pipeline operation the composition of $CO_2$ from a variety of different sources has been reviewed to explore the potential impact on variable composition and impurities. $CO_2$ can be captured from various industrial processes and emission sources such as power generation, oil refining, iron and steel, cement etc. This will affect the type and concentration of impurities in captured $CO_2$. The presence of various impurities within the captured $CO_2$ needs to be taken into account because of the effects on Pressure Vapour Temperature (PVT) conditions. The fluctuations in supply from different industrial sources and power generation may also have an impact on transport and storage. The magnitude and the ability to manage injection programmes also needs to be understood. Diurnal swings in $CO_2$ output may be frequent; consequently system stability, including PVT balance, needs to be controlled to ensure that optimum transmission and injection conditions can be maintained and instability avoided.

There is also potential for hydrate formation in the immediate proximity of the wellbore due to the presence of formation water. The PVT conditions that could arise from flexible operation, and the presence of impurities have formed part of this investigation.

This study has reviewed how flexible $CO_2$ supplies might have an impact on both $CO_2$-EOR operations and permanent storage in depleted oil and gas fields and deep saline formations. $CO_2$ injection programmes for large scale geological storage and $CO_2$-EOR will have different objectives. Historically, the driver for using $CO_2$ for $CO_2$-EOR has been economic rather than environmental. The $CO_2$ injection rate needs to be optimized to enhance production without causing early breakthrough. The initial stages of injection will require much more $CO_2$ than in the later stages of recovery, as the reservoir is saturated and the $CO_2$ produced with the oil is recycled back into the reservoir. Therefore, the timing of the availability of the $CO_2$ is crucial. There is extensive experience of the use of $CO_2$ for $CO_2$-EOR, mainly in the United States, which has provided relevant detailed background.

In contrast, large scale $CO_2$ storage in depleted oil fields, and large saline aquifers, needs to maximize reservoir capacity with potentially long term injection over several years, and at higher pressure, compared with $CO_2$-EOR. The reservoir pressure needs to be controlled to avoid damage to the caprock or cause instability in faults. In both cases careful planning is required to ensure that the pressure/ temperature conditions of the $CO_2$ are compatible with the reservoir.

## Scope of work

This study has reviewed different transport and storage scenarios to reflect the range of full-scale commercial operations. In addition to a wide ranging literature review a survey of industrial, utility, pipeline and $CO_2$-EOR operators was also conducted to obtain their insights of $CO_2$ transport and storage. Owing to the sensitivity of these commercial operations it has not been possible to attribute background information to either individuals or their companies. Anonymity has not prevented the inclusion of real world data on exhaust gas composition from different sources including power generation (coal and natural gas), oil refining, gas processing, cement, hydrogen production, and ethanol production. It also includes background information on actual $CO_2$ pipeline operation, including network hubs, and $CO_2$ $CO_2$-EOR experience in the United States. Experience from different industrial scale injection projects such as Sleipner, Snøhvit and In Salah, has been included. The study has investigated how flexible operation affects $CO_2$ storage and the measures adopted to accommodate intermittent supply.

There are a series of prioritized recommendations based on the gaps in knowledge.

## Findings of the Study

Five full-scale commercial transport-storage examples including Sleipner, Snøhvit, In Salah, Weyburn and Decatur were reviewed. All these projects experienced mass flow variability or interruptions in flow. Mitigation strategies implemented at these sites have accommodated the effects of intermittent flow.

Different industrial processes produce $CO_2$ streams with different compositions. The different $CO_2$ capture method can also affect the composition of the flue stream.

Approximately 28% of global $CO_2$ emissions come from coal-fired power plants. After scrubbing and dehydration relatively pure 99.7% $CO_2$ can be achieved. The amount of $CO_2$ produced by a power plant depends on the electricity demand. Research conducted as part of this study revealed that $CO_2$ emissions from a power plant can be fairly constant for 8-12 hours with only minimal change. At other times the load change fluctuate higher or lower by a rate of 1-2% a minute. This rate of change can shift in the same direction for as long as 30-45 minutes. Electricity generation is governed by market demand which means that plant operators are not able to predict the load on an hourly basis. However, operators who responded to this study commented that the $CO_2$ concentrations in the flue gas are fairly constant across the load range, varying from 10% to 12%.

In contrast the flue composition of cement plants, based on investigations by this study, varies widely with $CO_2$ forming between 14% - 33%. Capture technology and scrubbing can deliver comparatively pure $CO_2$ but cement plants operate intermittently depending on demand for the product consequently their integration into a $CO_2$ supply network would be challenging, particularly as they can be periodically shut down for months. Petroleum refineries can individually produce substantial volumes of $CO_2$, but from several different processes. $CO_2$ purities of 95% to 99% are feasible. There are two examples of refineries, the Pernis refinery in Rotterdam and Valero’s refinery in Port Arthur Texas, that have $CO_2$ capture facilities from hydrogen production unit syngas streams. $CO_2$ is delivered to pipeline networks in both cases.

Modelling results have indicated that the presence of certain impurities in the $CO_2$ stream may cause problems with the maintenance of single-phase flow within a $CO_2$ pipeline, particularly the presence of water which can form corrosive carbonic acid and hydrates that can obstruct pipelines. Impurities change the physical and therefore the transport properties of $CO_2$. Changes in stream hydraulics changes the number of compressors and therefore the power demand to pump $CO_2$.

Depending on the type and concentration of impurities there can be negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. However, compression and transport of $CO_2$ for $CO_2$-EOR use in the United States has shown that impurities are not likely to cause transport problems provided $CO_2$ stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).

The economics of $CO_2$ transport favour movement in a supercritical phase as opposed to a vapour phase which would require a considerably larger diameter pipeline.

Impurities can have a significant effect on temperature and pressure conditions but also on density and viscosity of fluids. Some combinations can cause higher pressure and temperature drops for a given length of pipeline. Sudden temperature drops can cause embrittlement and/or hydrate formation both of which can damage pipelines. Some contaminants, or combinations, have specific effects relative to a $CO_2$ stream and its transport or end use. Examples include:

- $N_2$, $CH_4$ and $H_2$ all have lower critical temperatures than $CO_2$ which would lead to increased pipe strength to minimise ductile potential.
- Noncondensables like $N_2$, $O_2$, Ar, $CH_4$ and $H_2$ should be limited to <4% because their presence increases the amount of compression work.
- The concentration of $O_2$ in $CO_2$ should be limited to eliminate the potential for exothermic reactions with hydrocarbons in CO2-EOR operations. $N_2$, $H_2$ and $CH_4$ increase the miscibility pressure during CO2-EOR activities and should be limited.

The most significant effect on transport and injection of $CO_2$ is the water content. The formation of carbonic acid can corrode a pipeline at a rate of 1-2mm within 2 weeks. Supercritical $CO_2$ can store several hundred Parts per million (ppm) of water depending on its temperature which can lead to the formation of hydrates that can cause obstructive plugs. Pressure and temperature conditions within a pipe caused by variable flow conditions can have a substantial effect on corrosion and hydrate formation. However, pressure control systems are designed and operated to ensure operating conditions avoid deleterious effects. The topographic variability over the course of a pipeline route can lead to low spots where two-phase flow can occur leading to the pooling of the supercritical phase. Two-phase flow seems more likely to occur when the pipe is oversized relative to the amount of $CO_2$ that is transported. Another condition that should be avoided is rapid pressure oscillations which can lead to cavitation (the formation of vapour cavities or voids in a liquid caused by rapid pressure changes where the pressure is relatively low. When voids are then subjected to higher pressure, they can implode and cause intense shockwaves).

Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.

$CO_2$ pipeline design needs to take account of the source and sink or destination of the $CO_2$. This investigation has revealed that most $CO_2$ pipelines currently in existence in North America are overdesigned for their current application. They are designed for higher flow rates and operating pressures through the use of thicker walls and larger diameters. For example, the Denbury Greencore Pipeline began operation with a capacity of 0.96 M tonnes / year but was designed to carry up to 13.9 M tonnes /year. The additional pipeline dimension enables the company to expand its network's carrying capacity.

$CO_2$ pipeline networks and hubs can be controlled so that the supply and demand of $CO_2$ can be regulated. Temporary storage can be achieved by increasing the gas pressure and loading more gas into a pipeline a process known as pipeline packing. This procedure is more effective at lower pressure. For example, the capacity of supercritical $CO_2$ packed into a 320 km 600mm diameter pipeline could be increased by almost 8,300 tonnes if the pressure was raised from 8.4 MPa to 10.4 MPa. Increasing the pressure from 16.0 MPa to 18.8MPa would only increase capacity by 2,900 tonnes. The other advantage of a network system is that several sources can be accessed so that reliance does not depend on a single or limited supply option.

The largest $CO_2$ hub in the world is the Denver City hub in eastern Texas. It distributes $CO_2$ from the 808 km Cortez Pipeline which has a capacity of 30.4 $Mm^3/d$ and a planned expansion to 56 $Mm^3/d$ (61.125 ktonnes day). Other hubs are established in Texas (McCarney) and Rotterdam in the Netherlands. The UK is planning to develop a Central North Sea CCS hub to transport $CO_2$ from large power plants and other industrial point sources in the Yorkshire and Humber regions of the country. A government-industry partnership in Western Australia is also planning a network, the Collie-South West $CO_2$ Geosequestration Hub.

Networks can be a useful means to control flow in a pipeline. They can also act as a buffer by supplying $CO_2$ from several sources to a number of different sinks. Multiple sources also mean that there is less reliance on a single source and intermittent supply can be accommodated. Viable pressure and flow conditions in pipelines can be controlled by remote terminal units (RTUs) that communicate with sensors and actuators as well as Supervisory Control and Data Acquisition (SCADA) systems. SCADA systems co-ordinate responses to variable flow conditions by transmitting command signals to RTUs. This form of control can also estimate the physical state of a fluid and therefore minimise pressure drops. SCADAs are used to estimate the volume of $CO_2$ that can be accepted or delivered before the pressure limits are exceed. Leaks, ruptures or other losses can also be detected.

The impact of intermittent flow on storage related to $CO_2$-EOR, depleted oil and gas reservoirs and deep saline formations was also investigated. $CO_2$-$CO_2$-EOR relies on controlling pressure and flow rate conditions that optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions attendant drops in oil production could occur and in some circumstances the precipitation of minerals or asphaltenes or changes in formation fluid saturation properties could also occur. The reservoir permeability could be reduced as a result. This investigation found that experienced operators can plan for intermittency and use strategies such as water injection and pipeline packing to manage impacts. $CO_2$-EOR projects are designed with a safety margin on both pressure and capacity that is significantly above operation pressure. These schemes are also designed for additional $CO_2$ capacity and include recycled $CO_2$. Intermittency can be mitigated with the use of recycled $CO_2$. However, if wells are shut in the value of lost oil production can range from tens of thousands to millions of dollars a day in lost production depending on the size of the field.

Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects. The Joule-Thomson effects caused by pressure-drop can also lead to freeze-up of valves and joints. The use of standard oil and gas industry protocols can limit the impact of intermittent operation.

$CO_2$ storage into deep saline formations can also be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry. Potential deleterious impacts such as fatigue and corrosion are most likely to be caused by mixed gas streams such as $CO_2$ and $H_2S$. The presence of acidic gases can lead to the reduction in pH of formation fluids causing dissolution of minerals. Although acification and dissolution might increase prorosity, secondary precipitation of minerals can also reduce porosity and permeability. Sudden pressure drops can lead to extreme freeze-up causing values to cease up. Standard reservoir mangement and contingency plans should avoid such complications. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of monoethylene glycol.

## Expert Review Comments

- The report provides a good reference source for existing projects such as Sleipner. It has useful references and gives excellent details of industrial process variability. It also provides notable insights and identifies gaps in knowledge and challenges.
- The origin of some data is unclear. The authors have had to comply real-world data without revealing either specific sources or companies because of commercially sensitive information. This is particularly evident when the well-known large-scale demonstration projects are compared to the widespread $CO_2$-EOR operations in the United States.
- Much of the anecdotal information is concentrated on experience in the United States especially pipeline operation and $CO_2$-EOR. This is because the vast majority of $CO_2$-EOR operations take place there.

- There may be limits to onshore $CO_2$-EOR operations that can be transferred offshore. The authors did summarise the lessons learned from offshore projects. Some of the experience of onshore $CO_2$ pipeline operation can be transferred offshore.
- None of the five named projects is an example of anthropogenic $CO_2$ and therefore these are not exemplars of variable flow used in a storage operation. There is a lack of real-world data directly linking an anthropogenic source to a sink. However, the report comments on trends that have been inferred from variable power generation.
- Experiences related to a depleted gas field do not apply to deep saline formations. This assertion was disputed by the authors who highlighted the broad spectrum of studies that support the relevance of and applicability of $CO_2$ storage into both types of reservoir.
- Updated information on the UK's proposed Yorkshire and Humber network has been included.
- More detail has been provided on how intermittency is treated during $CO_2$-EOR operations.

## Conclusions

- Approximately 28% of global $CO_2$ emissions come from coal-fired power plants. After scrubbing and dehydration relatively pure 99.7% $CO_2$ can be achieved. Investigations carried out by this study revealed that $CO_2$ concentrations in the flue gas were fairly constant across the load range varying from 10% to 12%.
- Capture technology can produce comparatively pure $CO_2$ from cement plants but they are often operate intermittently consequently their integration into a $CO_2$ supply network would be challenging.
- Petroleum refineries can individually produce substantial volumes of $CO_2$, but from several different processes. $CO_2$ purities of 95% to 99% are feasible. Two refineries, the Pernis refinery in Rotterdam and Valero's refinery in Port Arthur Texas, have $CO_2$ capture facilities from hydrogen production unit syngas streams that delivered $CO_2$ to pipeline networks.
- Impurities can have negative impacts on pipelines including fracture propagation, corrosion, non-metallic component deterioration and the formation of hydrates and clathrates. However, compression and transport of $CO_2$ for $CO_2$-EOR use in the United States has shown that impurities are not likely to cause transport problems provided $CO_2$ stream composition standards are maintained and pressures are kept significantly over the critical point (≥10.3 MPa).
- Impurities can have a significant effect on temperature and pressure conditions and also on the density and viscosity of fluids. Sudden temperature drops can cause embrittlement and/or hydrate formation both of which can damage pipelines. However, pressure control systems are designed and operated to ensure operating conditions avoid deleterious effects.
- The most significant effect on transport and injection of $CO_2$ is the water content. The formation of carbonic acid can corrode a pipeline at a rate of 1-2mm within 2 weeks. Hydrate formation can lead to the most dramatic interruption to flow but the condition is generally preventable using multistage compression and knock out systems plus the inclusion of monoethylene glycol.
- Sudden pressure drops can also lead to extreme freeze-up causing values to cease up. Standard reservoir mangement and contingency plans should avoid such complications.
- Maintaining sufficient pressure is possible onshore with compressor plants but this option is not possible offshore. Lengthy offshore pipelines may need to be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained.
- $CO_2$-EOR relies on controlling pressure and flow rate conditions to optimise oil recovery. Restricted injection caused by wells being shut in can result in deleterious changes in reservoir pressure and oil miscibility. Under these conditions attendant drops in oil production could occur and in some circumstances the precipitation of minerals or asphaltenes or changes in formation fluid saturation properties could occur. Reservoir permeability can be reduced as a result. This investigation found that experienced operators can plan for intermittency and use strategies such as water injection and pipeline packing to manage impacts.
- Intermittent flow can have an impact on wellbore integrity, fatigue and corrosion. Changes in gas pressure can result in deleterious phase behaviour including segregation of the component gases leading to corrosive effects.

- $CO_2$ storage into deep saline formations can be managed by using multiple wells and water pumping to control and releave excess pressure, and control plume geometry.

## Knowledge Gaps

The following gaps in knowledge and proposed topics for future research and development were identified by this study. The topics are arranged in order of priority.

- Experimental research is needed to validate model predictions, particularly the behaviour of $CO_2$ containing impurities during transport. More experience is required to understand the nature of the $CO_2$ flow, the range of slug speeds and induced stresses on pipelines.
- A better understanding of the fundamental properties of $CO_2$ mixtures with impurities and their impact on operation and costs is required for pipeline transport, injection and storage.
- Improve the accuracy of predicted thermodynamic and transport properties over a range of compositions and conditions of fluid transported in pipelines.
- There is a need for a recommended practice or guideline on transmission of supercritical $CO_2$ that incorporates all of the industry guidelines and standards. The aim of this initiative is to ensure that all pipelines will meet safety standards.
- Models need to be accurate over a wide range of $CO_2$ compositions pertinent to CCS. Equally accurate experimental data will be necessary to validate property models.
- The response of intermittent flow to different types of reservoir needs to be understood.
- There is a need for an improved understanding of heat-transfer characteristics of $CO_2$ pipelines in different media such as sea water, gravel, clay and when ice-covered.
- There is a need for accurate prediction of:
    - Multiphase properties as well as of solid $CO_2$ and hydrate formation.
    - Improved modelling of captured $CO_2$ fluid wave-propagation, flow-regime and component-tracking between phases.
    - Noise generation and atmospheric dispersion prediction.
    - Metal crack propagation behaviour.
- Experimental validation of custom and commercial software-based depressurization models (such as OLGA) would enable their application to real-world scenarios with confidence.
- Publically accessible accurate capital and operating cost information especially for $CO_2$ from variable anthropogenic sources.

## Recommendations

- IEAGHG could consider undertaking study of the fundamental properties of $CO_2$ mixtures with impurities and their impact on operation particularly costs for pipeline transport, injection and storage, if no other study or reference sources exists.
- IEAGHG could consider co-ordinating a workshop, to define the experimental research and model validation that is needed to predict the behaviour of $CO_2$ containing variable concentrations of impurities during transport.
- IEAGHG could consider a future study to review to collate operational experience of $CO_2$ flow in pipelines over a range of slug speeds and induced stresses.

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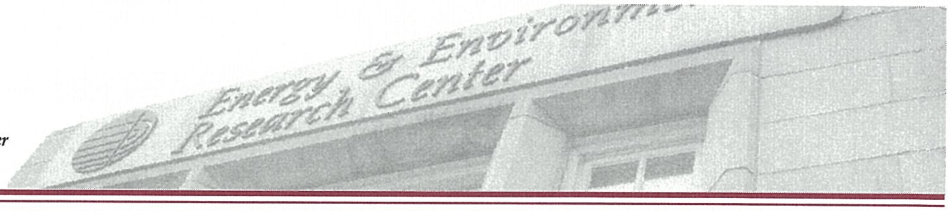


# OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE (IEA/CON/13/218)

Final Report

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# OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE


## ABSTRACT

Carbon dioxide ($CO_2$) is produced in large quantities during electricity generation and by industrial processes. These $CO_2$ streams vary in terms of both composition and mass flow rate, sometimes substantially. The impact of a varying $CO_2$ stream on pipeline and storage operation is not fully understood in terms of either operability or infrastructure robustness. This study was performed to summarize basic background from the literature on the topic of operational flexibility of $CO_2$ transport and storage, but the primary focus was on compiling real-world lessons learned about flexible operation of $CO_2$ pipelines and storage from both large-scale field demonstrations and commercial operating experience. Modeling and pilot-scale results of research in this area were included to illustrate some of the questions that exist relative to operation of carbon capture and storage (CCS) projects with variable $CO_2$ streams. It is hoped that this report's real-world findings provide readers with useful information on the topic of transport and storage of variable $CO_2$ streams.

The real-world results were obtained from two sources. The first source consisted of five full-scale, commercial transport–storage projects: Sleipner, Snøhvit, In Salah, Weyburn, and Illinois Basin–Decatur. These scenarios were reviewed to determine the information that is available about $CO_2$ stream variability/intermittency on these demonstration-scale projects. The five projects all experienced mass flow variability or an interruption in flow. In each case, pipeline and/or injection engineers were able to accommodate any issues that arose. Significant variability in composition has not been an issue at these five sites. The second source of real-world results was telephone interviews conducted with experts in $CO_2$ pipeline transport, injection, and storage during which commercial anecdotal information was acquired to augment that found during the literature search of the five full-scale projects. The experts represented a range of disciplines and hailed from North America and Europe.

Major findings of the study are that compression and transport of $CO_2$ for enhanced oil recovery (EOR) purposes in the United States has shown that impurities are not likely to cause transport problems if $CO_2$ stream composition standards are maintained and pressures are kept at 10.3 MPa or higher. Cyclic, or otherwise intermittent, $CO_2$ supplies historically have not impacted in-field distribution pipeline networks, wellbore integrity, or reservoir conditions. The U.S. EOR industry has demonstrated that it is possible to adapt to variability and intermittency in $CO_2$ supply through flexible operation of the pipeline and geologic storage facility. This $CO_2$ transport and injection experience represents knowledge that can be applied in future CCS projects. A number of gaps in knowledge were identified that may benefit from future research and development, further enhancing the possibility for widespread application of CCS.



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## NOMENCLATURE

| | |
|---|---|
| °C | degrees Celsius |
| °F | degree Fahrenheit |
| API | American Petroleum Institute |
| Ar | argon |
| As | arsenic |
| atm | atmosphere |
| bbl | barrel |
| Bcfd | billion cubic feet per day |
| CCS | carbon capture and storage |
| CCTS | capture, compression, transport, and storage |
| Cd | cadmium |
| $CH_4$ | methane |
| CO | carbon monoxide |
| Co | cobalt |
| COS | carbonyl sulfide |
| $CO_2$ | carbon dioxide |
| cm | centimeters |
| Cr | chromium |
| Cu | copper |
| D | Darcy |
| DGC | Dakota Gasification Company |
| EOR | enhanced oil recovery |
| FCCU | fluidized catalytic cracking unit |
| gal | gallons |
| Gtonnes | gigatonnes, or billion metric tons |
| GWh | gigawatt hour, or billion watt hours |
| $H_2$ | hydrogen |
| $H_2O$ | water |
| $H_2S$ | hydrogen sulfide |
| HCl | hydrogen chloride |
| HCU | hydrocracking unit |
| HF | hydrogen fluoride |
| Hg | mercury |
| $Hg^{2+}$ | mercuric ion |
| hr | hours |
| HSE | Health, Safety, and the Environment |
| HSU | hydroskimming unit |
| IDLH | immediately dangerous to life and health |
| IEAGHG | IEA Greenhouse Gas R&D Programme |
| in. | inches |
| InSAR | Interferometric synthetic aperture radar |
| kg | kilogram |
| km | kilometers |

| | |
|---|---|
| $kscm^3$ | thousand standard cubic meters |
| ktonnes | thousand metric tons |
| LNG | liquefied natural gas |
| m | meter |
| MAOP | maximum allowable operating pressure |
| mD | millidarcies |
| MDEA | methyldiethanolamine |
| MEG | monoethylene glycol |
| mg | milligram |
| mi | miles |
| min | minutes |
| $Mm^3$ | million cubic meters |
| MMcf | million cubic feet |
| MMcfd | million cubic feet per day |
| MMP | minimum miscibility pressure |
| Mn | manganese |
| mol% | mole percent |
| MPaA | megapascals absolute |
| MPaG | megapascals gauge |
| $MSm^3$ | mega standard cubic meters/day |
| Mtonnes | megatonnes, or million metric tons |
| MW | megawatt, or million watts |
| MWh | megawatt hour, or million watt hours |
| $N_2$ | nitrogen |
| $NH_3$ | ammonia |
| Ni | nickel |
| $NO_2$ | nitrogen dioxide |
| $NO_x$ | nitrogen oxides |
| $O_2$ | oxygen |
| Pb | lead |
| PC | pulverized coal |
| ppm | parts per million |
| psig | pounds per square inch gauge |
| RTO | regional transmission organization |
| Sb | antimony |
| Se | selenium |
| SLB | Sleipner B wellhead platform |
| SLT | Sleipner west treatment platform |
| Sn | tin |
| $SO_2$ | sulfur dioxide |
| $SO_3$ | sulfur trioxide |
| $SO_x$ | sulfur oxides |
| std | standard [conditions] |
| Te | tellurium |
| TEQ | toxicity equivalence |
| Tl | thallium |

| | |
|---|---|
| tonne | metric ton |
| TWh | terawatt hours, or trillion watt hours |
| USD | US dollars |
| V | vanadium |
| VBU | visbreaking unit |
| VOC | volatile organic compounds |
| vol% | volume percent |
| WAG | water alternating gas |
| yr | year |
| Zn | zinc |

# OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE

## EXECUTIVE SUMMARY

Carbon dioxide ($CO_2$) is produced in large quantities during electricity generation and by industrial processes. These $CO_2$ streams vary in terms of both composition and mass flow rate, sometimes substantially. The impact of a varying $CO_2$ stream on pipeline and storage operation is not fully understood in terms of either operability or infrastructure robustness. This study was performed by the Energy & Environmental Research Center (EERC) to summarize basic background from the literature on the topic of operational flexibility of $CO_2$ transport and storage, but the primary focus was on compiling real-world lessons learned about flexible operation of $CO_2$ pipelines and storage from both large-scale field demonstrations and commercial operating experience. Modeling and pilot-scale results of research in this area were included to illustrate some of the questions that exist relative to operation of carbon capture and storage (CCS) projects with variable $CO_2$ streams. To make the information as useful as possible, cost implications and knowledge gaps that exist relative to transport and storage of variable or intermittent $CO_2$ streams were identified. It is hoped that this report's real-world findings provide readers with useful information on the topic of transport and storage of variable $CO_2$ streams.

The real-world results were obtained from two sources. The first source consisted of five full-scale, commercial transport–storage projects: Sleipner, Snøhvit, In Salah, Weyburn, and Illinois Basin–Decatur. These scenarios were reviewed to determine the information that is available about $CO_2$ stream variability/intermittency on operations at these demonstration-scale projects. The five projects all experienced mass flow variability or an interruption in flow. In each case, pipeline and/or injection engineers were able to accommodate any issues that arose. Significant variability in composition has not been an issue at these five sites. The second source of real-world results was telephone interviews conducted with experts in $CO_2$ pipeline transport, injection, and storage during which commercial anecdotal information was acquired to augment that found during the literature search of the five full-scale projects. The experts represented a range of disciplines and hailed from North America and Europe.

Variability in mass flow rate can cause variations in temperature and pressure within a $CO_2$ pipeline. Changes in $CO_2$ composition will also affect how the $CO_2$ behaves in a pipeline. Modeling results have indicated that the presence of certain impurities may make it difficult to maintain single-phase flow. The presence of impurities changes the physical and transport properties of $CO_2$ as well as the $CO_2$ stream hydraulics. Impurities can change other aspects of the pipeline and lead to fracture propagation, corrosion, nonmetallic component deterioration, the formation of hydrates and clathrates, and even a change in the capacity of the pipeline itself. Impurities make it more difficult to model the conditions needed for safe depressurization and operation at transient conditions. The impurity with the most significant effect on transport and injection of $CO_2$ is water, which can form corrosive carbonic acid or hydrates that can clog the pipeline. Ensuring that a $CO_2$ stream meets an appropriate quality specification is crucial.

Modeling/simulation and risk assessments that were researched did not provide information about the specific effects of variable $CO_2$ streams on pipeline health, safety, and

environmental performance. Safe operation of $CO_2$ pipelines begins with a design that establishes source compositions and flow conditions with a safety margin. Most (if not all) $CO_2$ pipelines in North America are designed with larger diameters and thicker walls than necessary so as to make it possible to transport additional $CO_2$ should it become available in the future.

Temporary storage and $CO_2$ pipeline networks/hubs can be useful for controlling the flow in a pipeline or set of pipelines to minimize compositional and/or mass flow rate variations. Temporary storage can consist of fabricated or geologic storage or pipeline packing, which would likely offer limited storage. Networks can consist of a dedicated pipeline linking a single source to a single geologic sink or various combinations of multiple sources and multiple geologic sinks. Multiple sources can offer options for control of the flow in a pipeline system, especially when the sources are of various types. When some of the sources are not producing $CO_2$, it is likely that others will be although it will be important to ensure that not all sources on a shared pipeline vary their rate at the same time. Multiple sources can provide an averaging effect for the $CO_2$ stream composition, provided that they all meet a minimum quality standard.

Intermittent $CO_2$ flow to an injection site such as for enhanced oil recovery (EOR) could result in an inconsistency in $CO_2$ phase behavior within the in-field distribution pipeline system. If not properly managed, changes in reservoir pressure can result in geochemical reactions such as precipitation of minerals (and perhaps asphaltenes, paraffins, and calcite precipitation) or even change the fluid saturation properties of the rock. This could have long-term impacts on key reservoir characteristics such as injectivity and relative permeability. Prior knowledge of the reservoir characteristics and injectate composition can be applied using standard engineering principles to design and operate injection schemes that minimize the negative effects of $CO_2$ supply intermittency or changes in composition.

There has been concern regarding possible linkage between variability in $CO_2$ injection rate and induced seismicity. Unless variability produces excessive rates, pressures, volumes, or other conditions, the effect of $CO_2$ variability upon seismicity is too subtle to identify or predict.

Major findings of the study are that compression and transport of $CO_2$ for EOR purposes in the United States has shown that impurities are not likely to cause transport problems if $CO_2$ stream composition standards are maintained and pressures are kept at 10.3 MPa or higher. Cyclic, or otherwise intermittent, $CO_2$ supplies historically have not impacted in-field distribution pipeline networks, wellbore integrity, or reservoir conditions. The U.S. EOR industry has demonstrated that it is possible to adapt to variability and intermittency in $CO_2$ supply through flexible operation of the pipeline and geologic storage facility. This $CO_2$ transport and injection experience represents knowledge that can be applied in future CCS projects. A number of gaps in knowledge were identified that may benefit from future research and development, further enhancing the possibility for widespread application of CCS.

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# OPERATIONAL FLEXIBILITY OF $CO_2$ TRANSPORT AND STORAGE

## 1.0 INTRODUCTION

Carbon dioxide ($CO_2$) is produced in large quantities during electricity generation and by industrial processes. These $CO_2$ streams vary in terms of both composition and mass flow rate, sometimes substantially. The impact of a varying $CO_2$ stream on pipeline and storage operation is not fully understood in terms of either operability or infrastructure robustness. This study was performed by the Energy & Environmental Research Center (EERC), with support from the U.S. Department of Energy (DOE) and the IEA Greenhouse Gas R&D Programme (IEAGHG), to summarize basic background from the literature on the topic of operational flexibility of $CO_2$ transport and storage, but the primary focus was on compiling real-world lessons learned about flexible operation of $CO_2$ pipelines and storage from both large-scale field demonstrations and commercial operating experience. Modeling and pilot-scale results of research in this area were included to illustrate some of the questions that exist relative to operation of carbon capture and storage (CCS) projects with variable $CO_2$ streams. To increase the usefulness of the information, cost implications and knowledge gaps that exist relative to transport and storage of variable or intermittent $CO_2$ streams were identified.

The real-world results were obtained from two sources. The first source consisted of five full-scale, commercial transport–storage projects: Sleipner, Snøhvit, In Salah, Weyburn, and Illinois Basin–Decatur. These scenarios were reviewed to determine the information that is available about $CO_2$ stream variability/intermittency on operations at these demonstration-scale projects. The five projects all experienced mass flow variability or an interruption in flow. In each case, pipeline and/or injection engineers were able to accommodate any issues that arose. Significant variability in composition has not been an issue at these five sites. The second source of real-world results was telephone interviews conducted with experts in $CO_2$ pipeline transport, injection, and storage during which commercial anecdotal information was acquired to augment that found during the literature search of the five full-scale projects. The experts represented a range of disciplines and hailed from North America and Europe. The information acquired during the telephone interviews was considered to be business-sensitive and was provided for this study with the understanding that it would not be cited to a specific company or individual. The majority of the information comes from experience with North American onshore pipelines. This is because most operational $CO_2$ pipelines are located in North America, and they are the basis for a wealth of real-world experience. The experts who were contacted are summarized in Appendix A.

It is important to note that, while there are differences in the construction of onshore and offshore pipelines, the actual movement of a $CO_2$ stream through any pipeline is the same. Proof of this is that the same equations are used to size and design both onshore and offshore pipelines (IEA Greenhouse Gas R&D Programme, 2009). This study examined both onshore and offshore large-scale $CO_2$ injection projects and sought out experts with commercial experience. With respect to onshore projects, a majority of the expertise lies in the North American $CO_2$ enhanced oil recovery (EOR) industry. That experience includes over four decades of injection operations into over 13,000 wells from a variety of natural and anthropogenic sources (Meyer, 2007), many of which have successfully dealt with various levels of intermittency in their $CO_2$ supplies. In the case of offshore projects, there is significantly less experience, not only in terms of the number and duration of projects but also with respect to intermittency. However, the offshore projects at Sleipner and Snohvit did experience limited and periodic intermittency. While there are some uncertainties with respect to offshore $CO_2$ injection operations, particularly corrosion effects from impurities in the $CO_2$ stream and pipeline materials, those uncertainties can be addressed by applying conservative design elements to existing technology (Apeland and others, 2011). Therefore, the lessons learned with onshore pipelines can be applied to offshore pipelines as well.

Information from both the literature survey and the telephone interviews was synthesized and condensed to form this overview document, which summarizes important pertinent information for interested stakeholders such as project developers and other decision makers. It is hoped that this report's real-world findings provide readers with useful information on the topic of transport and storage of variable $CO_2$ streams.

## 2.0 REVIEW OF REAL-WORLD FLEXIBILITY IN $CO_2$ PIPELINE AND STORAGE OPERATION DURING REPRESENTATIVE FULL-SCALE TRANSPORT–STORAGE SCENARIOS

Five full-scale, commercial transport–storage scenarios were reviewed to determine the extent of real-world information that is publicly available about the effects of $CO_2$ stream variability/intermittency on operations at current CCS projects. These five projects, which are summarized in Table 1, were chosen because they reflect a broad range of CCS operations, in terms of both $CO_2$ source and geologic storage formation type. Furthermore, they are at commercial rather than pilot scale and have been in existence for long enough for data that relate to the effect of $CO_2$ stream variability on pipeline and injection operability to have been collected and analyzed. $CO_2$ source types that are represented are natural gas-processing facilities, a coal gasification facility, and an ethanol plant. Missing from this list are $CO_2$ sources that are likely to be targeted for capture because they are significant emitters: power plants and industrial processes such as steel and cement manufacture. Until the implementation of $CO_2$ capture at the Boundary Dam power station in Saskatchewan, Canada, there were no full-scale commercial transport–storage scenarios that involved $CO_2$ from a power generation station. That project began transporting and injecting $CO_2$ in October 2014, after this report was prepared. Similarly, there have been no data published from commercial-scale transport–storage scenarios in which steel or cement plants were the source of $CO_2$. (The Norcem Brevik cement works in Norway will not begin full-scale operation with carbon capture until 2015 [Talbot, 2014].) Geologic storage formations represented include deep saline reservoirs, a depleted natural gas reservoir, and an oil field for EOR. Each of the five projects that were reviewed is described in the following text, including available information about $CO_2$ stream variability and its effects on pipeline transport and/or operation of the geologic storage site.

**Table 1. Summary of Commercial Transport–Storage Scenarios That Were Reviewed**

| Project Name | $CO_2$ Source | Geologic Sink Type | Pipeline Length, km (mi)/Type |
|---|---|---|---|
| Sleipner | Gas-processing facility | Deep saline reservoir of the Utsira Formation | 12.5 (7.8)/offshore |
| In Salah | Gas-processing facility | Depleted portion of the Kretchba sandstone gas field | 14 (9)/onshore |
| Snøhvit | Liquid natural gas processing | Deep saline reservoir of the Tubåen and Stø sandstone formations | 153 (95)/offshore |
| Weyburn | Coal gasification | EOR | 330 (205)/onshore |
| Decatur (aka Illinois Industrial Carbon Capture and Storage Project) | Ethanol production | Saline reservoir in the Mt. Simon sandstone | 2 (1.2)/onshore |

### 2.1 Sleipner

The Sleipner project, operated by Statoil, is a sequestration project in which $CO_2$ removed from natural gas is injected into the deep saline reservoir of the Utsira Formation below the Norwegian North Sea (Figure 1). Sleipner claims the distinction of being the first carbon storage demonstration project in a deep saline reservoir, and it is the only demonstration in which the $CO_2$ is both captured and injected offshore (Global CCS Institute, 2014a). $CO_2$ has been commercially injected there for nearly two decades. At approximately US$50/tonne, the Norwegian Carbon Tax is the primary economic driver of commercial viability at Sleipner. Injection of approximately 1 million tonnes a year saves Statoil US$50 million annually (less project operating expenses) (Hosa and others, 2010).

Table 2 presents a summary of the characteristics of the Sleipner injection. The $CO_2$ is separated from natural gas using an amine scrubbing process so the stream leaving the capture system is supersaturated with water and has a pH of 3.0. It is composed of about 98% $CO_2$ and 2% methane (Global CCS Institute, 2014a). The stream contains up to 150 ppm $H_2S$ and no dissolved oxygen (Baklid and others, 1996). The $CO_2$ injected at Sleipner travels 12.5 km from the Sleipner West treatment platform (SLT) to the wellhead platform (SLB), then vertically down to the sea floor and another 1012 m to the unconsolidated sandstone of the lower Utsira Formation. Injection takes place through a 36-m perforation in the horizontal leg of a single injection well (Hagen, 2012).

$CO_2$ injection at Sleipner has been largely free of the supply and logistics interruptions that are characteristic of many carbon injection projects. The only considerable pauses in injection are planned 4-week workover periods that occur once every 2 years (Eiken and others, 2011). These workovers are planned well in advance and are coordinated to reduce unfavorable impacts on infrastructure and reservoir geology.


Figure 1. Map showing the location of the Sleipner geologic storage project (taken from Schlumberger, 2014a).

Shut-in periods pose challenges that could adversely affect injection at a site but planning prior to injection operations has greatly mitigated these challenges at Sleipner. For example, because Sleipner injection takes place below the cold North Sea, prolonged shut-ins can allow cooling at the top of the well (near the ocean floor). This cooling can cause the temperature and pressure to drop to 5°C and 4.0 MPa, respectively, conditions that are directly along the $CO_2$ saturation line (shown in Figure 2) and squarely within the envelope for hydrate formation if the injectate contains water. The actual risk of hydrate formation is minimal, however, because of appropriate design choices. The risk of injectivity loss is even more remote because of the favorable geology of the reservoir.

The $CO_2$ is compressed in four stages to 8.0 MPa and cooled to 40°C for injection at the wellhead in the supercritical state. During each compression stage, water is removed from the stream at 30°C. The ability of $CO_2$ to dissolve water at 3.2 MPa (the pressure after the third stage) is lower than it is at the wellhead, so there is no free water available at the wellhead and corrosion and hydrate formation are limited during the injection operation. It should also be noted that, because the final water knockout takes place at 3.2 MPa, the injectate stream maintains all water in solution even when a shut-in causes the pressure to drop to 4.0 MPa (Torp and Brown, 2005). Another way that hydrate formation is inhibited is through the addition of low-dose monoethylene glycol (MEG) that is added prior to each biennial workover.

**Table 2. Summary of Sleipner Injection Project Characteristics**

| | | Reference |
|---|---|---|
| Capture | | |
| Location | Sleipner T platform | Johannessen, 2012 |
| Capture Technology | Amine scrubbing using 45% MDEA[a] | Hagen, 2012 |
| $CO_2$ Stream Composition | ~98% $CO_2$, ~ 2% $CH_4$, 150 ppm $H_2S$ | Hagen, 2012; R&D Project $CO_2$ Value Chain, 2009; Baklid and others, 1996 |
| Temperature | 60°–80°C | Hagen, 2012 |
| Pressure | 10.0 MPa | Johannessen, 2012 |
| Number of Compressor Trains | 1 | IEA Greenhouse Gas R&D Programme, 2008 |
| Pipeline | | |
| Length | 12.5 km | Serpa and others, 2011 |
| Pressure | 8.0 MPa at 40°C | IEA Greenhouse Gas R&D Programme, 2008 |
| Phase | In the pipeline: supercritical; At the wellhead: two-phase flow | IEA Greenhouse Gas R&D Programme, 2008; Munkejord and others, 2013 |
| Capacity | 1.1–1.2 Mtonnes/yr | Zero Emission Resource Organisation, 2013b |
| Transport Rate | About 900 ktonne/yr | Johannessen, 2012 |
| Environment | Seabed | True, 2012 |
| Storage | | |
| Location | Sleipner B platform | Hosa and others, 2010 |
| Formation | Utsira (Miocene) | Zero Emission Resource Organisation, 2013b |
| Reservoir Lithology | Unconsolidated sandstone | Hosa and others, 2010 |
| Porosity | 35%–40% | Baklid and others, 1996 |
| Permeability | 1–8 D | Baklid and others, 1996 |
| Thickness | 150–250 m | Baklid and others, 1996 |
| Pressure | 8.0–10.0 MPa | Baklid and others, 1996 |
| Temperature | 37°C | Baklid and others, 1996 |
| Number of Injection Wells | 1 | IEA Greenhouse Gas R&D Programme, 2008 |
| Injection Rate | 2800 tonnes/day | Johannessen, 2012 |
| Injection Depth | 1012 m | Hosa and others, 2010 |
| Capital Cost | | |
| Entire Project | US$100 million | Zero Emission Resource Organisation, 2013b |

[a] Methyldiethanolamine.

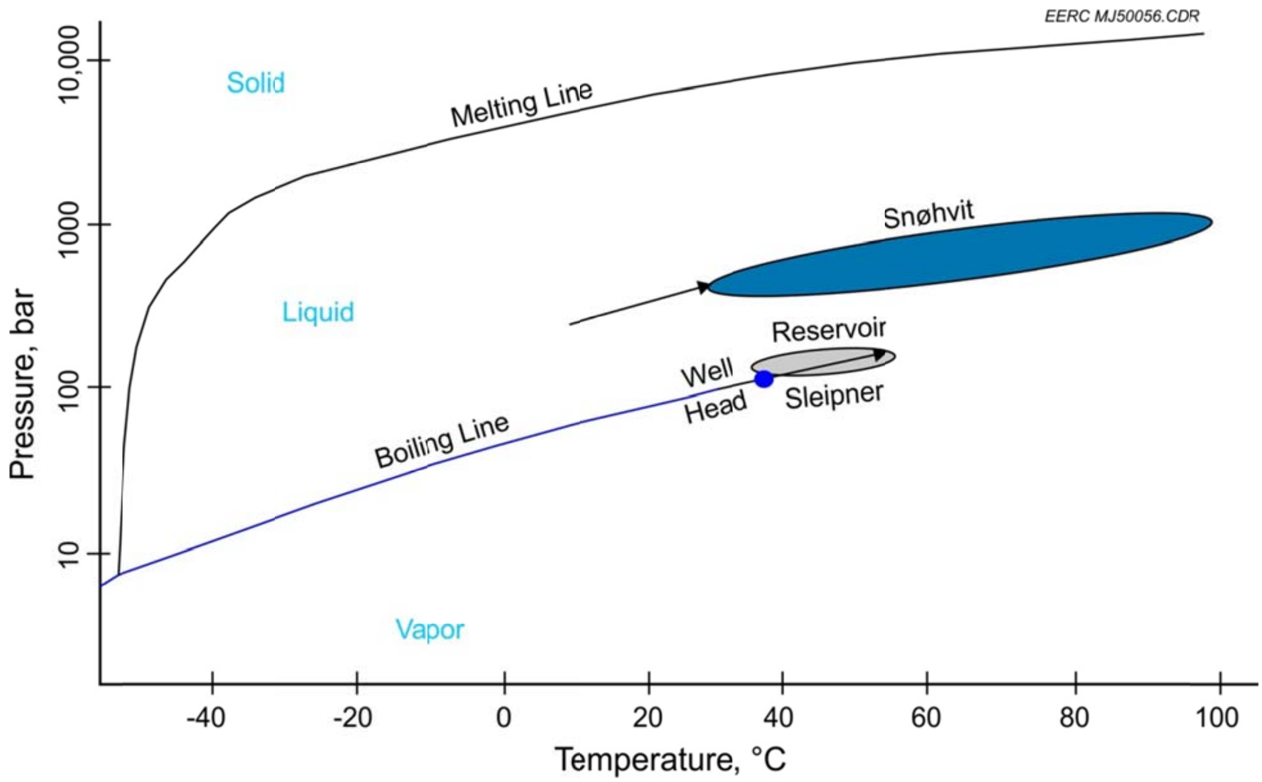


Figure 2. Phase behavior of $CO_2$ with the arrows representing wellhead and bottomhole conditions at Sleipner and Snohvit and the reservoir conditions denoted by the shaded envelopes (taken from Hagen, 2012).

The injection system was designed to be able to dispose of up to 1.7 $MSm^3$ $CO_2$/day, produced at any time. The amount varied as the production rate changed, depending on the pipeline offtake of gas as well as because of the differences in $CO_2$ content in the various segments of the Sleipner West hydrocarbon reservoir. A service life of 25 yr was required; i.e., the system was designed to inject against increasing pressure resistance that resulted from charging the formation with $CO_2$.

Materials selected for the $CO_2$-containing equipment were designed to resist both corrosion at injection conditions and sulfide stress cracking (Baklid and others, 1996). Corrosion resistance was incorporated by fabricating the injection well using 25% chromium duplex (stainless) steel downhole and 22% chromium duplex steel at the surface as this material could tolerate the composition of the $CO_2$ stream (Perkins, 2005; Wright and others, 2009). These design factors, when combined with the very forgiving porosity and permeability of the Utsira Formation, allow for uneventful shut-ins and very little change in injectivity when operations resume.

The favorable conditions and thoughtful design of the Sleipner project have generally allowed for avoidance of unplanned pauses in injection. The planned biennial pauses seem to have little adverse effect on injection operations.

## 2.2 Snøhvit

With over a decade of successful injection at Sleipner, Statoil and several other minority partners initiated another project, called Snøhvit, in which $CO_2$ from a natural gas stream is injected into a deep saline formation. Figure 3 shows the location of the Snøhvit project, while Table 3 summarizes important information about it. Injection at Snøhvit began in 2008. Natural gas from the Snøhvit, Albatross, and Askeladden gas fields is transported 143 km in a 68-cm-diameter multiphase pipeline to a liquified natural gas (LNG) plant located at Melkoya, near Hammerfest, Norway (Global CCS Institute, 2014b). The LNG-processing method requires the removal of $CO_2$ prior to liquefaction so that solid $CO_2$ will not form during the process (Global CCS Institute, 2014b). An amine process is used to separate the $CO_2$ from the natural gas.

The $CO_2$ product is transported 153 km to the project injection reservoir is the mid-Jurassic Tubåen sandstone, at a depth of 2600 m below the sea floor. Initial injection was via a single vertical well with three perforated zones between 2430 and 2600 m. Injection is performed at a rate of 700,000 tonnes/year. The LNG plant is expected to have a 30-year lifespan; therefore, about 23 million tonnes of $CO_2$ will be injected over the life of the project.

The Tubåen sandstone directly underlies the Stø Formation natural gas reservoir from which the Snøhvit, Albatross, and Askeladden gas fields produce their natural gas. Because of this proximity, particular attention was given to pressure monitoring and assessment of maximum safe injection pressure at the Snøhvit injection site.

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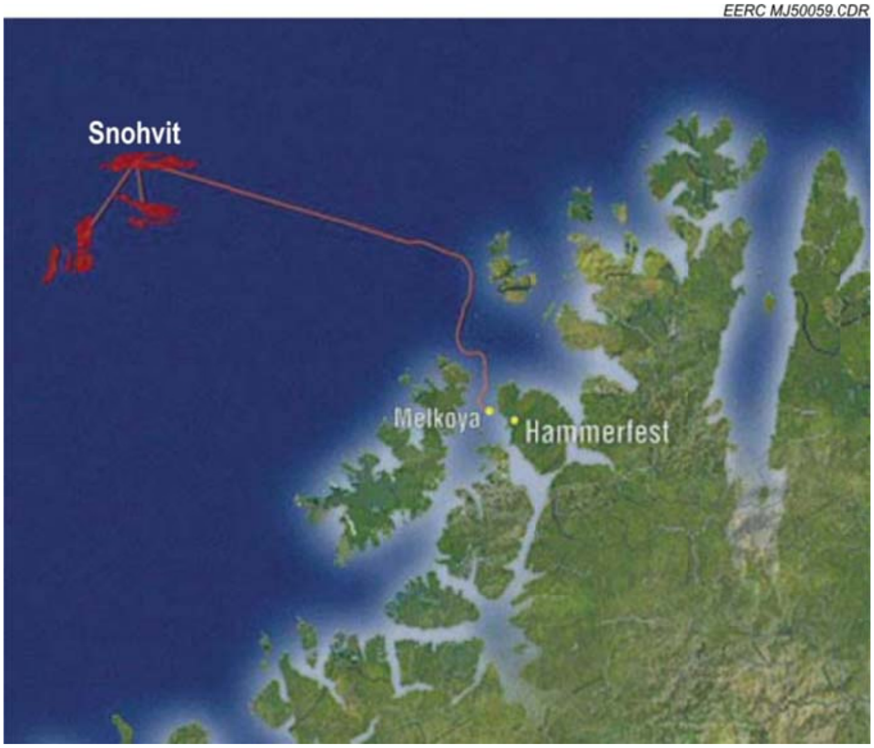


Figure 3. Location of the Snøhvit $CO_2$ injection site (taken from $CO_2$ Remove, 2014).

**Table 3. Summary of Snøhvit Injection Project Characteristics**

| | | Reference |
|---|---|---|
| Capture | | |
| Location | Hammerfest, Norway | Serpa and others, 2011 |
| Capture Technology | Amine scrubbing using MDEA[a] | Pettersen, 2011 |
| $CO_2$ Stream Composition | 99% | Global CCS Institute, 2014b |
| Temperature | 60°–80°C | Hagen, 2012 |
| Pressure | 10.0 MPa | Johannessen, 2012 |
| Number of Compressor Trains | 1 | IEA Greenhouse Gas R&D Programme, 2008 |
| Pipeline | | |
| Length | 153 km | Global CCS Institute, 2014b |
| Diameter | 210 mm | Global CCS Institute, 2014b |
| Phase | Liquid at wellhead | Serpa and others, 2011 |
| Transport Rate | 0.7 Mtonnes/yr maximum | hydrocarbons-technology.com, 2014 |
| Pipe Material | Steel with an outer coating of reinforced concrete | hydrocarbons-technology.com, 2014 |
| Environment | Seabed | Serpa and others, 2011 |
| MAOP[b] | 15.0 MPa | Mohitpour, 2012 |
| Storage | | |
| Location | Barents Sea, Norway | Global CCS Institute, 2014b |
| Formation | Tubåen (mid-Jurassic); changed to shallower Stø Formation[c] | Global CCS Institute, 2014b |
| Reservoir Lithology | Sandstone | Global CCS Institute, 2014b |
| Porosity | 13% | Chiaramonte and others, 2013 |
| Permeability | 130–880 mD | Chiaramonte and others, 2013 |
| Thickness | 100 m | Global CCS Institute, 2014b |
| Pressure | 11.3 MPa | Thu, 2013 |
| Temperature | 3.7°C | Thu, 2013 |
| Number of Injection Wells | 1 | Global CCS Institute, 2014b |
| Injection Rate | 1496 tonnes/day | Thu, 2013 |
| Injection Depth | 2560–2670 m | Global CCS Institute, 2014b |
| Capital Cost | | |
| Entire project | $5.3 billion | hydrocarbons-technology.com, 2014 |

[a] Methyldiethanolamine.
[b] Maximum allowable operating pressure.
[c] Increased well pressure indicated injection into a restricted compartment; the well was recompleted in the Stø Formation and operations continued.

There were logistical problems with the LNG gas-processing facility that supplied $CO_2$ to Snøhvit over the course of 2008, causing intermittent injection during that time. In 2009, when injection was more stable, operators began to see a buildup of pressure in the near-wellbore environment. This is shown in Figure 4. The pressure reached critical levels three different times in 2009, likely due to salt precipitation near the wellbore (Hermanrud and others, 2013). Injection in the North Sea requires dry $CO_2$ to prevent hydrate formation and corrosion. That same dry $CO_2$ can have some deleterious effects in specific geologic settings. At Snøhvit, the dry $CO_2$ was an excellent solvent for water in the near-wellbore brine. When the water was taken up in the injectate stream, the remaining salt precipitated and caused a rapid loss of injectivity (European CCS Demonstration Project Network, 2012). This issue was somewhat resolved through the use of MEG. Unfortunately, shortly thereafter another rise in pressure began, and in 2011, injection into the Tubåen Formation was stopped and the $CO_2$ was injected instead into the Stø Formation.

### 2.3 In Salah

The In Salah $CO_2$ project was a joint venture between Sonatrach, BP, and Statoil to store $CO_2$ in a Jurassic saline formation that also hosts current gas production fields in Algeria (Riddiford and others, 2005). Figure 5 shows the location of the In Salah $CO_2$ project. The reservoir was a depleted portion of the 1900-m deep Kretchba Formation, a carboniferous sandstone gas field. The project is summarized in Table 4.

The In Salah project was not an EOR project even though the >98%-pure $CO_2$ stream was injected into a depleted gas field. In EOR, the interaction of the $CO_2$ with the oil is what enhances the oil production. At In Salah, it was hoped that the $CO_2$ plume would not contact the hydrocarbon accumulations for at least 25–30 yr (Hosa and others, 2010).

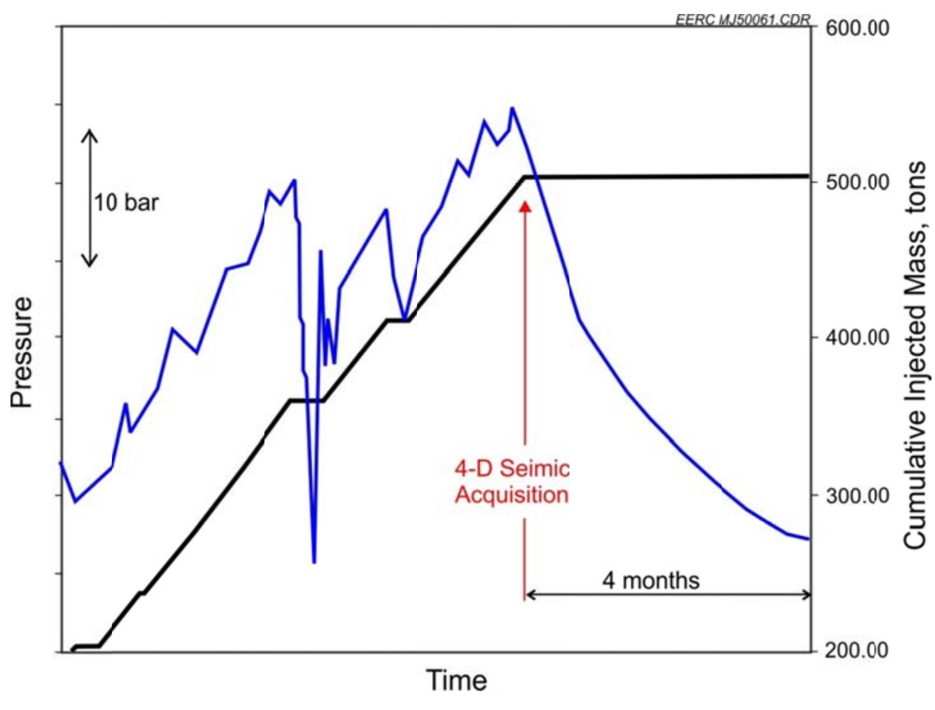


Figure 4. Snøhvit pressure and cumulative injected $CO_2$ during 2009 (taken from Eiken, 2010).

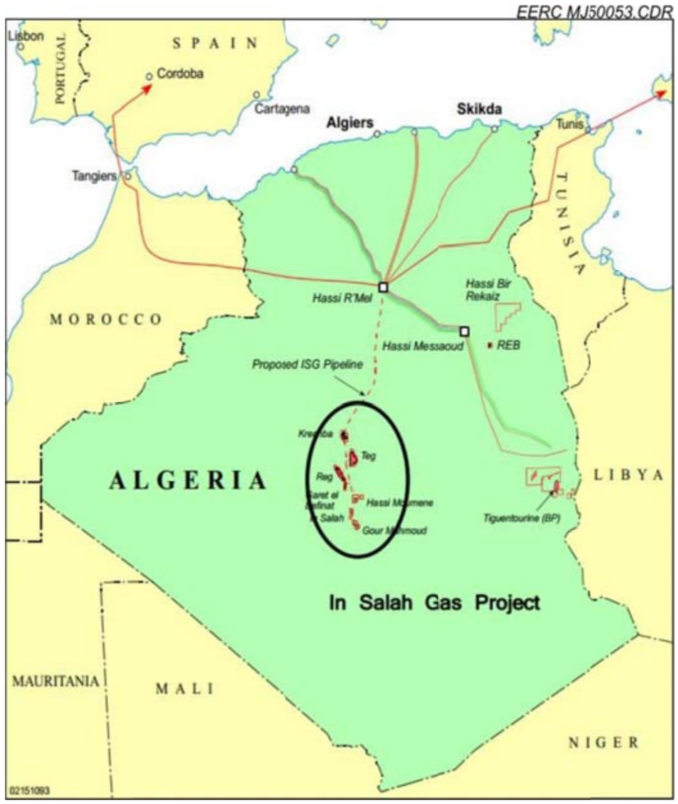


Figure 5. Location of the In Salah $CO_2$ project (taken from Wright, 2010).

The project was designed for an annual injection rate of 1.2-million tonnes using three horizontal wells but reportedly only 0.5 million/yr to 1 million tonnes/yr were injected while operating (Rutqvist and others, 2010). The Massachusetts Institute of Technology (MIT) fact sheet on the In Salah project notes that the total storage accomplished during the lifetime of the project was 3.8 million tons (Massachusetts Institute of Technology, 2014a).

Injection began to cause an unfavorable geomechanical response due in part to the site's low permeability. In 2007, operators began to suspect a leak at one of the three injection wells, KB-502. The leak was confirmed but was found to be very slow, on the order of a few cubic feet a day. The well was shut down for a period in June 2007, and a new flange was installed on the wellhead, which stopped the leak (Ringrose and others, 2009). Plans were tentatively made to resume injection in the well later that year, but because of the growing concerns about the geomechanical reaction, the well was not used for injection again until late 2009. This can be seen in Figure 6, which summarizes the monitoring observations at In Salah Injection Well KB-502.

As operations continued, new techniques were added to the monitoring suite to address growing concerns about the potential for induced seismicity. Specifically, interferometric synthetic aperture radar (InSAR) was used to monitor for any rise in ground level (shown in

**Table 4. Summary of In Salah Injection Project Characteristics**

| | | Reference |
|---|---|---|
| Capture | | |
| Location | Krechba, Algeria | Pham, 2012 |
| Capture Technology | BASF amine scrubbing process using activated MDEA[a] | In Salah Gas Stockage de $CO_2$, 2010 |
| $CO_2$ Stream Composition | >98% $CO_2$ | In Salah Gas Stockage de $CO_2$, 2010 |
| Pressure | 18.5 MPa after compression | In Salah Gas Stockage de $CO_2$, 2010 |
| Number of Compressor Trains | Two 4-stage centrifugal compression trains | In Salah Gas Stockage de $CO_2$, 2010 |
| Pipeline | | |
| Length | 14 km | In Salah Gas Stockage de $CO_2$, 2010 |
| Diameter | 406 mm | Theodora.com, 2008 |
| Phase | Supercritical | In Salah Gas Stockage de $CO_2$, 2010 |
| Transport Rate | 1.15 Mtonne/yr max | True, 2012 |
| Pipe material | Carbon steel | In Salah Gas Stockage de $CO_2$, 2010 |
| Environment | Desert | True, 2012 |
| Storage | | |
| Location | Krechba, Algeria | Massachusetts Institute of Technology, 2014a |
| Formation | Krechba Formation | Massachusetts Institute of Technology, 2014a |
| Reservoir Lithology | Fluvial (silts and sands) | Hosa and others, 2010 |
| Porosity | 17% | Hosa and others, 2010 |
| Permeability | 5 mD | Hosa and others, 2010 |
| Thickness | 29 m | Hosa and others, 2010 |
| Pressure | 18.5 MPaG | In Salah Gas Stockage de $CO_2$, 2010 |
| Temperature | | |
| Number of Injection Wells | 3 | In Salah Gas Stockage de $CO_2$, 2010 |
| Injection Rate | 1 Mtonnes/yr | Hosa and others, 2010 |
| Injection Depth | 1850 m | Hosa and others, 2010 |
| Capital Cost | | |
| Entire Project | US$1.7 billion | Zero Emission Resource Organisation, 2013a |

[a] Methyldiethanolamine.

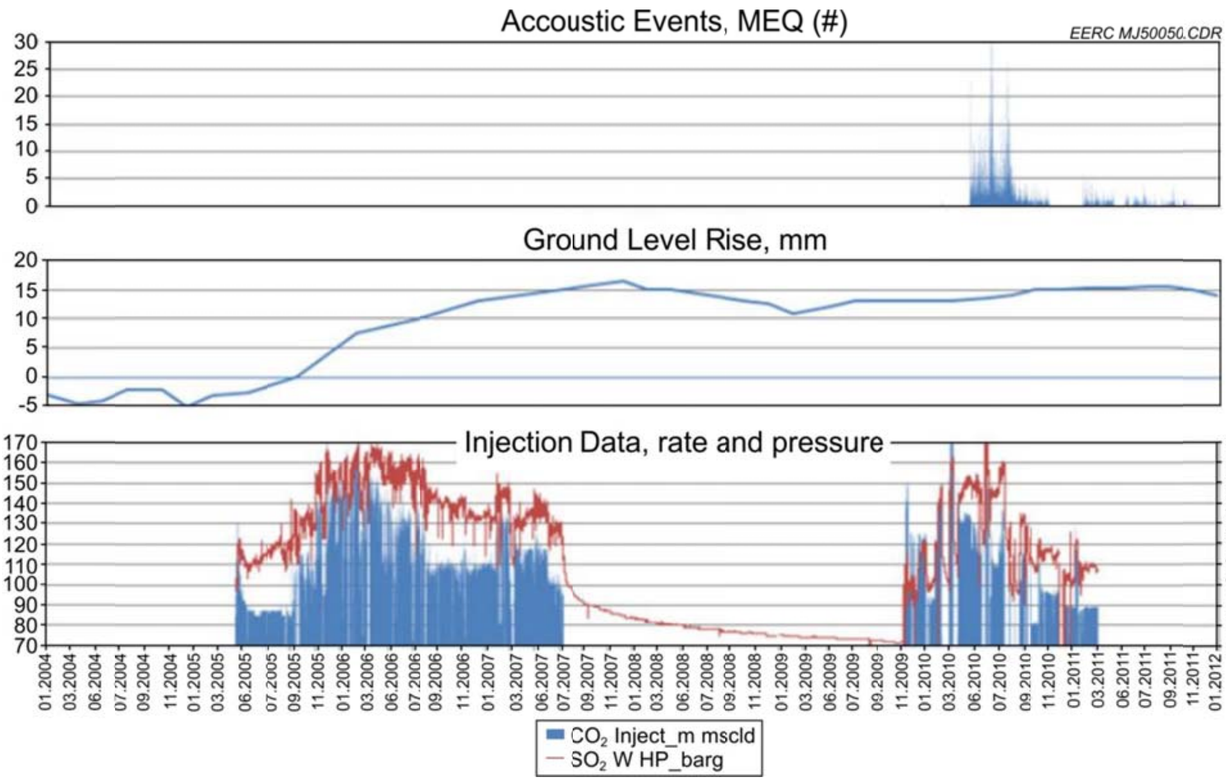


Figure 6. Summary of monitoring observations around Injection Well KB-502 (taken from Ringrose and others, 2013).

Figure 6) and seismic arrays were deployed to record microseismic events, as shown in Figure 7. A microseismic event is not the same as an earthquake. Microseismic events have a movement of 0.1 mm or less along a pathway of one to a few tens of meters in length. To put this in perspective, a conventional earthquake with a Richter magnitude of 3 or more would have a slip along the fault of about 1 cm along a fault patch that is a few hundred meters in length. In response to the ground level rise and an escalating number of microseismic events, injection was started and stopped repeatedly in both the KB-502 well and the injection pattern as a whole.

Geomechanical analysis suggested that the fracture pressure had been surpassed twice over the course of 2010 (Goertz-Allmann and others, 2013). In addition, InSAR measurements indicated faulting via measurement of a bilobed uplift pattern, which models suggested indicated the widening (by 50 mm) of an initially conductive, northwest-trending, 4-km-long fracture/fault (Durucan, 2011). When combined, these analyses generated further concern about possible vertical extension of existing fractures that could compromise the integrity of the primary seal. In response, injection was halted in 2011 to allow for further assessment of the geomechanical reaction. However, it is important to note that the In Salah monitoring program showed that the maximum extent of vertical fluid migration is less than 200 m above the top of the reservoir. A cap rock 950 m thick, consisting of multiple impermeable barriers, separates the $CO_2$ injection zone from the deepest drinking water resource. The upper 750 m of this seal are intact and unaffected by the microseismic events (White and others, 2014).

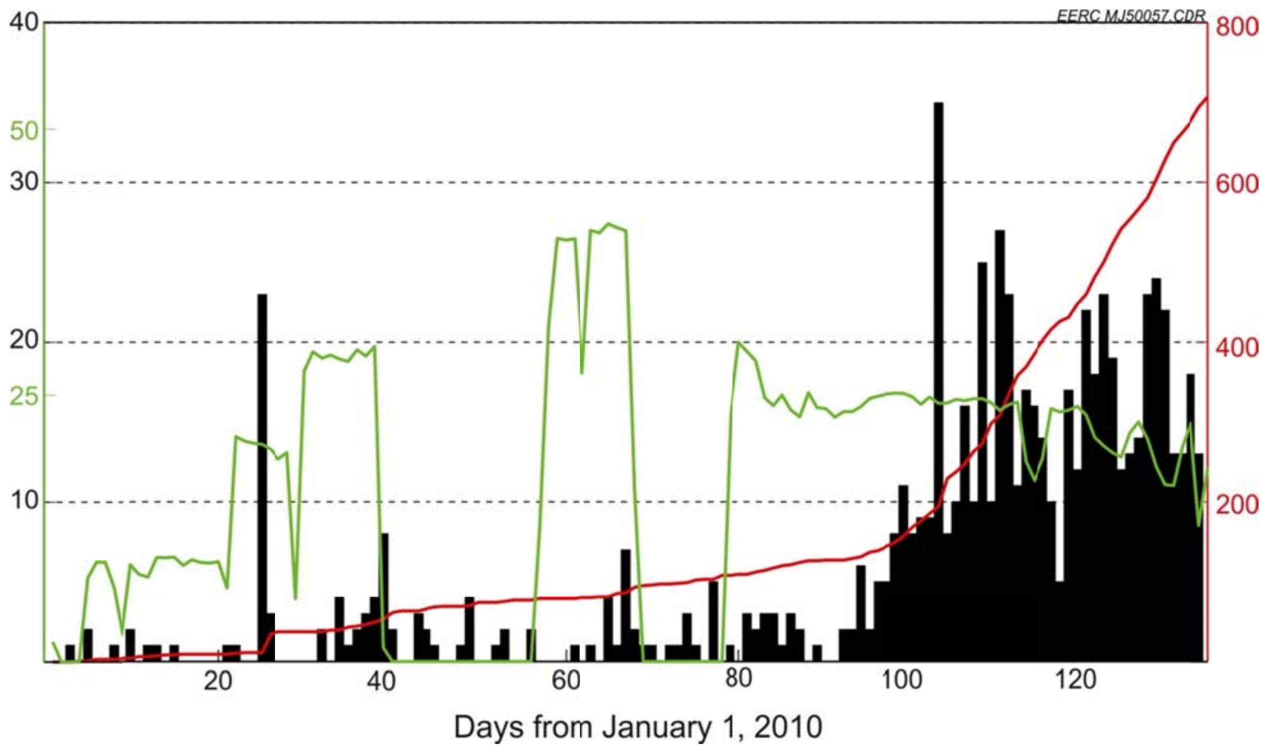


Figure 7. Microseismic events at the In Salah $CO_2$ project. The number of microseismic events per day is shown in black, the total number of events by a given date during the first 4 months of 2010 is shown in red, and the green line is the $CO_2$ injection rate in million standard cubic feet per day. Each line has its own scale, which is shown in the same color (taken from Verdan and others, 2013).

In terms of operational flexibility, Figures 6 and 7 indicate how frequently injection was interrupted. These interruptions often only affected an individual well but occasionally the injection was stopped completely. Without direct comparison, it is difficult to quantify the effect that these interruptions had on either injectivity or the related geomechanical stresses that were experienced.

There were no directly comparable projects with and without interrupted injection. The relationship between injected volumes and pressure changes within a single project over its operational lifetime were analyzed for potential operational impact caused by intermittent injection. Using the data that are represented in Figure 6, it can be seen that one might compare the volume/pressure relationship in the intervals between interruptions.

### 2.4 Weyburn

The Weyburn $CO_2$ project was initiated in 2000 by EnCana and the Petroleum Technology Research Center for the dual purpose of enhancing oil recovery using $CO_2$ and studying the EOR. The source of the $CO_2$ for the Weyburn project is the Dakota Gasification Company's (DGC's) Great Plains Synfuels Plant that produces synthetic natural gas from coal. This gives the project the distinction of being the first EOR project to use a manmade $CO_2$ stream that was not produced by a natural gas-processing plant. As part of the process to make synthetic natural gas, the Great Plains Synfuels Plant produces a $CO_2$ stream comprising 96.8% $CO_2$, 1.1% $H_2S$, 1.0% ethane, 0.3% methane, and 0.8% other gases (Eliason, 2004). About 8000 tonnes of $CO_2$ is transported 320 km via pipeline daily (Dakota Gasification Company, 2014). When it reaches the Weyburn Field in Saskatchewan, Canada, it is injected through 37 injection wells (Schlumberger, 2014b). The Weyburn project uses a nine-spot injection pattern in which each injection well is surrounded by eight production wells (Schlumberger, 2014b). Weyburn uses a water-alternating-gas (WAG) injection scheme with vertical wells injecting water and horizontal wells injecting $CO_2$ (Asghari and others, 2007). Details of the project are summarized in Table 5, while the location of the project is shown in Figure 8.

In 2004, $CO_2$ delivery from the Great Plains Synfuels Plant was interrupted for about 6 weeks while the plant was down for scheduled maintenance. Because the operators of the Weyburn project knew about the shutdown a year in advance, injection operations in the oil fields were able to continue by using recycled $CO_2$ and other reservoir pressure maintenance techniques (e.g., water injection, modifying the injection/production patterns, etc.).

A second planned interruption of $CO_2$ service to Weyburn in took place in 2013, when DGC conducted a scheduled shutdown for maintenance and retrofitting (Donovan, 2013). While data on the effects of these service interruptions are not available to the public, there are a few sources that can be consulted to confirm that they do have an effect. For example, Figure 9 shows the production of oil from Weyburn beginning during primary production and extending through 2010. Questions of infrastructure and injectivity cannot be directly addressed, but it appears that the effect that service interruptions have on oil production can be seen. The red ellipse on Figure 9 highlights a temporary decrease in oil production through late 2004. This decline reverses dramatically in 2005, which could be interpreted as a recovery from the effects of the service interruption. It cannot be claimed that this interruption did not negatively affect the Weyburn infrastructure or reservoir, but a case can be made that any effects there may have been were reversed in subsequent months. In the following years, production reached levels that had not been recorded since the height of primary production in the 1960s.

Another area of interest in terms of operational flexibility is whether WAG schemes have negative effects on the corrosion behavior of infrastructure. Because Weyburn operators chose not to directly integrate their water injection wells and $CO_2$ injection infrastructure, it is difficult to obtain insights on the interplay of water, $CO_2$, and service interruptions.

### 2.5 Illinois Basin–Decatur Project

The Midwest Geological Sequestration Consortium Illinois Basin–Decatur $CO_2$ injection project transports $CO_2$ from an Archer Daniels Midland (ADM) ethanol plant near Decatur, Illinois, into a deep saline formation via a 2-km pipeline (Hosa and others, 2010). The project is operated by ADM and the Illinois Geological Survey. Injection began in late 2011 with an initial rate of 1000 tonnes a day of injected $CO_2$. As of early 2014, 500,000 tonnes had been injected, halfway to the initial goal of 1 million tonnes by the end of 2014 (Massachusetts Institute of Technology, 2014b). The location of the project is shown in Figure 10, while pertinent data are summarized in Table 6.

**Table 5. Summary of Weyburn Injection Project Characteristics**

| | | Reference |
|---|---|---|
| Capture | | |
| Location | Great Plains Gasification Plant, Beulah, North Dakota, USA | Eliason, 2004 |
| Capture Technology | Rectisol® | Dakota Gasification Company, 2014 |
| $CO_2$ Stream Composition | 96.8% $CO_2$, 1.1% $H_2S$, 1.0% ethane, 0.3% methane, 0.8% other gases | Eliason, 2004 |
| Number of Compressors | 3 | IEA Greenhouse Gas R&D Programme, 2014 |
| Compressor Discharge Pressure | 18.6 MPaG (2700 psig) | Eliason, 2004 |
| Pipeline | | |
| Length | 320 km | Dakota Gasification Company, 2014 |
| Diameter | 356 mm (14 in.) and 305 mm (12 in.) | Eliason, 2004 |
| Delivery Pressure | 15.0 MPaG (2175 psig) | Perry and Eliason, 2004 |
| Phase | Supercritical | Perry and Eliason, 2004 |
| Capacity | 240 mmscf/d (= 4.6 Mtonnes/yr) | Dakota Gasification Company, 2013 |
| Transport Rate | 8000 tonnes/d | Dakota Gasification Company, 2014 |
| Pipe Material | Carbon steel | Eliason, 2004 |
| Environment | Arid farmland | North Dakota State University, 2014 |
| MAOP[a] | 18.6 MPaG (2700 psig) (14-in.); 20.4 MPaG (2964 psig) (12-in.) | Eliason, 2004 |
| Storage | | |
| Location | Southeast Saskatchewan, Canada | Petroleum Technology Research Centre, 2014 |
| Formation | Charles Formation (Mississippian) | Hosa and others, 2010 |
| Reservoir Lithology | Limestone/dolomite | Hosa and others, 2010 |
| Porosity | 8%–38% | Hosa and others, 2010 |
| Permeability | 1–300 mD | Hosa and others, 2010 |
| Thickness | 30 m | Hosa and others, 2010 |
| Number of Injection Wells | 37 | Schlumberger, 2014b |
| Injection Rate | 2.7 Mtonnes/yr | Hosa and others, 2010 |
| Injection Depth | 1418 m | Hosa and others, 2010 |
| Capital Cost | | |
| Entire Project | US$1.1 billion (pipeline cost was US$100 million) | Zero Emission Resource Organisation, 2014 |

[a] Maximum allowable operating pressure.

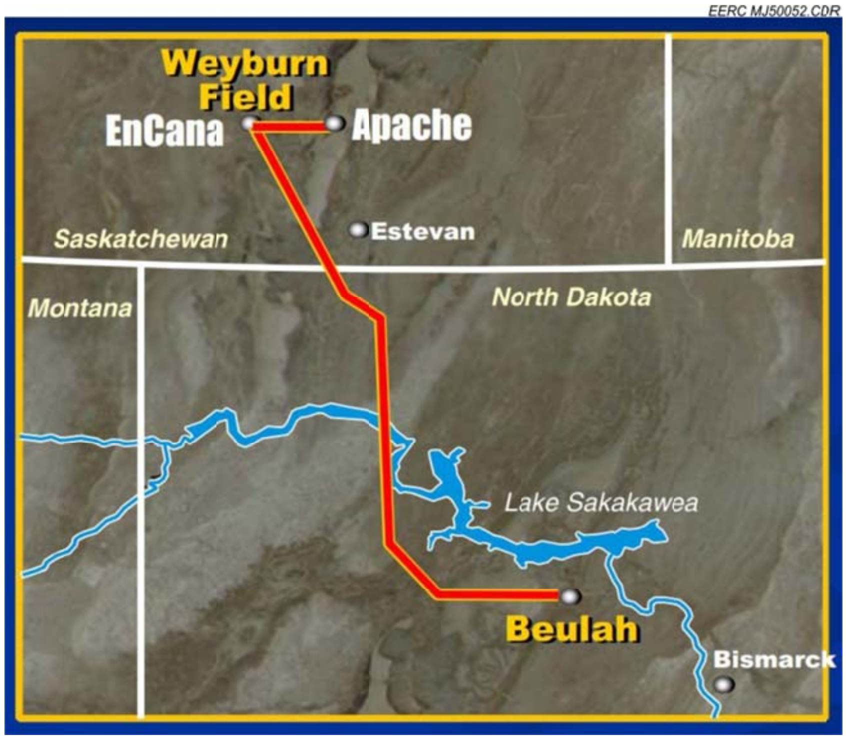


Figure 8. Location of the Weyburn $CO_2$ project (taken from Dakota Gasification Company, 2013).

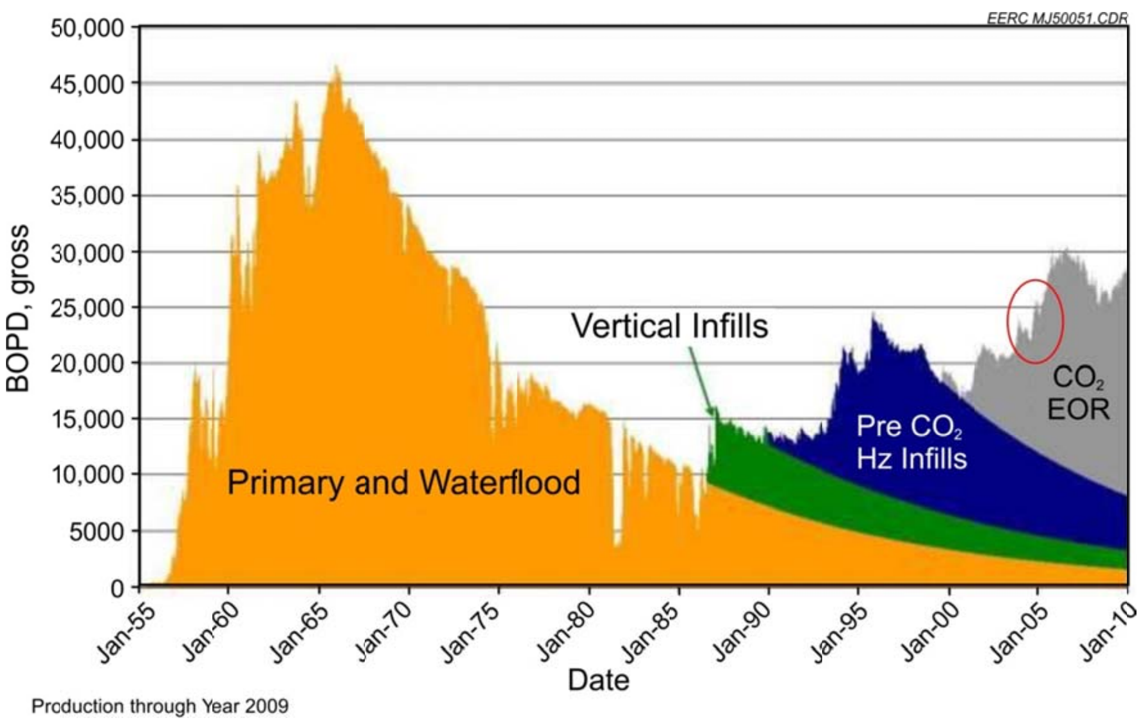


Figure 9. The effect of the various forms of EOR on the production of oil (from Munisteri and Kotenev, 2013).

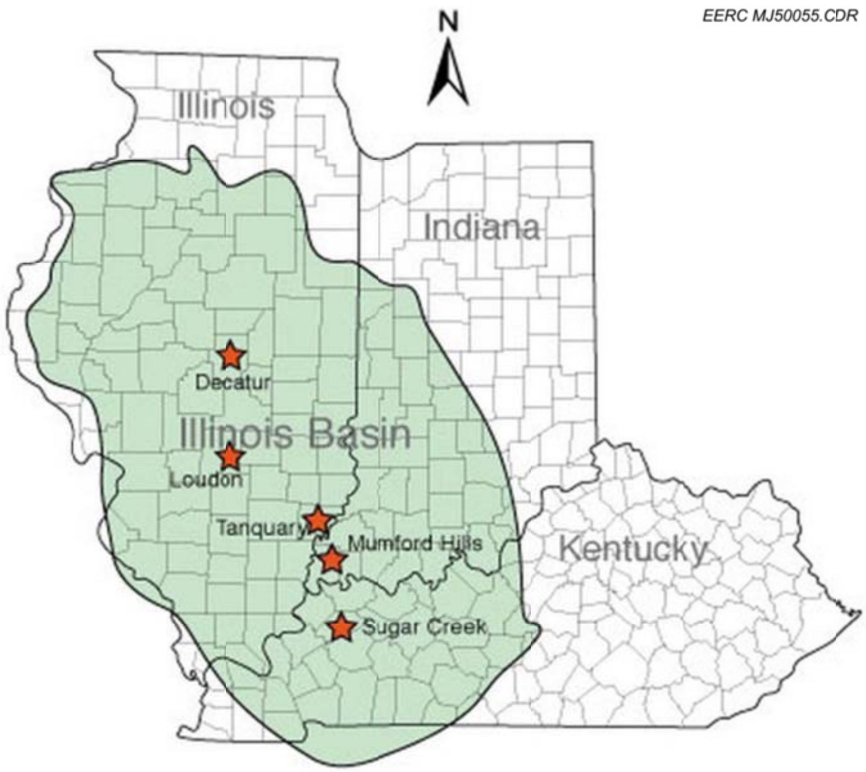


Figure 10. Map showing the location of the Illinois Basin–Decatur injection project (taken from Midwest Geological Sequestration Consortium, 2011b).

In part because of how recently the injection began at Decatur, the project has not received a great deal of academic attention. The literature available on the project has predominantly been created for public engagement work and permitting. Operational details such as intermittency of injection are not currently of great concern to the public or regulators and no data were found on the subject. It is possible that at certain points during the ongoing construction at the Decatur project site, injection may have ceased temporarily while new monitoring and injection wells were tied into the system. This could provide an opportunity to study the consequences of intermittent injection at Decatur if injection and pressure data become available.

**Table 6. Summary of Illinois Basin–Decatur Injection Project Characteristics**

| | | Reference |
|---|---|---|
| Capture | | |
| Location | Decatur, Illinois, USA | Massachusetts Institute of Technology, 2014b |
| Capture Technology | $CO_2$ from fermentation step at ethanol plant | Midwest Geological Sequestration Consortium, 2011a |
| $CO_2$ Stream Composition | 99.9% $CO_2$ | Gollakota and McDonald, 2013 |
| Number of Compressors | 4 | Gollakota and McDonald, 2013 |
| Compressor Discharge Pressure | 9.8 MPa (1421 psi), 35°C | Gollakota and McDonald, 2013 |
| Pipeline | | |
| Length | 1.8 km | DOE NETL,[a] 2013 |
| Diameter | 15.2 cm | IEA Greenhouse Gas R&D Programme, 2014 |
| Delivery Pressure | 9.8 MPa | Gollakota and McDonald, 2013 |
| Phase | supercritical | DOE NETL, 2013 |
| Capacity | 0.33 Mtonnes/yr | IEA Greenhouse Gas R&D Programme, 2014 |
| Transport Rate | 1000 tonnes/day | DOE NETL, 2013 |
| Environment | On the ethanol plant campus | DOE NETL, 2013 |
| Storage | | |
| Location | Decatur, Illinois, USA | DOE NETL, 2013 |
| Formation | Mt. Simon sandstone (Cambrian) | DOE NETL, 2013 |
| Reservoir Lithology | Quartzose sandstone | Hosa and others, 2010 |
| Porosity | 15% | Hosa and others, 2010 |
| Permeability | 225 mD | Hosa and others, 2010 |
| Thickness | 300 m | Hosa and others, 2010 |
| Pressure | | |
| Temperature | | |
| Number of Injection Wells | 1 | DOE NETL, 2013 |
| Injection Rate | 1000 tonnes/day | Hosa and others, 2010 |
| Injection Depth | 1980 m | Hosa and others, 2010 |
| Capital Cost | | |
| Entire Project | $208 million | Massachusetts Institute of Technology, 2014b |

[a] U.S. Department of Energy National Energy Technology Laboratory, 2013.

## 3.0 OPERATIONAL FLEXIBILITY OF $CO_2$ PIPELINES

Variability of a $CO_2$ stream can take two forms: variability in composition of the $CO_2$ stream itself and variability in the quantity of the $CO_2$ produced by the source with time. Some of the types of facilities that are mentioned as potential $CO_2$ sources for CCS include electricity-generating stations, biofuels facilities (such as ethanol plants), natural gas-processing facilities, cement plants, petroleum refineries, and steel plants. Each source type produces different $CO_2$ streams having somewhat different compositions from other source types. Additionally, each of the source types produces $CO_2$ at variable rates, dependent upon the process and maintenance schedule.

In addition to studying the variability in the $CO_2$ stream(s) produced by different types of $CO_2$ sources, the effects of the stream variability on pipeline operation, health and safety issues, and costs were investigated. Pipelines that carry commodity (as opposed to specialty) $CO_2$ will have to be flexible so as to accommodate at least some variation in composition and/or mass flow rate (Serpa and others, 2011). Methods for dealing with stream variability during pipeline operation, especially when multiple sources and/or sinks are involved, were explored. The findings are discussed in the subsections that follow.

### 3.1 Variability of $CO_2$ Sources and Their Captured $CO_2$ Streams

There are three opportunities (called platforms) for capturing $CO_2$ from fossil fuel combustion systems, whether for power generation or at an industrial facility: before (pre), during (through combustion modification), and after (post) combustion. The specific categories of $CO_2$ capture technologies that are available for use in one or more of these platforms include absorption, adsorption, membranes, and other techniques such as mineralization, reduction, and cryogenic methods (Cowan and others, 2011).

Precombustion removal refers to near-complete capture of the $CO_2$ prior to fuel combustion and is usually implemented in conjunction with gasification (of coal, coke, waste biomass, or residual oil) or steam reforming/partial oxidation of natural gas to produce syngas, which contains carbon monoxide (CO) and hydrogen ($H_2$). Subsequent conversion by the water–gas shift reaction produces $CO_2$ from the CO, resulting in $H_2$-rich syngas. This syngas (often with nitrogen added for temperature control) can be combusted in gas turbines, boilers, or furnaces. Purified $H_2$ can be used in fuel cells. Typical $CO_2$ stream concentrations before capture are 25 to 40 vol% at pressures ranging from 2.48 to 5.0 MPaA. This high partial pressure of $CO_2$, relative to that of combustion flue gas, enables separation to be performed using physical solvents. A physical solvent utilizes the pressure-dependent solubility of $CO_2$ in the solvent (as opposed to a chemical reaction with the solvent) to separate the $CO_2$ from the mixed-gas stream (Cowan and others, 2011). Water present in the $CO_2$ stream would be removed prior to pipeline transport.

With process modification, a concentrated stream of $CO_2$ can be generated during combustion in a process called oxygen combustion, or oxycombustion. Substitution of pure oxygen for the combustion air produces a $CO_2$-rich flue gas that requires minimal processing before use or permanent storage. Theoretically, the $CO_2$ can be recovered by compressing, cooling, and dehydrating the gas stream to remove traces of water that are generated during combustion. When the end use requires it, any noncondensable contaminants that may be present such as $N_2$, nitrogen oxides, oxygen ($O_2$,) and argon can be removed by flashing in a gas–liquid separator (Cowan and others, 2011).

The most common $CO_2$ separation platform is postcombustion, where the $CO_2$ is removed from low-pressure, low-$CO_2$-concentration flue gas following other pollution control devices so that the postcombustion sorbent (either an amine solvent or a dry adsorbent) or membrane is not deleteriously impacted by the non-$CO_2$ flue gas components. Several types of postcombustion processes have been and are being developed to separate and remove the $CO_2$ from a flue gas stream, such as absorption, adsorption, membrane, and cryogenic processes and other methods that include mineralization for either disposal or to produce a mineral product and reduction to produce beneficial products such as fuels and/or plastics (Cowan and others, 2011). This is the type of $CO_2$ capture technology that would be the most likely to be applied at existing conventional coal-fired power plants in the near term because it has been applied commercially at other industrial facilities, although not at such a large scale as would be required for a utility. Other capture technologies could be applied in the future, especially at new-build facilities. Choice of a $CO_2$ capture technology will be made based on energy policy, power generation and technology match, and the power industry history at that location. Space for the capture plant, power to run the capture plant, and heat integration between the power production and the $CO_2$ capture plants would be required, irrespective of capture technology chosen.

In a presentation given at the "EC FP7 Projects: Leading the way in CCS Implementation" conference, Porter (2014) presented a summary comparison of the impurities that are estimated by the $CO_2$QUEST project to be present in $CO_2$ streams from the three platforms. These data are reproduced in Table 7.

**Table 7. Summary of Impurities in $CO_2$ Streams from the Three Capture Platforms**

| | Oxycombustion | | | | |
|---|---|---|---|---|---|
| Component | Raw/ Dehumidified | Double Flashing | Distillation | Precombustion | Postcombustion |
| $CO_2$, vol% | 74.8–85.0 | 95.84–96.7 | 99.3–99.4 | 95–99 | 99.6–99.8 |
| $O_2$, vol% | 3.21–6.0 | 1.05–1.2 | 0.01–0.4 | 0 | 0.015–0.0035 |
| $N_2$, vol% | 5.80–16.6 | 1.6–2.03 | 0.01–0.2 | 0.0195–1 | 0.045–0.29 |
| Ar, vol% | 2.3–4.47 | 0.4–0.61 | 0.01–0.1 | 0.0001–0.15 | 0.0011–0.021 |
| $NO_x$, ppm | 100–709 | 0–150 | 33–100 | 400 | 20–38.8 |
| $SO_2$, ppm | 50–800 | 0–4500 | 37–50 | 25 | 0–67.1 |
| $SO_3$, ppm | 20 | – | 20 | – | N.I. |
| $H_2O$, ppm | 100–1000 | 0 | 0–100 | 0.1–600 | 100–640 |
| CO, ppm | 50 | – | 50 | 0–2000 | 1.2–10 |
| $H_2S$/COS, ppm | | | | 0.2–34000 | |
| $H_2$, ppm | | | | 20–30000 | |
| $CH_4$, ppm | | | | 0–112 | |

Different industrial processes and different capture technologies can produce captured $CO_2$ streams that have somewhat different compositions. In general, postcombustion amine scrubbing processes will produce very similar streams, irrespective of flue gas source. The same is true for precombustion capture and oxycombustion processes. Examples of $CO_2$ stream compositions for electric power generation (both pulverized coal [PC] and integrated gas combined-cycle [IGCC]), cement manufacture, petroleum refining, coke production, and lime manufacture were reported by Porter (2014) and Last and Schmick (2011) and are shown in Tables 7 and 8. While reported typical impurities for postcombustion processes are relatively low (except perhaps for water), precombustion technologies could contain up to a few percent hydrogen or $H_2S$/COS and oxycombustion could carry a couple of percent of oxygen and nitrogen as well as water (Porter, 2014). De Visser and others (2008) prepared a $CO_2$ quality recommendation that was based upon the ENCAP project as well as health, safety, and operational considerations. The recommendations developed by de Visser and others are based on precombustion processes and take into account multicomponent cross-effects (such as between water and $H_2S$ and water and methane) on $CO_2$ transport. Irrespective of its composition, once the $CO_2$ has been captured, it is dehydrated to remove water and compressed for transport via pipeline to the geologic storage site.

**Table 8. $CO_2$ Stream Compositions of Nonenergy Emitters**

| | MEA Refinery[a] | MEA Cement Plant[a] | Cement Kiln[b] | Coke Production[b] | Lime Production[b] |
|---|---|---|---|---|---|
| $CO_2$, vol% | 99.6 | 99.8 | 99.00 | 99.4 | 99.52 |
| $N_2$, vol% | 0.29 | 0.0893 | | | |
| CO, ppmv | 1.2 | 1.2 | 1620 | 701 | 2000 |
| Ar, ppmv | 11 | 11 | | | |
| $H_2O$, ppmv | 640 | 640 | | | |
| $NO_x$, ppmv | 2.5 | 0.86 | 3330 | 1690 | 1100 |
| $SO_x$, ppmv | 1.3 | <0.1 | 4410 | 3030 | 1800 |
| CO, ppmv | 1.2 | 1.2 | | | |
| $O_2$, ppmv | 35 | 35 | | | |
| $CH_4$, ppmv | | | | 206 | |
| Cl, ppmv | 0.41 | 0.41 | 65.7 | 26.89 | |
| Ash, ppmv | | 5.7 | | | |
| Hg, ppmv | | 0.00073 | 0.1 | | |
| As, ppmv | 0.29 | 0.0029 | | | |
| Se, ppmv | 1.2 | 0.0088 | | | |
| VOC, ppmv | | | | 96.9 | |
| TOC, ppmv | | | 81 | | |

[a] Porter (2014).
[b] Last and Schmick (2011).

Because many species can be present in a captured $CO_2$ stream, stream composition standards have been developed to ensure the safety of stream transport and the structural integrity of a pipeline that might carry $CO_2$ emanating from more than one source. One such standard that is used in the United States is the Kinder Morgan specification, which is provided in Table 9. Other specifications (such as the Dynamis $CO_2$ quality recommendation mentioned previously that is based on the ENCAP project) could be used instead. The limits specified are the upper boundaries, with various species present in lower concentrations. It should be noted that the Kinder Morgan specification would not have to be applied to pipelines that are only intended to carry $CO_2$ from one source to a single geologic sink. In such a case, the pipeline would be designed specifically to the stream composition requirements. A specification is a useful tool to ensure that $CO_2$ can be transported safely and that streams from multiple sources that will be transported in a single pipeline meet at least minimum standards such that the bulk product that is delivered also will meet the minimum standards.

$CO_2$ capture can be applied to an industrial or utility process at whatever rate makes the most economic sense. Most solvent-based capture processes capture at least 90% of the $CO_2$ they contact, and typically, this value is closer to 95%. Irrespective of the capture technology used, the equipment can be sized to capture a specific amount of the $CO_2$ produced by the source. If the equipment is sized to treat less than the entire stream, some of the flue gas will bypass the capture plant. It may be advantageous to capture less than 95% of the $CO_2$ if a contract for a certain amount of $CO_2$ has been negotiated or if there are no regulatory drivers specifying a higher capture rate. It may also be possible to operate a $CO_2$ capture facility differently than its design specifications, such as capturing to meet varying customer demand and economics or capturing to the limit of the pipeline capacity when the pipeline is shared by multiple sources. In both cases, the remaining $CO_2$ would be emitted. These options certainly would not be the most economic manner for continued operation and would likely be done only if there were a significant driving force to do so.

**Table 9. Kinder Morgan Specifications for Pipeline Transport of Carbon Dioxide (Havens, 2008)**

| Species | Specification | | Reason |
|---|---|---|---|
| $CO_2$ | 95 mol% | Minimum | MMP[a] |
| $N_2$ | 4 mol% | Maximum | MMP |
| Hydrocarbons[b] | 5 mol% | Maximum | MMP |
| Water[c] | 30 lb/MMcf (~600 ppm by weight) | Maximum | Corrosion |
| $O_2$ | 10 ppm by weight | Maximum | Corrosion |
| $H_2S$ | 10–200 ppm by weight | Maximum | Safety |
| Total Sulfur | 35 ppm by weight | Maximum | Health and safety |
| Glycol[d] | 0.3 gal/MMcf | Maximum | Operations |
| Temperature | 120°F | Maximum | Pipeline coating |

[a] Minimum miscibility pressure.
[b] In addition, the dew point of the $CO_2$ stream (with respect to hydrocarbons) must be <–29°C (–20°F).
[c] No free water.
[d] At no time may the glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

### *3.1.1 Power Plants*

In 2013, roughly 28% of the global $CO_2$ emissions from fossil fuel combustion were attributed to coal-fired power plants (Olivier and others, 2013). Power plants built in the 1990s and early 2000s typically have been designed for baseload operation with a main objective of producing electricity at minimum cost (Domenichini and others, 2013). Variable electricity demand, coupled with increased use of renewable energy sources such as solar and wind (which are themselves variable sources) and the relatively poor flexibility of low-$CO_2$ generation technologies such as nuclear, means that power plants will need to be capable of flexible operation (Ferrari and others, 2012).

At a conventional coal-fired power plant, the exhaust gas from the boiler may be cleaned of sulfur and nitrogen oxides, particulate, and/or mercury using various processes such as a selective catalytic reduction system or selective noncatalytic reduction system (for nitrogen oxide reduction), a flue gas desulfurization unit (for sulfur oxide removal), a baghouse or electrostatic precipitator (for particulate), and carbon injection (for mercury removal). These pollution control devices would be employed if a plant were to capture its $CO_2$ because most carbon capture technologies require the flue gas be scrubbed to very low levels of these materials prior to capture.

#### *3.1.1.1 Composition of the $CO_2$-Rich Stream Leaving a Conventional Coal-Fired Power Plant*

In general, a conventional coal-fired power plant produces a flue gas having the relative proportions of components shown in Table 10. A postcombustion process that makes use of amines to separate the $CO_2$ from the rest of the flue gas is the technology that is most likely to be applied to an existing coal-fired power plant because that technology has been demonstrated at commercial scale for other applications. Coal composition does not substantially affect the composition of the $CO_2$ stream produced because the requirements of existing amine processes (and other solvents as well) dictate that the flue gas be scrubbed to very low levels of $SO_x$ and $NO_x$ so as to limit the production of heat-stable salts that take a portion of the amine out of service, which is likely to be economically untenable because of the cost of the amine. Even with $NO_x$ and $SO_x$ reduction systems, most amine-based capture technologies will require a final polishing to reduce the concentration of these species to ultralow levels prior to introducing the flue gas to the amine scrubber. Particulate and mercury would also be removed to very low levels prior to the amine scrubbing. This processing scheme renders most flue gases very similar at the entrance to the capture technology after which the amine itself removes virtually all of any remaining $SO_x$, $NO_x$, and particulate. Once the $CO_2$ stream is dehydrated and compressed in preparation for pipeline transport, it is likely that it will be very pure, containing very small amounts of nitrogen, oxygen, and water. This purity will not likely change substantially even if other capture technologies are used, because they virtually all require the same flue gas pretreatment and produce very similar $CO_2$ streams.

**Table 10. Relative Concentrations of Components in Raw Flue Gas from a Conventional PC Power Plant and a $CO_2$ Stream Separated Using Amine Absorption**

| Component | Relative Proportions in Flue Gas,[a] vol% | Estimated Composition of $CO_2$ Stream from Amine Absorption,[a] vol% | Estimated Composition of $CO_2$ Stream After Dehydration,[b] vol% | Estimated Composition of $CO_2$ Stream from MEA Absorption,[c] vol% |
|---|---|---|---|---|
| $CO_2$ | 13.5 | 93.2 | 99.75 | 99.7 |
| $SO_2$ | 0.016 | Trace | | <0.0001 |
| $SO_3$ | 0.00325 | Trace | | |
| $N_2$ | 74.7 | 0.17 | 0.18 | 0.18 |
| $NO_2$ | 0.0025 | | | 0.00015 |
| $NO_x$ | 0.06 | Trace | | |
| HCl | 0.00525 | | | |
| $O_2$ | 4 | 0.01 | 0.01 | 0.006 |
| $H_2O$ | 7.7 | 6.5 | 0.06 | 0.064 |
| Hydrocarbons | Trace | Trace | | |
| Metals | Trace | Trace | | |
| $Hg^{2+}$ | Trace | | | |

[a] From Last and Schmick, 2011.
[b] Estimated by removing water to ~640 ppm and normalizing the remaining components that are present in larger than trace amounts. This level of water can be thought of as a maximum concentration for consideration for transport in a pipeline. In fact, it is quite likely that the amount of water present would be lower. This calculation provides the "least pure" stream composition.
[c] From Porter, 2014.

#### *3.1.1.2 Variability/Intermittency of $CO_2$ Streams from a Coal-Fired Power Plant*

The amount of $CO_2$ produced by a power plant depends upon the electricity demand and its variation with time. Demand can vary during the day as well as seasonally over the course of a year. This can be seen in Figure 11, which is a plot of the system load on the PJM Interconnection during 2012. The PJM Interconnection is a regional transmission organization (RTO) in the United States that coordinates the movement of wholesale electricity and manages the high-voltage electricity grid to ensure reliability for consumers in 13 northeastern U.S. states and the District of Columbia. The emission of $CO_2$ is directly proportional to the production of electricity. It is not possible to assign exact $CO_2$ emission values to this plot because it represents the power produced by hundreds of power plants, not all of which use the same fuel or produce $CO_2$ at the same rate. However, an estimate of the amount of $CO_2$ that would be produced while generating this power can be made. Information from the U.S. Energy Information Administration (2014b), shows that $CO_2$ is produced during coal-fired power generation at the rate of 0.95 tonne/MWh and at a rate of 0.54 tonne/MWh when natural gas is fired. From Figure 11, it appears that the average power plant load of the PJM Interconnection is roughly 100,000 MW each day, or a total of about 876 TWh for the year. Assuming that the fuel used to produce the power is split evenly between coal-fired plants and natural gas-fired facilities, Figure 11 would represent the emission of 1.78 Mtonnes each day, or 0.65 Gtonnes $CO_2$ for the year. This type of variation in system load with time of day and season is experienced by all fossil fuel-fired power stations, irrespective of location. A description of daily and seasonal

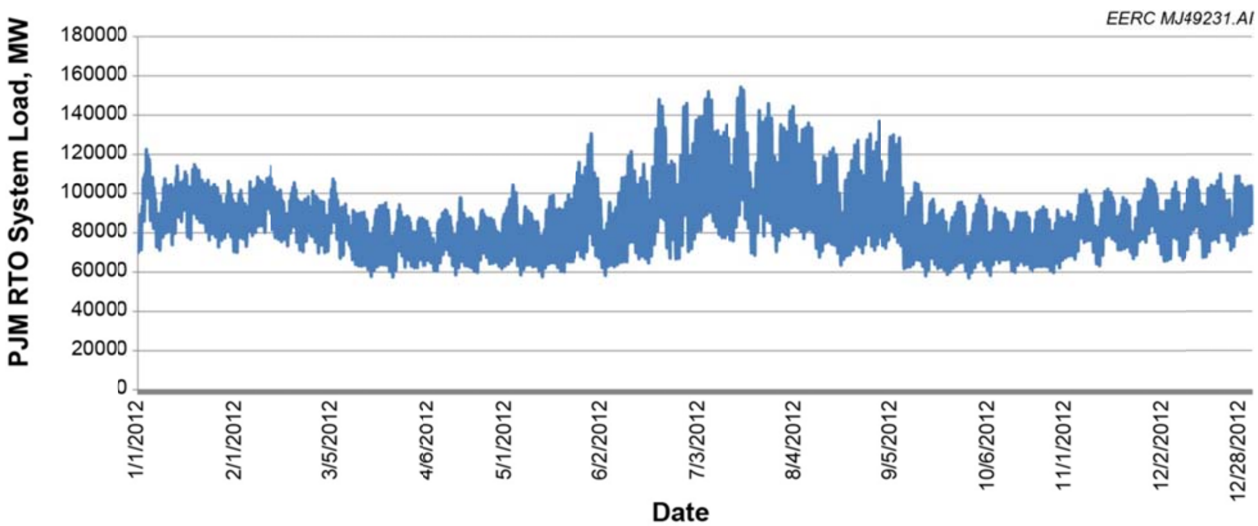


Figure 11. Variation in the system load (and therefore, the emission of $CO_2$) of the PJM Interconnection RTO during 2012.

variations in electricity demand in the United Kingdom is given in an article entitled "Seasonal variations in electricity demand" (Gavin, 2014).

During an interview, engineers at an electric power company in the midwestern United States indicated that $CO_2$ emissions are based on the load of the unit(s), which can be fairly constant for 8–12 hour with only minimal change. At other times, the load can change, either higher or lower, at the rate of 1%–2% a minute. The 1% to 2% rate change can sometimes continue in the same direction for as long as 30–45 minutes. Because the changes are completely at the whim of the market, the plant operations team is not able to predict the load on an hour-to-hour basis. The engineers pointed out that the $CO_2$ concentrations in the flue gas were fairly constant across the load range, varying from 10% at low load to 12% at high load, which they felt was typical for a coal-fired power plant burning the type(s) of coal burned at their facilities. A $CO_2$ capture plant associated with an electricity-generating station will be forced to adapt to this type of variation in both quantity of $CO_2$ produced and in the flue gas composition with time. Determining exactly how a capture plant would be operated in order to deal with these variations is outside of the scope of this project.

### *3.1.2 Cement Plants*

The cement industry accounts for about 5% of all of the $CO_2$ emissions produced globally (Rubenstein, 2012). Approximately 1 tonne of $CO_2$ is produced for every tonne of cement (Rubenstein, 2012). $CO_2$ is produced directly through the calcination process; this accounts for about 50% of the $CO_2$ emissions from a cement plant (Rubenstein, 2012). $CO_2$ is also produced indirectly by burning fossil fuels to heat the kiln (equaling roughly 40% of the emissions) as well as by producing the electricity needed for the remaining cement plant machinery and during transport of the cement product (totaling about 5% to 10% of the $CO_2$ emissions). A simplified process flow diagram showing the steps in the cement-manufacturing process and gaseous emission locations is shown in Figure 12.

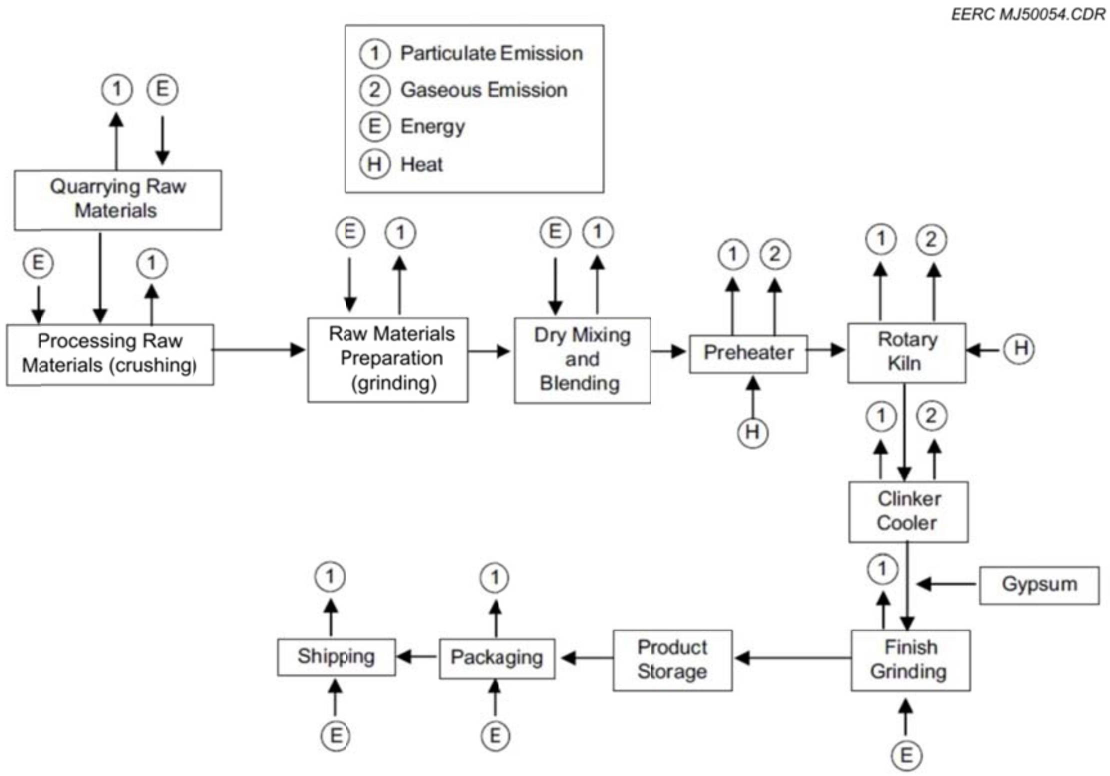


Figure 12. Flow diagram of the cement-manufacturing process (taken from Huntzinger and Eatmon, 2009).

#### *3.1.2.1 Composition of the $CO_2$-Rich Stream Leaving a Cement Facility*

Life cycle assessments carried out for the industry point to the parts of the process where emissions can be expected. Emissions that are available for compression are found in the raw meal preparation and the pyroprocess steps.

There are four main pyroprocessing routes for the production of cement: wet process, semiwet process, semidry, and dry process (IEA Greenhouse Gas R&D Programme, 2008). In the United States, the processes are described as wet, long dry, preheater, and precalciner (Greer, 2003; Marceau and others, 2010). Each process type can have multiple gas vents that can remain independent or combined to exit via a main stack. Therefore, the composition of the gas stream available for $CO_2$ capture can be highly variable and, at each facility, depends upon the fuels used, the configuration of the process, the ratio of clinker to cement, and the venting configuration.

The IEAGHG's 2008 report on $CO_2$ capture in the cement industry reported emission information primarily from European sources looking at various clinker/cement ratios and fuels used. Table 11 summarizes their findings. Marceau and others (2010) reported emission data for cement production in the United States. These data are presented in Table 12.

**Table 11. Process Emissions from Cement Production, Primarily in Europe (summarized from IEA Greenhouse Gas R&D Programme, 2008)**

| Component | Wet Process | Dry Process |
|---|---|---|
| $CO_2$ (calcination), kg/kg of clinker produced | 0.5 (estimated) | 0.5 (estimated) |
| $CO_2$ (kiln fuel), kg/kg of cement produced [a,b] | 0.36–1.09 | 0.28–0.89 |
| | kg/tonne clinker | |
| No distinction of process type for components given below | | |
| $O_2$, % | 10% (typically) | |
| $NO_x$ (as $NO_2$), kg/tonne clinker | <0.4–6 | |
| $SO_2$, kg/tonne clinker | <0.02–7 | |
| Dust, kg/tonne clinker | 0.01–0.4 | |
| HF, kg/tonne clinker | <0.0008–0.01 | |
| HCl, kg/tonne clinker | <0.002–0.05 | |
| Dioxins/Furans, mg/tonne clinker | <0.002–0.001 | |
| Metals, mg/tonne clinker | | |
| Total Hg, Cd, Tl | 200–600 | |
| Total As, Co, Ni, Se, Te | 2–200 | |
| Total Sb, Pb, Cr, Cu, Mn, V, Sn, Zn | 10–600 | |

[a] Emissions from electricity consumption are included.
[b] Clinker content (clinker/cement ratio) varies from 0.5 to 0.95.

**Table 12. U.S. Pyroprocess Emissions from Fuel Combustion[a] and Calcination (Marceau and others, 2010)**

| | Wet | Long Dry | Preheater | Precalciner | Average |
|---|---|---|---|---|---|
| Emission | kg/tonne of Cement | | | | |
| Particulate Matter, total | 0.280 | 0.347 | 0.148 | 0.152 | 0.201 |
| $CO_2$ | 1090 | 1000 | 846 | 863 | 918 |
| $SO_2$ | 3.87 | 4.79 | 0.262 | 0.524 | 1.65 |
| $NO_x$ | 3.49 | 2.88 | 2.28 | 2.00 | 2042 |
| VOC[b] | 0.0548 | 0.00991 | 0.00304 | 0.0507 | 0.0380 |
| CO | 0.0624 | 0.103 | 0.469 | 1.77 | 1.04 |
| $CH_4$ | 0.0544 | 0.0096 | 0.00269 | 0.0501 | 0.0375 |
| $NH_3$ | 0.00472 | 0.00479 | 0.00475 | 0.00476 | 0.00476 |
| HCl | 0.043 | 0.055 | 0.0013 | 0.065 | 0.0446 |
| Hg | 5.51E-05 | 8.43E-05 | 2.69E-05 | 6.94E-05 | 6.24E-05 |
| Dioxins and Furans, TEQ[c] | 6.53E-11 | 3.69E-10 | 2.38E-12 | 9.97E-11 | 9.97E-11 |

[a] Includes mobile equipment allocated to the pyroprocess step. According to the source, mobile equipment makes up 15% of the reported emissions.
[b] VOC – volatile organic compounds.
[c] TEQ – toxicity equivalence.

A wide range of concentrations of exhaust gas components, believed to be a generalized worldwide average, was reported by Ali and others (2011). This average concentration is given in Table 13.

**Table 13. Average Exhaust Gas Concentration from the Cement Process (Ali and others, 2011)**

| Component | Concentration |
|---|---|
| $CO_2$ | 14%–33% (w/w) |
| $NO_2$ | 5%–10% of $NO_x$ |
| $NO_x$ | <200–3000 mg/Nm$^3$ |
| $SO_2$ | <10–3500 mg/Nm$^3$ |
| $O_2$ | 8%–14% (v/v) |

A report issued in 2009 by the European Cement Research Academy (ECRA) examined the feasibility of $CO_2$ capture from clinker production. Emission data from German cement kilns were collected and are presented in Figures 13 and 14. The distribution of $SO_x$ shows concentrations below 100 mg/m$^3$ for the majority of kilns, while the average $NO_x$ concentration is about 410 mg/m$^3$.

It would be possible to apply $CO_2$ capture to a cement plant. The most appropriate approaches would be either oxycombustion or postcombustion processes (IEA Greenhouse Gas R&D Programme, 2008). At a cement plant, oxycombustion is the process in which the fuel used to heat the kiln is burned in a pure-oxygen environment and $CO_2$-rich flue gas is recycled to the burner to control the combustion temperature. Theoretically, oxycombustion would produce a flue gas that has a very high concentration of $CO_2$ and would require little postseparation processing. However, it is likely that some type of stream purification would still be required (IEA Greenhouse Gas R&D Programme, 2008). According to IEA Greenhouse Gas R&D Programme (2008), application of oxycombustion to a cement plant may require the following:

- A process redesign in order to prevent excessive equipment wear.
- A second combustion point using recycled $CO_2$ if a precalciner is used.
- An assessment of the effects on the process chemistry, particularly the calcination process.
- A better understanding regarding whether or not the plant can be made sufficiently free of air in-leakage to prevent dilution of the concentrated $CO_2$ stream.
- On-site $CO_2$ storage may be required to maintain appropriate burner temperature during periods when there may not be enough $CO_2$ from the exhaust gases to recycle, such as at start-up.

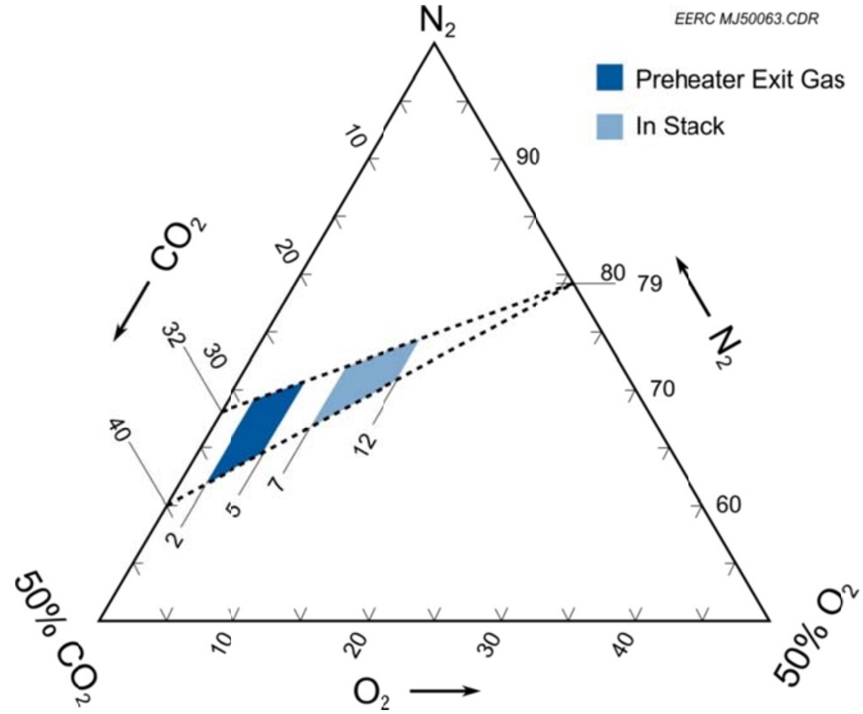


Figure 13. Dry gas composition of cement kiln gas after preheater and in stack (European Cement Research Academy, 2009)

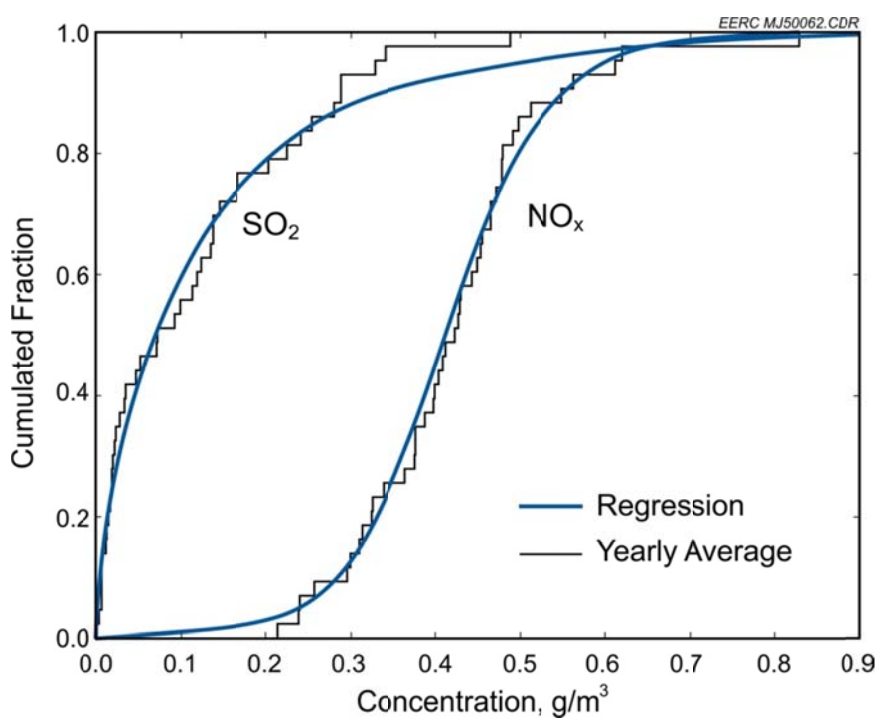


Figure 14. Distribution of $SO_x$ and $NO_x$ in cement kiln flue gases (European Cement Research Academy, 2009).

Efficient, cost-effective application of almost any postcombustion $CO_2$ capture process to a cement plant would require the same unit operations that a coal-fired power plant would require, i.e., processes that can dramatically reduce $SO_x$, $NO_x$, particulate, and mercury levels (IEA Greenhouse Gas R&D Programme, 2008). In addition, there would be additional space, power, and heat integration requirements (IEA Greenhouse Gas R&D Programme, 2008). The IEA Greenhouse Gas R&D Programme report (2008) concludes that postcombustion capture could be readily retrofitted to existing cement plants, assuming that there is enough space at the cement plant for the capture facility but that further research and development are needed to address technical issues with applying oxycombustion to a cement plant. If an amine scrubbing technology were applied to a portland cement plant, the expected composition of the concentrated $CO_2$ stream that would be produced is given in Table 14.

##### *3.1.2.2 Variability/Intermittency of the $CO_2$ Stream from a Cement Plant*

Cement plants do not run continuously. According to an engineer familiar with cement plants, some plants may only run for a month at a time every few months depending on the demand for product. When the plants are running, raw mill maintenance will reduce the amount of $CO_2$ produced. The raw mill is where the raw materials are ground prior to calcining in the kiln. The frequency of the raw mill maintenance depends on the age of the raw mill, the type of mill, the type of process, and the type(s) of products, but it can be as often as once every 7 to 10 days. Because the kiln is kept hot during the raw mill maintenance, $CO_2$ will still be produced by the fuel used to heat the kiln, but the stream will be greatly reduced, perhaps by half. Offgas from the kiln often exhibits large spikes of mercury or other metals that are present in the fuel but have been associated with the interior walls of the kiln. The kiln tends to run hotter when the raw material is not being fed for calcining. Some compounds are released by the elevated temperatures when the kiln gets hotter than is typical and could affect the composition of the $CO_2$ stream during maintenance periods.

**Table 14. Summary of Emission Factors and Relative Proportions for Portland Cement Kilns (Last and Schmick, 2011)**

| Component | Relative Percentage[a] |
|---|---|
| Total Organic Carbon | 0.008% |
| CO | 0.162% |
| $CO_2$ | 99.048% |
| $NO_x$ | 0.333% |
| $SO_2$ | 0.441% |
| HCl | 0.007% |
| Acetone | 0.000% |
| Benzene | 0.001% |
| Toluene | 0.000% |
| Chloromethane | 0.000% |
| Benzoic Acid | 0.000% |
| Bis(2-ethylhexyl)phthalate | 0.000% |
| Phenol | 0.000% |
| Hg | 0.000% |

[a] Values rounded to thousandths place.

Many challenges still exist for the cement industry with respect to capture of $CO_2$. A considerable challenge is the source of the additional heat needed for solvent regeneration in a postcombustion capture environment. Most facilities are isolated and are not near existing facilities that can generate the heat needed for regeneration. Other capture processes may be more suited for cement facilities but would require process or plant modification. Requirements for heat and/or modifications to the existing system will greatly affect the economic benefit and, for many sites, the costs of deploying $CO_2$ capture would be too great.

### *3.1.3 Petroleum Refineries and $H_2$ Production*

Even though the cumulative amount of $CO_2$ emissions from petroleum refineries is a small fraction of the emissions from electric power plants, the volume of $CO_2$ that refineries produce is substantial. Reports by large emitters to the U.S. Environmental Protection Agency (EPA) in 2012 indicate that U.S. petroleum refineries emitted approximately 9% as much $CO_2$ as power plants. That value represents about 193 million tonnes of annual $CO_2$ emissions (U.S. Environmental Protection Agency, 2012). In addition to being substantially smaller in magnitude, emissions from a typical refinery are also more heterogeneous than those from a typical power plant due to multiple disparate emission sources, such as the oxygen-fired fluidized catalytic cracking unit catalyst regenerator, various furnaces, and natural gas-based hydrogen production.

#### *3.1.3.1 Variability/Intermittency of the $CO_2$ Streams from a Refinery*

A refinery is a collection of different processing units that are optimized to accept a range of crude oil feedstocks for the economical production of a range of products. The specific ranges of feedstocks and products are determined by the particular design of the refinery. While it may be said that there are generic configurations, such as hydrocracking for enhanced diesel production or fluidized catalytic cracking for gasoline production, in fact, there are no "standard" refineries; each is different. Refineries differ in the amount of $CO_2$ produced per barrel of oil that is processed by the plant overall as well as in the relative amounts produced by similar processing units across plants. This is shown in several tables. Table 15 shows $CO_2$ intensities for a few U.S. refineries. Note that carbon intensity is not a function of size. Rather, it is a function of refinery feedstock and configuration, and it varies from year to year. Table 16 notionally depicts $CO_2$ intensity for different refinery configurations by product on a tonne $CO_2$-per-tonne product basis. Table 17 shows the distribution of $CO_2$ emissions by source within a notional refinery. As indicated by Tables 15–17, within a refinery there are multiple, different $CO_2$ sources whose relative contributions to refinery $CO_2$ emissions varies by process (source). Table 18 shows a typical refinery $CO_2$ emission profile, while Table 19 shows how $CO_2$ emissions can be assigned to processes across a notional refinery.

The difference in the fluidized catalytic cracking unit (FCCU) regenerator's fraction of emissions in Tables 16–18 provides some insight into variation from refinery to refinery—or perhaps between U.S. refineries, which tend to have more FCCUs, and European refineries, which tend to have fewer. The $CO_2$ Capture Project has stated that FCCU emissions typically represent 20%–30% of total refinery $CO_2$ emissions ($CO_2$ Capture Project, 2013).

**Table 15. $CO_2$ Intensities for a Few Select U.S. Refineries During 2010 and 2012 (Oil and Gas Journal, 2009; U.S. Environmental Protection Agency, 2010; U.S. Environmental Protection Agency, 2012)**

| Refinery | Capacity, bbl/d | 2010<br>kg $CO_2$/bbl oil | 2012<br>tonne $CO_2$/tonne oil |
|---|---|---|---|
| Cross Oil & Refining, Smackover, AR | 7000 | 27.8, 0.208 | 23.4, 0.175 |
| Phillips 66, Wilmington & Carson, CA | 138,700 | 52.1, 0.391 | 50.2, 0.377 |
| ExxonMobil, Baytown, TX | 576,000 | 51.3, 0.385 | 45.9, 0.345 |

Note: Intensity in tonne $CO_2$/tonne oil assumes 37.2° API (American Petroleum Institute) or 7.5 bbl/tonne and 1 bbl product/bbl crude oil.

**Table 16. Notional $CO_2$ Emissions (tonne $CO_2$/tonne product) from Different Refinery Configurations (Hydrocarbon Publishing Company, 2010)**

| Configuration | LPG | Gasoline | Diesel | Fuel Oil | Overall |
|---|---|---|---|---|---|
| HSU[a] | 0.297 | 0.287 | 0.138 | 0.185 | 0.205 |
| HSU + VBU[b] +FCCU[c] | 0.943 | 0.416 | 0.172 | 0.374 | 0.337 |
| HSU + VBU + HCU[d] | 0.362 | 0.500 | 0.174 | 0.290 | 0.325 |
| HSU + DCU + HCU | 0.318 | 0.420 | 0.171 | 0.503 | 0.329 |
| HSU + VBU + FCCU + HCU | 0.478 | 0.414 | 0.204 | 0.445 | 0.362 |

[a] Hydroskimming unit.
[b] Visbreaking unit.
[c] Fluidized catalytic cracking unit.
[d] Hydrocracking unit.

**Table 17. Distribution of Refinery $CO_2$ Emissions by Source for a Notional U.S. 250,000-BPD Refinery (data originally produced by the American Petroleum Institute; reproduced in Hydrocarbon Publishing Company, 2010)**

| Source | Fraction of Refinery $CO_2$ Emissions |
|---|---|
| Steam Boilers | 22.3% |
| Process Heaters | 20.3% |
| Engines and Turbines | 7.4% |
| Flares and Incinerators | 3.1% |
| Hydrogen Unit Vent | 10.8% |
| FCCU Regenerator | 35.4% |
| Purchased Electricity | 0.6% |

**Table 18. Typical $CO_2$ Refinery Emissions Profile (Taraphdar, 2011)**

| Source | Fraction of Refinery $CO_2$ Emissions |
|---|---|
| Process Heaters | 50% |
| Utilities | 30% |
| Hydrogen Plant | 16% |
| FCCU Regenerator | 4% |

**Table 19. Notional Emissions from a 235,000-BPD Refinery (Ferguson and others, 2011)**

| Source | Fraction of Refinery $CO_2$ Emissions |
|---|---|
| Fluidized Catalytic Cracking Unit | 21% |
| Crude and Vacuum Distillation Units | 17% |
| Natural Gas Boilers | 16% |
| Hydrogen Unit | 13% |
| Continuous Catalytic Reforming Unit | 12% |
| Visbreaking Unit | 7% |
| Fuel Oil Boilers | 4% |
| Gas Turbine Generator | 4% |
| Other | 5% |

#### *3.1.3.2 Composition of the $CO_2$-Rich Streams from a Refinery*

The relative contributions of these processes can also vary within a single refinery because crude oil feeds vary and the relative performances of the processes vary over time. The process units differ with respect to choice of capture technologies that could appropriately be applied to each and the compositions (under normal and upset conditions) of the captured streams. In other words, the composition and rate of $CO_2$ produced from a given refinery vary as the relative processing rates of different units vary. The composition variation across units can be reduced if the same capture technology is applied across the refinery, but this might not be the least-cost approach.

Emissions from boilers, heaters, and utilities are amenable to capture by a wide range of postcombustion, oxycombustion, and precombustion $CO_2$ capture technologies. However, such is not the case for hydrogen and fluidized catalytic cracking units which, by their nature, are not compatible with precombustion technologies. This is unfortunate because the locations of refinery emission sources tend to be widely distributed around the refineries, which means that collecting $CO_2$ emissions for capture involves large amounts of awkward ductwork. This situation is avoided by precombustion because capture can be centralized and limited to hydrogen units. The effects of refinery processes being able to accept a variety of capture technologies include the following:

- Should the same postcombustion capture technology be successfully applied to all refinery units, the composition of the $CO_2$ sent to the pipeline could be relatively consistent, even if flow rates change.

- If oxycombustion capture is successfully applied to all refinery units, oxygen likely would appear in the captured product and its level might vary from unit to unit so that both the composition and flow rate of $CO_2$ to the pipeline could vary.

- If precombustion were applied to all refinery units except the hydrogen units and FCCUs, and if the hydrogen units and FCCUs adopt the same postcombustion capture technology, the composition of the $CO_2$ sent to the pipeline could be relatively consistent, even if flow rates change.

- If the hydrogen units and FCCUs adopt different technologies, then the potential exists for significant variation in $CO_2$ stream composition caused by variation in relative emission rates from the hydrogen units and FCCUs.

- If capture technologies vary from unit to unit, the potential exists for variation in composition as well as rate.

A mixture of postcombustion and oxycombustion technologies have the potential to provide the largest variation in composition and capture rate at a refinery, especially if disturbances, upsets, process failures, or other factors make controlling impurity levels in the captured $CO_2$ a challenge. Even so, it is feasible that captured $CO_2$ purities of 95% to 99% would be possible if applying oxycombustion capture on FCCUs ($CO_2$ Capture Project, 2013). However, it is unlikely that a very low oxygen concentration of less than 10 ppm by weight could be obtained at a refinery without extraordinary dilution by another source. If refineries adopt oxycombustion capture and use dilution to reduce oxygen concentrations to acceptable levels, it is likely that the variation in oxygen concentrations in the captured stream or variations in the relative flow rates of the oxycombustion and diluent streams would vary pipeline oxygen concentrations. Oxygen is undesirable in pipelines because of its ability to enhance corrosion and in reservoir injection streams because it can enhance reservoir microbial activity (Melzer, 2013). It can also react exothermically with hydrocarbons. The greater oxygen's concentration in the stream, the greater its activity. Some researchers have advocated for extremely low oxygen limits—on the order of 5 ppb—as a means of reducing pitting corrosion in injection well tubulars (King, 2009), although how such a low concentration could be reliably measured can be questioned. Other researchers note that general oxygen corrosion occurs in wet conditions (IEA Greenhouse Gas R&D Programme, 2010). Even if the oxygen level cannot be reduced to ultralow levels, nearly complete drying of the $CO_2$ stream should greatly reduce the potential for general oxygen corrosion. Corrosion-resistant pipeline materials could be used if it were not possible to reduce the oxygen and/or water levels to sufficiently low levels.

Even though there are about 140 operating refineries in the U.S. (U.S. Energy Information Administration, 2014e), and hundreds of other refineries elsewhere in the world, reports in the open literature of $CO_2$ capture facilities processing refinery emissions are rare. Two facilities that have been reported capturing significant volumes of $CO_2$ are Shell's Pernis refinery in Rotterdam, the Netherlands, and Valero's refinery in Port Arthur, Texas, USA. Not surprisingly both are capturing $CO_2$ from hydrogen production unit syngas streams in which $CO_2$ is more concentrated than conventional combustion flue gas streams and thus is easier to capture. About 450,000 tonnes of $CO_2$ a year is captured from the Pernis refinery for use in beverages and by greenhouses to enhance plant growth. The captured $CO_2$ is compressed to 2.2 MPaA and transported in the vapor phase to the greenhouses through a 97-km steel transmission pipe and a 200-km high-density polyethylene distribution network (Atlas Copco, 2014; OCAP, 2012). About 44,000 tonnes of $CO_2$ a year is captured from two of Air Products' hydrogen plants that are associated with the Port Arthur refinery. Hydrogen from the plants goes either to the refinery or into a nearly 1000-km hydrogen pipeline that receives from 20 other hydrogen plants and supplies refineries and industrial facilities. $CO_2$ captured from the plants is injected into the Denbury Green Pipeline, which supplies $CO_2$ to oil fields for EOR. The hydrogen pipeline and a geologic source of $CO_2$ on the $CO_2$ pipeline endow the Port Arthur plants with significant independence. The hydrogen plants need not vary operations to match the refinery because the hydrogen pipeline can absorb excess hydrogen product or make up for deficient production, nor do the plants need to vary operations to match oil recovery needs because flow from the geologic $CO_2$ source can be modulated to perform a similar function on the $CO_2$ pipeline. This permits the plants to operate steadily at an optimal rate when possible or vary rates because of internal conditions when necessary. Ultimately, this should reduce variation from the plants.

This study was unable to ascertain either from the open literature or from a contact with one of the sources the observed effects of variability and upset conditions upon refinery $CO_2$ capture, flow rates, and composition. Even if some insight were acquired, it could be questioned as to how representative one or two hydrogen facilities are of future petroleum-refining situations that might not be as "forgiving" (i.e., might be more constrained because of stricter $CO_2$ emissions regulation and absence of a geological $CO_2$ source to accommodate for refinery variations). Perhaps a differentiator of petroleum refining versus other industries is the possibility of a heterogeneous collection of capture technologies within a single plant that introduces a greater variety of problems and potentially a greater range of $CO_2$ stream compositions.

### *3.1.4 Gas-Processing Plants*

Gas-processing facilities separate the various hydrocarbons and fluids from the pure natural gas acid gases from raw natural gas (Naturalgas.org, 2014). Oil and condensate is often removed in equipment located at or near the wellhead. Free water can be removed by simple separation at or near the wellhead but water vapor is removed through dehydration using glycol or solid desiccant. Natural gas liquids can be removed using absorption or cryogenic expansion, while acid gases ($H_2S$ and $CO_2$) are removed from the natural gas stream using amines or iron sponges (Naturalgas.org, 2014). Acid gas removal can be performed by many processes, including chemical solvents (generally amines), physical solvents, and membrane systems (Kohl and Nielsen, 1997). Choosing a process depends on the process economics and effectiveness. Solvent cost, equipment cost, and the energy required for regeneration are the most important factors when selecting a process (El Ela, 2014).

#### *3.1.4.1 Composition of the $CO_2$-Rich Stream Leaving a Natural Gas-Processing Plant*

Once dried and compressed, the $CO_2$-rich stream from a gas-processing plant can be fairly pure. The average $CO_2$ vent stack compositions for the ConocoPhillips Lost Cabin Gas Plant in Wyoming, USA, are presented in Table 20. The composition and metered volume of vent stack gas that is supplied to the CRC pipeline in Texas, USA, for EOR and measured by five separate metering systems at the McCamey hub is given in Table 21. As the tables both show, at >94 vol%, $CO_2$ makes up a significant percentage of the gas stream.

### 3.1.4.2 *Variability/Intermittency of $CO_2$ Stream from a Natural Gas-Processing Plant*

Table 21 also presents the total metered volume for the time frame from July 2004 through July 2006. This provides an indication of the variability in quantity of the $CO_2$ stream, showing that the same quantity of $CO_2$ is not always flowing through the pipeline.

**Table 20. Average $CO_2$ Vent Stack Composition for Lost Cabin Gas Plant (Lohnes, 2007)**

| Component | Train I | Train II | Train III |
|---|---|---|---|
| $CO_2$, mol% | 98.318 | 98.447 | 98.273 |
| $CH_4$, mol% | 1.472 | 1.389 | 1.550 |
| $C_2H_6$, mol% | 0.016 | 0.015 | 0.027 |
| $N_2$, mol% | 0.103 | 0.057 | 0.052 |
| COS, mol% | 0.091 | 0.092 | 0.098 |
| $H_2S$, ppm | 5 | 4 | 8 |

**Table 21. Metered Sales Gas Volume and Composition by Month (Blue Source, LLC, 2006)**

| | | Gas Composition, mol% | |
|---|---|---|---|
| Month–Year | Metered Volume, kscm$^{3}$[a] | $CO_2$ | $CH_4$ |
| July 2004 | 44,721 | 96.437 | 2.196 |
| August 2004 | 45,911 | 95.921 | 2.707 |
| September 2004 | 40,338 | 95.711 | 2.943 |
| October 2004 | 50,141 | 96.588 | 2.34 |
| November 2004 | 47,069 | 96.588 | 2.34 |
| December 2004 | 50,247 | 97.409 | 1.347 |
| January 2005 | 55,598 | 95.122 | 3.699 |
| February 2005 | 54,125 | 95.141 | 3.919 |
| March 2005 | 69,008 | 95.141 | 3.919 |
| April 2005 | 56,820 | 95.455 | 3.4 |
| May 2005 | 56,603 | 97.106 | 1.721 |
| June 2005 | 52,281 | 96.145 | 2.605 |
| July 2005 | 59,073 | 96.662 | 2.148 |
| August 2005 | 62,852 | 96.705 | 1.97 |
| September 2005 | 61,171 | 94.564 | 4.255 |
| October 2005 | 59,659 | 94.564 | 4.255 |
| November 2005 | 54,915 | 94.453 | 4.46 |
| December 2005 | 56,984 | 95.422 | 3.615 |
| January 2006 | 53,815 | 95.681 | 3.202 |
| February 2006 | 47,951 | 96.849 | 1.23 |
| March 2006 | 59,661 | 97.348 | 1.863 |
| April 2006 | 60,160 | 95.595 | 3.364 |
| May 2006 | 66,145 | 96.398 | 2.698 |
| June 2006 | 61,639 | 94.91 | 4.107 |
| July 2006 | 62,346 | 94.824 | 4.188 |

[a] At U.S. oil and gas standard conditions of 15.56°C and 0.101 MPa.

### *3.1.5 Ethanol Plants*

Ethanol plants are considered to be among the easiest facilities from which to capture $CO_2$. The ethanol process involves a fermentation step that produces a wet and nearly pure $CO_2$ stream. Typically, the offgas from the ethanol fermentation step is sometimes rinsed to remove any ethanol and is then dehydrated and compressed for pipeline transport.

#### *3.1.5.1 Composition of the $CO_2$-Rich Stream Leaving an Ethanol Plant*

At the ADM ethanol plant in Decatur, Illinois, USA, $CO_2$ is collected at atmospheric pressure from the corn-to-ethanol fermenters using a 0.91-m pipeline. It is compressed to 0.24 MPa and sent via a 0.61-m, 0.45-km pipeline to a dehydration and compression facility where it is compressed and dehydrated to about 9.8 MPaA and 35°C.The dehydrated $CO_2$ contains less than 0.005 wt% moisture and is >99.9 vol% $CO_2$ purity (U.S. Department of Energy National Energy Technology Laboratory, 2014). This is the $CO_2$ stream that is being injected into the Mt. Simon Sandstone in the Illinois Basin–Decatur Project mentioned earlier in this document.

#### *3.1.5.2 Variability/Intermittency of $CO_2$ Stream from an Ethanol Plant*

According to the Renewable Fuels Association, ethanol production in the U.S. varies from month to month (Renewable Fuels Association, 2014). There is a direct correlation between fuel ethanol production and $CO_2$ production. In general, $CO_2$ is produced at an average rate of 0.79 kg/L of anhydrous ethanol produced (Patzek, 2004).

Figure 15 shows the variability on a weekly basis for $CO_2$ emissions during fuel ethanol production in the U.S. from May 2010 to August 2014. The variability is caused by changes in driving habits, which affect the demand for the finished product, as well as high prices for the material used in ethanol production (e.g., corn). When the cost to produce the ethanol is too high for profitability or the market decreases, some ethanol plants may be idled (MPRNews, 2012).

## 3.2 Effect of Variability on Pipeline Operation

### *3.2.1 Vapor-Phase Transport vs. Supercritical Transport*

$CO_2$ can be transported either in a vapor phase or as a supercritical fluid. A supercritical fluid has the viscosity of a gas but the density of a liquid. The most efficient method of transporting $CO_2$ in a pipeline is as a supercritical fluid near its critical point (Seevam and others, 2008). It is likely that the economics of most CCS projects will require that $CO_2$ be transported in its supercritical phase because vapor-phase transport would require considerably larger diameter pipelines for the same mass flow rate (Eldevik, 2008) and would experience high pressure drops (Seevam and others, 2008). Vapor-phase transport is not used for pipelines that carry significant quantities of $CO_2$ for long distances (Seevam and others, 2008). Approximately 400,000 tonnes of $CO_2$ are moved each year in vapor phase through the OCAP pipeline to about 500 greenhouse companies in the western part of the Netherlands (OCAP, 2012). The authors could not find information about other vapor-phase $CO_2$ pipelines that are in use at this time.

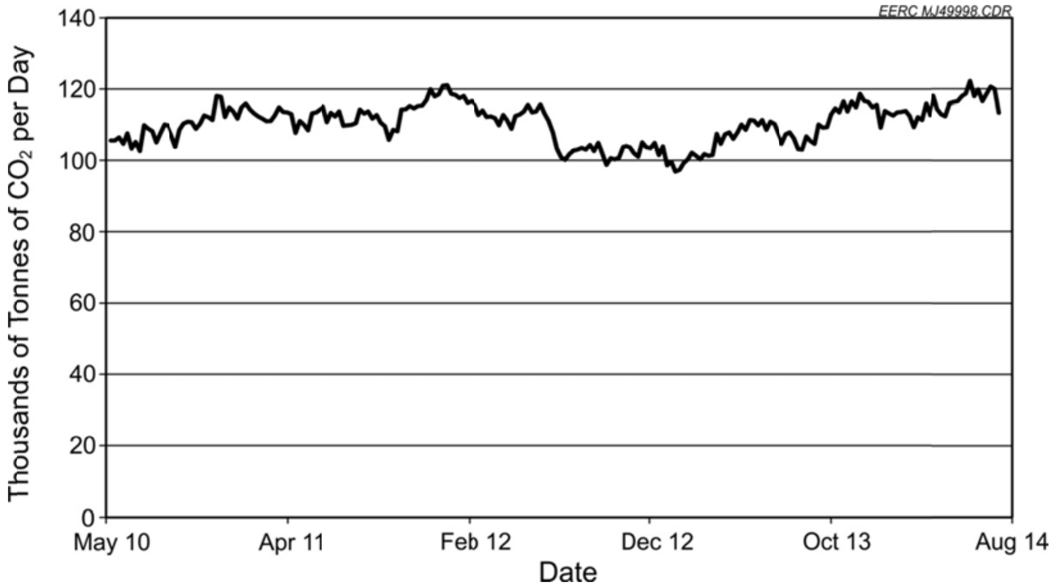


Figure 15. Weekly variation in the emission of $CO_2$ during the production of fuel ethanol in the United States. (Fuel ethanol production data from U.S. Energy Information Administration, 2014d).

### *3.2.2 Offshore vs. Onshore Pipelines*

Compressor stations are used to boost the $CO_2$ stream pressure so as to maintain single-phase flow and ensure that the $CO_2$ stream arrives at the geologic sink at the expected pressure. Compressor stations are typically found every 161 km (100 mi) on onshore pipelines, depending on the topography, starting pressure, and target pressure at the end of the pipeline. Compressor stations tend to be impractical for offshore pipelines (Ogden and Johnson, 2010; Downie and others, 2010; IEA Greenhouse Gas R&D Programme, 2009). Instead of using compressor stations that would be difficult to maintain in an undersea environment, the pressure of the $CO_2$ within an offshore pipeline must be sufficiently high to maintain single-phase flow over the full length of the pipeline. Variations in pressure could therefore cause more issues with maintaining single-phase flow in an offshore pipeline than in an onshore pipeline. Lengthy offshore pipelines may be larger in diameter than their onshore equivalents so that pipeline pressure can be maintained (Ogden and Johnson, 2010). Offshore pipeline design must take into account not only the change in pressure between the inlet and the outlet, but also the gravity head gain caused by the decrease in elevation. Therefore, the allowable pressure drop is greater for offshore than onshore pipelines, and this may actually reduce the diameter required for some offshore pipelines (Ogden and Johnson, 2010).

Seasonal variations in temperature are likely to affect onshore pipelines more than offshore pipelines (Det Norske Veritas, 2010) where the temperature of the water changes little relative to the air or ground temperature. The temperature of the ground surrounding a buried onshore pipeline varies seasonally and therefore impacts the amount of $CO_2$ that is transported through the pipeline.

### *3.2.3 Effect of Flow Rate Variability*

#### *3.2.3.1 Temperature, Pressure, and Topography Effects*

Temperature affects pipeline capacity indirectly as well as directly because the operating temperature affects not only the amount of $CO_2$ that can be compressed to fit the pipeline, but also other factors, such as viscosity (Serpa and others, 2011). Temperature changes to which the pipeline is exposed and the subsequent changes in pressure can affect the ability to maintain pipeline pressure within an acceptably narrow operating margin. Supercritical-phase conditions should be retained at the designed operating conditions. Therefore, pipeline pressure control systems must be designed and operated in a manner that ensures maintenance of the operating conditions as well as at pipeline shut-in conditions (Det Norske Veritas, 2010). When the topography over which the pipeline is built changes significantly (such as up and down mountains and valleys), it is possible for the $CO_2$ pressure to change, potentially forming multiphase flow. If this happens, it can cause transport difficulties such as when liquid $CO_2$ pools in the low spots simultaneously when vapor-phase $CO_2$ forms. Two-phase flow is more likely to occur when the pipeline is oversized relative to the amount of $CO_2$ that is transported.

On the other hand, Munkejord and others (2013) state that two-phase flow need not necessarily be avoided in pipelines and injection wells. As knowledge about the Sleipner reservoir has increased and there is a better understanding of the flow conditions, it is apparent that the flow at the wellhead is in two-phase flow and that there is a gradual phase change inside the well itself. It should be remembered that Sleipner has a short transport distance and no rotating equipment is installed that could be damaged by the two-phase flow (Munkejord and others, 2013).

Pressure oscillations may cause gas bubbles to form in the dense phase, altering its behavior and potentially damaging the pipeline. Cavitation may occur when the pressure suddenly drops lower than the bubble point of the $CO_2$ (Behrla and others, 2010).

#### *3.2.3.2 Capture Facilities–Power Plant Load Variations*

Traditional power plants have been designed for base-load operation, but there is discussion that power plants (at least those in Europe) may soon be required to operate more flexibly, i.e., at more variable loads in response to the changing market (Domenichini and others, 2013). Capture of $CO_2$ from a facility operating at variable loads will mean that the quantity of the $CO_2$ stream that is fed to the pipeline could vary significantly with time. This can be dealt with partly by turning down the compressors but there is a point at which the compressors cannot be turned down further. In this case, it would be useful to have multiple [smaller] $CO_2$ compressors or variable frequency drives to enable additional turndown (Domenichini and others, 2013).

Klinkby and others (2011) used simulations to study transient variations in terms of pressure, temperature, and phase. During injection with full load from the power plant, they found that $CO_2$ would be in the supercritical state in both the pipeline and the well. The pressure and temperature drop below the critical point (7.1 MPaA and 31°C) during shutdown and the phase changes from dense phase to gas and liquid in both the upper part of the well and the pipeline. Low loads of less than 20% of full load will have difficulty maintaining supercritical conditions in the pipeline and well because of the combination of lower pressure and temperature (Klinkby and others, 2011). Their simulations also indicated that the pressure in the reservoir near the well area reacts almost instantaneously to a sudden discontinuation in the $CO_2$ injection.

Additional information about the effect of the capture plant on pipeline operation is given in the "Pipeline First Fill, Start-Up, and Shutdown Procedures" subsection.

### *3.2.4 Effects of Impurities*

As was shown in the "Variability of $CO_2$ Sources" section of this report, the composition of an anthropogenic $CO_2$ stream depends on both the process producing the stream and the method of capturing that stream. The presence of impurities (Seevam and others, 2008):

- Changes the physical and transport properties of $CO_2$.
- Affects the $CO_2$ hydraulics, which in turn affects the number of compressors, compressor power, temperature transients, etc.
- Changes other aspects such as fracture propagation, corrosion, nonmetallic component deterioration, and the formation of hydrates and clathrates.
- Changes the capacity of the pipeline itself.

Impurities change the critical temperature and pressure of the $CO_2$ stream, typically by increasing them. Hydrogen, for example, increases the critical temperature and pressure, which reduces the optimum pipeline operating region (Seevam and others, 2008). Because operation in the two-phase region should be minimized so as to optimize cost and throughput, the pipeline pressure must be maintained above the $CO_2$ stream's critical point.

The number and interaction of the impurities must be taken into account. The critical temperature and pressure increase with the presence of additional impurities as well as with increasing impurity concentration (Seevam and others, 2008). The impurities can have a significant effect not only on the critical temperature and pressure, but also on the density and viscosity of the fluid. Some combinations (e.g., if $H_2$ or $N_2$ are present) cause higher pressure and temperature drops for a given length of pipeline than other combinations. This can affect the distance between compressor stations for onshore pipelines. Sudden temperature drops can cause embrittlement and/or hydrate formation, either of which can damage a pipeline (Downie and others, 2010). Variability in $CO_2$ composition can also affect the injection infrastructure and/or the geologic storage formation. In some cases, this may require that a well be shut in or vented.

The U.S. Department of Energy National Energy Technology Laboratory has issued $CO_2$ Impurity Design Parameters as part of their Quality Guidelines for Energy System Studies (Herron and Myles, 2013). In the guidelines, they provide recommended limits for $CO_2$ stream impurities required by the pipeline, EOR applications, and by a saline reservoir. Table 22

**Table 22. Recommended Limits for $CO_2$ Stream Compositions**

| Component | Unit[a] | Carbon Steel Pipeline | | EOR | | Saline Reservoir Sequestration | | Saline $CO_2$ and $H_2S$ Cosequestration | | Venting Concerns |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Concept | Literature Range | Concept | Literature Range | Concept | Literature Range | Concept | Literature Range | |
| $CO_2$ | vol% | 95 | 90–99.8 | 95 | 90–99.8 | 95 | 90–99.8 | 95 | 20–99.0 | Yes; IDLH[b] 40,000 ppmw |
| $H_2O$ | ppmw[c] | 300 | 20–650 | 300 | 20–650 | 300 | 20–650 | 300 | 20–650 | |
| $N_2$ | vol% | 4 | 0.01–7 | 1 | 0.02–2 | 4 | 0.01–7 | 4 | 0.01–7 | |
| $O_2$ | vol% | 4 | 0.01–4 | 0.01 | 0.001–1.3 | 4 | 0.01–4 | 4 | 0.01–4 | |
| Ar | vol% | 4 | 0.01–4 | 1 | 0.01–1 | 4 | 0.01–4 | 4 | 0.01–4 | |
| $CH_4$ | vol% | 4 | 0.01–4 | 1 | 0.01–2 | 4 | 0.01–4 | 4 | 0.01–4 | Yes; asphyxiate, explosive |
| $H_2$ | vol% | 4 | 0.01–4 | 1 | 0.01–1 | 4 | 0.01–4 | 4 | 0.01–4 | Yes; asphyxiate, explosive |
| CO | ppmv[d] | 35 | 10–5000 | 35 | 10–5000 | 35 | 10–5000 | 35 | 10–5000 | Yes; IDLH 1200 ppmv |
| $H_2S$ | vol% | 0.01 | 0.002–1.3 | 0.01 | 0.002–1.3 | 0.01 | 0.002–1.3 | 75 | 10–77 | Yes; IDLH 100 ppmv |
| $SO_2$ | ppmv | 100 | 10–50,000 | 100 | 10–50,000 | 100 | 10–50,000 | 100 | 10–50,000 | Yes; IDLH 100 ppmv |
| $NO_x$ | ppmv | 100 | 20–2500 | 100 | 20–2500 | 100 | 20–2500 | 100 | 20–2500 | Yes; IDLH NO=100 ppmv, $NO_2$=200 ppmv |
| $NH_3$ | ppmv | 50 | 0–50 | 50 | 0–50 | 50 | 0–50 | 50 | 0–50 | Yes; IDLH 300 ppmv |

[a] Maximum unless otherwise noted.
[b] Immediately dangerous to life and health.
[c] Parts per million by weight.
[d] Parts per million by volume.
[e] Not enough information.

Continued…

**Table 22. Recommended Limits for $CO_2$ Stream Compositions (continued)**

| | | Carbon Steel Pipeline | | EOR | | Saline Reservoir Sequestration | | Saline $CO_2$ and $H_2S$ Cosequestration | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Component | Unit[a] | Concept | Literature Range | Concept | Literature Range | Concept | Literature Range | Concept | Literature Range | Venting Concerns |
| COS | ppmv | Trace | Trace | 5 | 0–5 | Trace | Trace | Trace | Trace | Lethal at high concentrations (>1000 ppmv) |
| $C_2H_6$ | vol% | 1 | 0–1 | 1 | 0–1 | 1 | 0–1 | 1 | 0–1 | Yes; asphyxiant, explosive |
| $C_3$+ | vol% | <1 | 0–1 | <1 | 0–1 | <1 | 0–1 | <1 | 0–1 | |
| Particulate | ppmv | 1 | 0–1 | 1 | 0–1 | 1 | 0–1 | 1 | 0–1 | |
| HCl | ppmv | N.I.[e] | N.I | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | Yes; IDLH 50 ppmv |
| HF | ppmv | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | Yes; IDLH 30 ppmv |
| HCN | ppmv | Trace | Trace | Trace | Trace | Trace | Trace | Trace | Trace | Yes; IDLH 50 ppmv |
| Hg | ppmv | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | Yes; IDLH 2 $mg/m^3$ (organo) |
| Glycol | ppbv | 46 | 0–174 | 46 | 0–174 | 46 | 0–174 | 46 | 0–174 | |
| MEA | ppmv | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | MSDS Exp. Limits 3 ppmv, 6 $mg/m^3$ |
| Selexol | ppmv | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | N.I. | |

[a] Maximum unless otherwise noted.
[b] Immediately dangerous to life and health.
[c] Parts per million by weight.
[d] Parts per million by volume.
[e] Not enough information.

presents these limits. Several contaminants have common specific issues relative to $CO_2$ stream composition and its transport and/or end use. For example (Herron and Myles, 2013):

- $N_2$, $CH_4$, and $H_2$ all have a lower critical temperature than $CO_2$, which would require increased pipe strength to minimize ductile fracture potential.

- Noncondensables (e.g., $N_2$, $O_2$, Ar, $CH_4$, and $H_2$) should be limited to less than 4 vol% because their presence increases the amount of compression work.

- The toxicity of CO and $H_2S$ limits their allowable concentrations because of the potential for inadvertent releases.

- The concentration of $O_2$ in $CO_2$ that will be used for EOR should be limited so as to eliminate exothermic reactions with the hydrocarbons; $H_2S$ and $SO_2$ should also be limited as they can be reproduced at the pumping well when the $CO_2$ front breaks through (Herron and Myles, 2013).

- Moisture content requirements vary and depend upon the formation of acids with $CO_2$ or $SO_2$ that can corrode standard piping.

- In the presence of free water, $O_2$ can increase cathodic reactions, causing corrosion-induced thinning of the $CO_2$ pipeline. According to some researchers, this may occur at very low oxygen concentrations (King, 2009; IEA Greenhouse Gas R&D Programme, 2010).

- The presence of $N_2$, $H_2$, and $CH_4$ increase the miscibility pressure during EOR activities and should thus be limited.

- $NO_x$ and COS can also be reproduced at the pumping well when the $CO_2$ front breaks through.

#### *3.2.5 Effects of Corrosion*

$CO_2$ readily dissolves in water to form carbonic acid, which can corrode a pipeline at a rate of 1–2 mm within 2 weeks (Eldevik, 2008). Depending on the temperature, supercritical $CO_2$ can store several hundred ppm of water. Both experimental work and experience in the field have shown that pure $CO_2$ with a dissolved water concentration that is below the saturation limit is not corrosive to carbon steel at pipeline operating conditions (Serpa and others, 2011). The water may form hydrates that can cause plugs that clog the pipeline (Eldevik, 2008). Hydrate formation is dependent on the pressure, temperature, and water content of the $CO_2$. The risk of hydrate formation is higher when the pressure is high. However, if the pressure falls, water may precipitate out and create carbonic acid (Eldevik, 2008). Clearly, variations in the temperature and pressure within a $CO_2$ pipeline caused by variability in flow rate can have a substantial effect on corrosion if any water is present in the $CO_2$ stream. These effects could be amplified if the $CO_2$ stream contains impurities that lead to changes in phase behavior at pipeline pressure.

### *3.2.6 Pipeline First Fill, Start-Up, and Shutdown Procedures*

#### *3.2.6.1 Initial Start-Up*

Following pipeline commissioning, the pipeline and compressor section are filled with dry nitrogen or dry air to a minimum pressure of 0.5 MPaG (this is enough pressure to prevent infiltration of the pipeline by wet air or water). As soon as possible, dry $CO_2$ enters the pipeline at the minimum pressure and flow rate possible by the compressor train. It is difficult to know when the pipeline has been purged of inert gas, so it is recommended that a pig be mounted in the pipeline to provide physical separation between the $O_2/N_2$ and the $CO_2$ entering the pipeline from the compressor. Upon receipt of the pig at the platform, the pipeline is allowed to pressurize to low reservoir pressure for the start-up of injection (Uilenreef and Kombrink, 2013).

Experts with $CO_2$ pipelines in the United States described the process used for first start-up of two pipelines. A pipeline is purged with dry nitrogen to dry the pipe, then is pressurized using the dry nitrogen. The nitrogen was displaced section by section using either purchased liquid $CO_2$ followed by $CO_2$ from the compressors (at one pipeline) or simply using $CO_2$ from the compressors in a section-by-section manner. Lines at the oil field were displaced with "contaminated" gas from the main pipeline and vented prior to injection so as not to introduce contaminants into the reservoir that might cause adverse reaction. Two-phase flow was not an issue during start-up as long as this procedure was followed.

#### *3.2.6.2 Normal Start-Up*

Following a planned shutdown, there are two modes of start-up that can be followed. The first mode involves pressurizing the pipeline using the full compressor flow to a pressure where flow within the pipeline is a single phase. The valves at the platform/injection site are opened to allow the gas to enter the well piping. The disadvantage of this method is that the flow will reach very high velocities in the tail end of the well piping, potentially causing vibrations and damaging the pipe. In addition, the temperature of the wellhead material must be monitored to avoid low temperatures (Uilenreef and Kombrink, 2013).

The second mode, according to Uilenreef and Kombrink (2013), is more preferable. In this approach, the well pressure control valve is opened as soon as the pressure in the pipeline has reached the wellhead pressure. The pipeline may still contain a considerable amount of liquid $CO_2$, but because of the low flow rate, the liquid slugs should not do any harm. Because of the low pressure drop near the valve at the wellhead, a minimal quantity will flow into the well piping. The low flow should not cause vibration or erosion issues in the downhole well piping. As the pipeline pressure increases, the flow rate into the well will increase.

#### *3.2.6.3 Planned Shutdown*

Start-up will be faster when the pipeline is pressurized and heated with less content. Therefore, it is advantageous to heat the pipeline content to the highest temperature possible prior to a planned shutdown. Once the "best" conditions have been reached, the compressor discharge valve is closed. The pipeline is emptied into the well as long as positive flow can be maintained. When the pressure in the well nears that of the pipeline, the valve should be shut so as to ensure that there is no backflow from the well into the pipeline (Uilenreef and Kombrink, 2013).

During stoppage of a $CO_2$ capture facility, the pressure of the $CO_2$ stream will drop and the pipeline will cool gradually until it is the same temperature as its surroundings. This may result in the formation of gas-phase $CO_2$ (and therefore two-phase flow) in the pipeline (Liljemark and others, 2011).

A planned shutdown of the $CO_2$ source requires coordination with the geologic sink. Interviews with industry indicate that sufficient advance notice allows for greater flexibility in operations. If the sink is an oil field under EOR, the oil field can simply recycle the $CO_2$ from the recovered oil to maintain continuity of operations. If the outage lasts for an extended period of time, $CO_2$ injection and/or production may need to stop, which can result in undesirable consequences.

The procedure for shutting down the pipeline would be to shut down the compressor(s) and then close the valves on the pipeline. The pipeline would then be allowed to sit at full pressure. Over time, the $CO_2$ will cool down to ground temperature, with the pressure dropping gradually as this happens. During extended outages, the pressure of the $CO_2$ within the pipeline may naturally drop to close to 6.9 MPa. At 5.5–6.2 MPa, the supercritical $CO_2$ will begin to solidify. Therefore, prior to the pipe pressure dropping that low, the pipeline is emptied and refilled when the $CO_2$ source outage is over.

In the case of the Sleipner pipeline, the hydrate control strategy is based on insulation of the pipeline so as to maintain a fluid temperature that is above the hydrate equilibrium temperature during normal operations (StatoilHydro, 2009). For lengthy planned shutdowns, the pipeline is inhibited with MEG. If the shutdown is unplanned and lengthy, the pipeline will be depressurized. Other inhibitors (wax, scale, and asphaltene) are required as well.

#### *3.2.6.4 Unplanned Shutdown*

If an emergency at the capture plant dictates an unplanned shutdown of the pipeline, the compressor discharge valve is closed to protect the contents of the pipeline. The pipeline is emptied as described under planned shutdown, except that because the pipeline may contain more $CO_2$ than during normal shutdown activity. In this case, start-up after the cooldown may take longer and care should be taken to avoid too much $CO_2$ flow into the well at too high a velocity (Uilenreef and Kombrink, 2013).

Liljemark and others (2011) modeled not only an orderly shutdown as was described in the previous text, but they also modeled a compressor trip, which would produce a fast stop. They found that the fluid in the horizontal pipeline remained in the liquid phase but that two-phase flow existed in a vertical section of pipe.

Liljemark and others (2011) also modeled a quick shutdown mode, which was like a compressor trip but with open valves. In this case, pressure waves were generated in every isolated pipe section. The mass flow rate was found to oscillate in the horizontal pipe section with an amplitude of 80 kg/s, while the flow rate in the vertical section changed less than 0.1 kg/s. The lowest pressure in the line was observed to be 1.5 MPa lower than the critical pressure, suggesting that two-phase flow is likely.

### *3.2.7 Transient Conditions*

#### *3.2.7.1 Complete Depressurization*

Pipeline depressurization, such as can occur during an accident or during planned maintenance, will cause phase transition and a strong Joule-Thomson cooling of the pipe (Munkejord and others, 2013). Depressurization of a pipeline carrying supercritical $CO_2$ can result in the deposit of a significant proportion of the $CO_2$ as a solid at low points in the pipeline (Eldevik, 2008). The temperature of these solids at atmospheric pressure is −78°C, which could cause metallurgical damage, such as embrittlement of pipe material or valves, rupture, injury, or material and infrastructure damage (Munkejord and others, 2013). If the solid is warmed rapidly, the pipeline could over-pressurize because of the rapid increase in volume as the solid sublimes to the vapor phase. This could happen by the reintroduction of supercritical $CO_2$ (Eldevik, 2008). Unless the sink could adapt and take up the additional $CO_2$, it might be necessary to vent it. The presence of impurities only makes it more difficult to model the needed conditions for safe depressurization.

Onshore pipelines utilize regular vent stations but long offshore pipelines can only be depressurized at the compression site, and it can be a lengthy process to safely depressurize while keeping the temperature above design limits (Munkejord and others, 2013). Heat-transfer coefficients are very important for the determining the total depressurization time.

Following depressurization for maintenance purposes, the pipeline will probably be started up by repressurizing the pipeline with warm, high-pressure (supercritical) $CO_2$ from the compressor train. The $CO_2$ in the pipe will change phase from gas to liquid and then to supercritical phase as the pressure and temperature are increased. OLGA simulation predicts that liquid slugs can be expected that may travel through the pipeline at relatively high speed. The details of the dynamics of this process are still uncertain and more experience is required to better understand the nature of the flow, the range of slug speeds, and the induced stresses on the pipeline (Veltin and Belfroid, 2013).

#### *3.2.7.2 Design Considerations*

Solids and cooling issues must be considered when designing a pipeline to carry supercritical $CO_2$ (Eldevik, 2008). Generally, solid formation and excessive material cooling can be avoided during normal pipeline operations but uncontrolled depressurization (as from a leak) must be considered when designing the pipeline (Eldevik, 2008). Hydrates may cause plugs that could clog the pipeline. There is some uncertainty whether free water contained in supercritical $CO_2$ would form hydrates before it forms carbonic acid, but there is a dependency on the $CO_2$ pressure, temperature, and water content (Eldevik, 2008).

The primary differences between onshore and offshore pipelines are in their design and construction. A literature review could find no mention of differences in the actual transport of the $CO_2$ within onshore versus offshore pipelines. Offshore pipelines are made of pipe having a thicker wall than onshore pipelines (so as to resist external pressure), tend to have a concrete outer coating for protection, and employ sacrificial anodes to minimize corrosion (Pigging Products and Services Association, 2014).

Typically, a conceptual design for an onshore $CO_2$ pipeline is performed as follows (Doctor and Palmer, 2005). The pipeline route must be determined and any low-lying areas identified as they might be locations for liquid holdup during variable-flow conditions. Local environmental data must be considered, including the annual variation in temperature during operation as this can affect the pipeline pressure and, therefore, its capacity. These factors should be considered when defining the physical characteristics of the $CO_2$ stream being transported, the optimal sizing and pipeline pressures to meet the needs of the project, and the mechanical design (valves, pumps, compressors, seals, etc.). Other topics of interest during a conceptual design include how the pipeline will accommodate existing and future infrastructure, safety, and corrosion protection (Doctor and Palmer, 2005; Zhang and others, 2006). Depending upon the impurities present in the $CO_2$ stream, corrosion may be more or less of an issue for a given pipeline. Prevention of longitudinal fracture is also considered during pipeline design. The fracture arrest properties of a $CO_2$ pipeline depend on the pipe wall thickness, material properties and fracture toughness, as well as the physical properties of the $CO_2$ in terms of saturation pressure and decompression speed (Det Norske Veritas, 2010). Pipelines should be designed to ensure that their fracture toughness is sufficient to arrest fracture propagation within a small number of pipe joints (Det Norske Veritas, 2010). The use of fracture arrestors on $CO_2$ pipelines is considered standard practice in the United States (Det Norske Veritas, 2010), where fracture arresters are typically installed at roughly 500-m intervals.

#### *3.2.8 Health, Safety, and Environmental Issues Associated with Flexible Pipeline Operation*

Much has been published regarding potential health, safety, and environmental (HSE) issues related to captured-$CO_2$ quality streams at pipeline conditions. It has not been possible to find much information about HSE issues that is specifically associated with flexible pipeline operation. General information that applies to all $CO_2$ pipelines is summarized here. Additional detail is included in Appendix B.

Pure $CO_2$ does not pose a health risk at typical atmospheric conditions and concentrations so it is the concentration, pressure, and impurities in pipeline $CO_2$ that create HSE issues. These issues include various effects such as:

- Physiological effects of inhaling $CO_2$, ranging from decreased blood pH to asphyxiation, depending upon concentration of $CO_2$ in the air.

- Toxic effects of inhaling impurities, such as carbon monoxide (CO) and hydrogen sulfide ($H_2S$).

- Cryogenic effects of the vapor released near a leak or rupture during depressurization.

- Environmental effects of releasing $CO_2$ and impurities, such as increased greenhouse gas emissions, noise, and vapor cloud creation.

It is also possible that $CO_2$ could create conditions that could lead to HSE issues, including:

- Rapid expansion caused by small variations in temperature affecting the pressure of the $CO_2$ within the pipeline, requiring proper engineering pressure relief controls and trained operators to prevent $CO_2$ from being trapped in a section of pipe without a pressure release, thereby causing a pipe rupture.

- Accelerated pipe corrosion if free water is present, especially in the presence of oxygen. Adhering to $CO_2$ stream specifications requiring low levels of each of these impurities will minimize the possibility of corrosion.

- Formation and accumulation of liquids or solids during depressurization.

- Rapid expansion of previously formed liquids or solids because of vaporization or sublimation.

- Degradation of pipeline components due to materials incompatibility, such as supercritical $CO_2$ attack on some polymeric, elastomeric, or other organic seals.

- Low-temperature, ductile–brittle transitional metal fracture during depressurization, such as operational depressurization of blowdown assemblies.

- Enhanced fracture propagation because of $CO_2$'s compressibility.

- Debonding and detachment of internal coatings caused by $CO_2$ permeation or solvent action.

Although the potential exists to encounter significant, adverse HSE events during operation of high-pressure $CO_2$ pipeline operations, adverse events have not been realized to an appreciable extent. In the United States, $CO_2$ has been transported by pipeline in support of EOR since 1972 (Kinder Morgan, 2014). By 2014, more than 800 million tonnes had been transported through more than 4800 km of pipelines (U.S. Department of Energy National Energy Technology Laboratory, 2010; Tanner, 2010; Kuuskraa and Wallace, 2014). Although the number of U.S. $CO_2$ pipeline leaks and accidents vary, as shown in Table 23, there have been no injuries or deaths related to $CO_2$ pipeline incidents. Appendix B contains detailed information about $CO_2$ pipeline incidents in the United States.

**Table 23. Reports of the Number of U.S. $CO_2$ Pipeline Incidents**

| Source | Time Period | Number |
|---|---|---|
| Gale and Davison (2004) | 1990–2001 | 10 |
| Parfomak and Folger (2007) | 1986–2006 | 12 |
| Parfomak et al. (2009) | 2002–2008 | 31 |
| URS (2009) | 1986–2008 | 13 |
| Watt (2010) | 1986 – March 2008 | 42 |
| U.S. Department of Transportation, Pipeline & Hazardous Materials Safety Administration (2014) | 2009–2014 (June) | 22 |

It has been noted that some characteristics of $CO_2$ make it more problematic to transport in pipelines than natural gas, such as:

- A greater susceptibility to long-running ductile fracture propagation.
- A greater likelihood of attaining lower temperatures during operations (−20°C for line venting and −80°C for leakage) because of the Joule–Thomson cooling effect, which would reduce the toughness of pipe material.
- Increased pipe wall corrosion and/or stress corrosion susceptibility of the $CO_2$ stream in the presence of free water (Demofonti and others, 2013).

Even considering these potentially problematic characteristics, incident rates in the United States have been similar to those of natural gas pipelines, with relatively little associated property damage. Table 24 compares $CO_2$ pipeline incident and property damage rates with those of natural gas and hazardous liquids pipelines during the 1990s.

These data tend to support the views expressed in the literature, namely that the decades of $CO_2$ pipeline operation for EOR and in other industries have provided design and operation experience such that wide-scale operation of $CO_2$ pipelines for onshore CCS will not pose new challenges (Carbon Sequestration Leadership Forum, 2008; ICF International, 2009). In fact,

**Table 24. U.S. Pipeline Incident Statistics[a]**

| Pipelines | Natural Gas Transmission (1986–2001) | Hazardous Liquids (1986–2001) | $CO_2$ (1990–2001) |
|---|---|---|---|
| Number Incidents | 1287 | 3035 | 10 |
| Number Fatalities | 58 | 36 | 0 |
| Number Injuries | 217 | 249 | 0 |
| Property Damage (millions of US$) | 285 | 764 | 0 |
| Incident Rate (incidents per 1000 km per year) | 0.17 | 0.82 | 0.32 |
| Property Damage (US$ per 1000 km per year) | 37,000 | 205,400 | 15,200 |

[a] 1986–2001 data are from Gale and Davison, 2004.

Snow (2009) notes that between 24,100 and 106,200 km (15,000 and 66,000 mi) of $CO_2$ pipelines will be needed by 2030 but states that the major challenges to implementing CCS are public policy and regulation rather than technical barriers associated with building the pipelines. These views were echoed by CCS and $CO_2$ pipeline experts who were interviewed for this report. The equipment and procedures associated with operation of these existing $CO_2$ pipelines have demonstrated that variation and interruptions experienced in the operation of these pipelines can be tolerated. It must be noted, however, that this confidence is associated with existing pipelines and applications, which, in North America, are all onshore.

Concern about $CO_2$ pipelines with respect to new locations and applications can be found in the literature. ICF International (2009) noted that although many technologies associated with $CO_2$ capture are mature, their application at the scale required by CCS carries commercial and technological risk. Parfomak and Folger (2007) note that integration and deployment at the scale required for CCS will be very complex. The literature has identified various complications that could be encountered when expanding this technology to new locations and applications. One complication that was mentioned both in direct communication with experts and in the literature is that the knowledge that has been accumulated is constrained because it is proprietary in nature. The Pipeline Research Council International (2014) notes that, even though $CO_2$ pipelines have been in operation in North America for decades, the majority of operational expertise is proprietary, and therefore, procedures must be redeveloped and validated through testing. Large-diameter $CO_2$ pipelines have already been used for enhanced hydrocarbon recovery in the United States and Canada, where most of the existing infrastructure is located in remote areas with a low population density. With a low population density comes a low probability of external mechanical interference (one of the most frequent causes of failure in buried pipelines). The operating experience in this setting is not applicable to European scenarios (Demofonti and Spinelli, 2011).

There is broad implication that $CO_2$ pipeline operators know how to operate $CO_2$ pipelines as well as natural gas operators know how to operate natural gas pipelines and that they know how to design for and operate with flow variability. Unfortunately, it was not possible to glean information specifically related to flow variability in the open literature or during interviews with experts that were made in conjunction with this study. Absent that information, it can be said that $CO_2$ pipeline operators know how to design for and operate existing pipelines under current conditions. It is not known exactly how this knowledge of onshore pipelines may extrapolate to:

- All aspects of offshore pipelines and $CO_2$ injection.

- Locations with higher population densities than those in the rural western United States that provide more opportunity for damage to pipelines caused by third parties and more people that could be adversely affected by $CO_2$ releases.

- Situations in which there are significant penalties for atmospheric releases.

- Situations in which source injection rates and/or sink demand rates vary with time, especially when backup sources, such as geological sources, and backup sinks, such as temporary or permanent underground storage, are not available or access is limited by pipeline capacity.

- Situations in which the $CO_2$ stream composition could change significantly, possibly over short time intervals, such as the loss of one source that injects a composition differing from other sources that inject into the same pipeline or a source that injects a composition that varies over time and with changes in operations.

- “Modest” capacity $CO_2$ pipelines. The Cortez pipeline, one of the United States’ largest $CO_2$ pipelines, has an expanded capacity of 23.6 Mtonnes $CO_2$/year, yet it can transport $CO_2$ emissions from only three 1000-MW or five 660-MW coal-fired power plants (Bliss and others, 2010; Marston, 2010; Intergovernmental Panel on Climate Change, 2005).

U.S. and Canadian $CO_2$ pipeline operators currently are in the fortunate situation that their pipelines are in low-population-density areas that do not affect nor are affected by many people. Their operations can emit $CO_2$ to the atmosphere when necessary with little risk of penalty. Their sources tend to be geologic and so are controllable and have predictable compositions. They can be matched with injection demand and pipeline design. These types of situations lead to the development of relatively reliable designs that promote safe operations. While expressing confidence in their knowledge and ability to operate within this current situation, experts interviewed for this study provided no insight as to the applicability of or ability to extrapolate current knowledge to flexible pipeline operation in other situations.

When asked about any safety implications specific to variable flow, experts interviewed for this study revealed nothing beyond information that has already been published in the open literature, such as that operators should retard valve speed to avoid water hammer and its detrimental effects and that operators should carefully monitor pipeline conditions and fluid composition to avoid the formation of solids ($CO_2$ or $CO_2$ hydrates). In the absence of industrial operating experience, it falls upon experimentation, modeling and simulation, and risk assessments to provide insight into potential HSE issues that might arise because of variation in $CO_2$ composition or flow rate when operating pipelines. In general, the experts interviewed during this study, especially those involved with EOR who have experience with pipelines in different topographies, expressed confidence in current pipeline design and operational practices such that it would be possible to account for variability in flow and that contingency plans are available that permit adaptation to variability in the short term.

Considerable experimentation by different groups has been performed to determine $CO_2$ fluid behavior in pipes during simulated rupture and depressurization (Ahmad, 2014; de Koeijer and others, 2009; Det Norske Veritas, 2014). Pipe sizes up to 50 km in length and 13,700 $m^3$ in volume were included in the experiments. Early results reported general agreement between the test results and a SINTEF-developed depressurization model (deKoeijer and others, 2009). CO2PIPETRANS data collected over several years from experiments simulating ruptures between 8.0 MPaG and 15.0 MPaG at temperatures from 0°C to 70°C were used to validate the Phast $CO_2$ discharge and dispersion model (Det Norske Veritas, 2014). Phast model predictions are said by the authors of a report on the topic to agree very well with experimental results (Witlox, 2012).

Testing was conducted to study the formation of solid $CO_2$ (i.e., dry ice) during rapid expansion. During small-scale tests, it was observed that, while approximately 30% of $CO_2$ is solidified in the expansion zone, no large formation of dry ice was observed because the freezing process is so fast that only small particles were formed. The largest-scale testing was performed at a facility in China. Full-bore rupture release experiments at this scale also exhibited formation of solid $CO_2$ particles in the pipeline. Puncture release tests exhibited temporary stabilization in pressure at points along the pipe as they approached the triple point (0.518 MPa), verifying model predictions (Mahgerefteh, 2013). The largest test that was identified during the literature search for this study employed a 50-km-long, 24-inch-diameter buried pipeline containing 9300 tonnes of $CO_2$ from a natural source with >99% purity. The pipeline was depressurized from 8.1 MPaA and 31°C to atmospheric pressure. Results were compared with predictions made by a multiphase, thermohydraulic pipeline simulation tool (OLGA® Version 5.3.2 developed by Schlumberger Production Engineering) that had recently been modified to handle single components such as $CO_2$ (Clausen and others, 2012).

During validation, models and simulators that were applied to all but the simplest or narrowly defined situations generally deviated from experimental observations. The OLGA® model is described by de Koeijer and others (2011) as performing reasonably well but that it could be improved (de Koeijer and others, 2011). Researchers and developers working with these tools have expressed the need for improvement from component-level tools, such as more accurate thermodynamic and transport property models for $CO_2$ mixtures that might appear in $CO_2$ pipelines through integrated packages that include heat-transfer, pipe-state and atmospheric-dispersion models. Even the most basic component, an equation of state that can accurately predict thermophysical properties over the range of compositions and conditions expected for $CO_2$ pipelines has been reported to need improvement, especially for mixtures with impurities. A survey paper by Aursand and others describes many of the challenges of modeling transient flow of $CO_2$-rich mixtures in pipes and developmental needs of simulators—including both more accurate thermophysical models as well as data supporting their development (Aursand and others, 2013).

Li and others (2011) published results of a literature survey of experimental data and theoretical models associated with thermodynamic properties of $CO_2$ pipeline quality mixtures at the expected range of pipeline conditions. The researchers concluded that, while some experimental data for binary mixtures of $CO_2$ with CO, $O_2$, $N_2O_4$, COS, and $NH_3$ have been published, there are few data for multicomponent mixtures. Also, there are many equations available for thermodynamic calculations of $CO_2$ mixtures, but each has weaknesses and none appear to demonstrate any clear advantage in CCS applications.

In the absence of experience, risk assessments that are based upon past experience and validated models can provide a means to identify hazards and evaluate HSE issues with $CO_2$ pipelines. Risk assessments identify possible events that have adverse consequences and then combine the likelihood of the event with the severities of potential consequences to arrive at an estimate of risk. Sources of risk that are common to pipelines in general include (Mohitpour and others, 2012):

- System design
  - Design deficiencies
  - Material inadequacy
- Operations
  - Overpressurization
  - Equipment malfunction
  - Incorrect operation
  - Human error
- Third-party impacts
  - Unintentional damage
  - Intentional damage
- Effects of environmental and terrain
  - Soil movement
  - Water movement (rain and flooding)
  - Corrosion
- Maintenance activities
  - Blowdown
  - Repairs
  - Recommissioning

A survey of $CO_2$ pipeline risk-assessment reveals that risk assessments tend to consider higher-level sources of risk as opposed to lower-level or ultimate sources. For example, they tend to consider punctures and ruptures as events themselves rather than the situations that caused punctures or ruptures, such as third-party damage or the effect of water hammer due to fast-acting valves. In this manner, Koornneef and others (2009) investigated 14 scenarios, each of which was comprised of a puncture case and a rupture case. Parameters such as pipeline diameter, length of isolated segment, failure rates, and vapor mass fraction in the release were varied to generate the 14 hypothetical scenarios. In 2012, Vianello and others (2012) performed a $CO_2$ pipeline risk assessment that considered a range of pipeline failure frequencies that were unrelated to specific events but were similar to natural gas pipeline rates. In 2013, Vianello and others ignored failure frequencies because of research by Koornneef and others (2009) that questioned the representativeness of natural gas incident statistics with respect to $CO_2$ pipelines. As opposed to Vianello and others' quantitative risk assessment, Duncan and others (2008) performed a qualitative risk assessment of case studies including the Souris River (sometimes called the Dakota Gasification Company) pipeline and the Denbury pipeline complex. The authors describe actions taken by pipeline operators to reduce risk, such as leak detection and automatic block valve closure; extensive, continuous monitoring and telemetry, especially of critical parameters (moisture, pressure, temperature, and flow rate); good mechanical and cathodic protection design; sound construction practices; and regular maintenance. The result for Denbury has been that most significant threats to pipeline operations are third-party damage and weather events that interrupt power or communications (Duncan and others, 2008). Reports of risk assessments and related techniques that were uncovered by this study, then, provide little insight into effects of variable operations on $CO_2$ pipeline HSE.

For the most part, with the exception of Ferret and others who assess the effect of impurities on HSE (Farret and others, 2014), the entities that evaluate risk do not consider causes of the releases such as corrosion or fracture propagation, much less the effects of variable operations on such phenomena. It should be noted, however, that there are individuals in the industry who are concerned about $CO_2$ pipeline HSE issues and have identified the need to understand flexibility in pipeline operations (Watt, 2012; Downie and Watt, 2011).

Risk assessments for $CO_2$ pipelines can consider experience with existing $CO_2$ and natural gas pipelines, taking into account simulation results, differences between the proposed and existing $CO_2$ pipelines, and differences between $CO_2$ and natural gas transport. Natural gas pipelines transport vapor-phase fluid, operate at lower pressures than $CO_2$ pipelines, and lack the potential corrosiveness of $CO_2$ mixtures. Therefore, their operation is often expected to be less deleterious than liquid or supercritical $CO_2$. Koornneef and others (2010) have observed that natural gas pipeline failure rates may not be valid for $CO_2$ pipelines because of its properties during transport. Failure rates for $CO_2$ pipelines based on historical accidents cannot be compared directly with rates for natural gas pipelines.

A study by Duncan and Wang (2014) of $CO_2$ pipeline risk assessments mentioned in various papers and reports states that these studies use averages for the natural gas pipeline network that include older segments that do not reflect modern pipeline technology safety levels. Therefore, drawing conclusions from the natural gas network and applying it to $CO_2$ pipelines results in individual risk of between $10^{-3}$ and $10^{-4}$. Duncan and Wang state that the likelihood of significant, potentially lethal, releases of $CO_2$ from pipelines is more likely in the range of $10^{-6}$ to $10^{-7}$, a value that would be considered acceptable to negligible in risk assessment terms.

Natural gas pipelines sometimes cycle pressure to "pack" (increase pressure in) lines as a means of storing a portion of daily demand. To a limited extent, pipeline packing could also be used with $CO_2$ pipelines to minimize flow rate variability. Pipeline packing is more effective at lower pressure. For example, assume that supercritical $CO_2$ is packed in a 320-km, 600-mm-nominal diameter (200-mi, 24-in.-diameter) onshore pipeline having a 24.6-mm (Schedule 60) wall thickness. Increasing the pipeline pressure from 8.4 MPa (1200 psig) to 10.4 MPa (1500 psig) would increase the amount of $CO_2$ by almost 8300 tonnes, while increasing the pressure from 16.0 MPa (2300 psig) to 18.8 MPa (2700 psig) would provide a much smaller increase of 2900 tonnes.

Theoretically, cycling associated with pipeline packing could lead to metal fatigue and failure, thereby becoming a source of risk by providing an opportunity for a release. Rosenfeld and Kiefner (2006) reviewed metal fatigue in pipelines and its relationship to pressure cycles. They state that fatigue due to pressure cycles is not a limiting factor for pipe that is free of gross defects. For example, fatigue in longitudinal seams caused by pressure cycles has only been observed where initial longitudinal flaws were sufficiently large, and even then only in liquid pipelines that operate in a cycle-intensive manner. Many liquid pipelines do not operate in this manner, and Rosenfeld and Kiefner note that no failures of this type have been seen in gas pipelines. This is because gas pipelines do not experience enough large pressure cycles to cause fatigue cracking that results in pipeline failure.

Infrequently, fatigue does occur in gas pipelines, although generally for reasons other than cycling pressure, such as pressure pulsations or mechanical vibration associated with the operation of reciprocating compressors, inadequate bracing of aboveground piping that is subject to vibration, or vortex-shedding on pipe that is exposed to water currents. Welding quality, design choices, and damage to the surface of the pipe often affect susceptibility as well.

A hydrostatic pressure test or in-line inspection (ILI) is unlikely to effectively identify the presence of these threats to a pipeline because of the random nature of conditions or events causing the fracture (e.g., exposure of pipe to floodwaters) as well as the mode of fracture (e.g., circumferentially). Most situations involving fatigue are best managed through observation of conditions that might be conducive to fatigue, engineering evaluation on a case-by-case basis, and corrective action as appropriate (Rosenfeld and Kiefner, 2006).

Modeling/simulation and risk assessments that have been collected through interviews or uncovered in the open literature provide little basis for understanding or accurately forecasting the effect of variable flow rates on pipeline HSE performance. However, safe operation of $CO_2$ pipelines begins with a design basis for the pipeline that establishes source compositions and conditions with an appropriate safety margin. Most (if not all) $CO_2$ pipelines in existence in North America are overdesigned for their current application; i.e., they are designed for higher flow rates and operating pressures through the use of thicker walls and/or larger diameters. For example, the Denbury Greencore Pipeline was designed to transport up to 13.9 Mtonnes/yr (725 MMcf/d) in the future, although initially only 0.96 Mtonnes/yr (50 MMcf/d) are being transported (Denbury, 2014). Adequate instrumentation and automation resources that enforce pipeline constraints will be required to detect and respond in a timely manner to excursions from the specified composition and conditions, thereby preventing their entrance into the pipeline. Interviews with industry experts suggest that in at least some applications, the $CO_2$ composition is being monitored. In general, they feel that it is possible to adapt to variable $CO_2$ supply rates as well as some variability in composition; however, specific details were not shared.

## 3.3 Methods for Dealing with Variability

### *3.3.1 Process Control Strategies for Flexible Pipeline Operation*

#### *3.3.1.1 Hubs*

$CO_2$ pipeline hubs are locations at which $CO_2$ transported by pipeline from multiple supply points is merged for subsequent transport to a single formation or multiple geologic storage formations, often by multiple pipelines. The hubs do not adhere to a specific $CO_2$ purity or set of operating conditions (IEA Greenhouse Gas R&D Programme, 2013a). At the hubs, the $CO_2$ can be dispatched as needed and as might be required to minimize variability in mass flow rate in the pipeline network and/or satisfy contract terms (interruptible vs. noninterruptible flow agreements). Globally, there are many examples of $CO_2$ pipeline hubs, some of which are in operation while others are being planned or discussed for the future.

##### 3.3.1.1.1 Denver City

Kinder Morgan $CO_2$ Company, L.P., operates the hub in Denver City, located in western Texas, USA. The Denver City hub is the largest $CO_2$ hub in the world. It distributes $CO_2$ from the Cortez Pipeline, which is 808 km (502 mi) long and 76 cm (30 in.) in diameter and has a capacity of 30.4 $Mm^3$/d (1.2 to 1.3 Bcfd) which, Kinder Morgan announced, will be expanded to nearly 56 $Mm^3$/d (20 Bcfd) (Wuerth, 2014). This equates to 63.125 ktonnes/day at oil and gas company standard conditions of 15.56°C and 0.101 MPa (60°F and 1 atm).

3.3.1.1.2 McCamey

The McCamey Hub is located southeast of the Denver City Hub where the Canyon Reef Carriers (224 km in length and 40.6 cm in diameter) and Central Basin Pipeline (230 km long and 40.6 cm in diameter) intersect. These pipelines each have a capacity of 10.69 ktonnes/day at oil and gas company standard conditions of 15.56°C and 0.101 MPa (60°F and 1 atm).

3.3.1.1.3 Rotterdam

The Rotterdam Hub is being built in phases, with the first phase consisting of infrastructure to move $CO_2$ in vapor phase to greenhouses. The OCAP pipeline currently supplies about 400,000 tonnes of $CO_2$ each year to about 500 greenhouses in the western portion of the Netherlands. The steel transport pipeline is 97 km in length. A high-density polyethylene pipeline system totaling 200 km in length is used to distribute the $CO_2$ to the greenhouses (OCAP, 2012).

3.3.1.1.4 $CO_2$ Hubs in the United Kingdom

Subsurface storage sites in the Central North Sea contain ample $CO_2$ storage for the United Kingdom's fossil fuel-fired power plants. The Central North Sea contains different types of storage and has an added benefit of the opportunity for $CO_2$ EOR (Scottish Carbon Capture and Storage, 2012). A Yorkshire and Humber CCS cluster and associated shared-user $CO_2$ pipeline has been proposed by the United Kingdom's National Grid as a means of providing the region's concentration of $CO_2$ emitters (including the White Rose project) with access to a high concentration of large storage sites (Zero Emissions Platform, 2014). Element Energy Limited has suggested a Scotland and Central North Sea CCS Hub that could incorporate $CO_2$ from a project at the Peterhead Power Station and/or the St. Fergus gas terminal (Element Energy Limited, 2014).

3.3.1.1.5 Collie–South West $CO_2$ Geosequestration Hub

This hub is in the preparation phase. The Western Australian Department of Mines and Petroleum will lead a government–industry partnership that includes a consortium of major industrial emitters in Western Australia (Government of Western Australia, 2012). $CO_2$ from area utilities and industries is expected to total 5–6 Mtonnes/yr. The hub will be located where the proposed Kwinana and Collie pipelines meet at the injection site between Bunbury and Wagerup.

*3.3.1.2 Pipeline Networks*

Pipeline networks can be used to transport the $CO_2$ from the sources to the storage sites. The basic components of a network are nodes and links (Denning, 2004). Nodes represent source and destination points or clusters, while links connect pairs of nodes and represent the relationship between them. A network usually consists of the transmission (primary) network and the distribution (secondary) network (Kabirian and Hemmati, 2007). The transmission network includes the nodes and the trunk lines between the nodes. The distribution network includes the branch lines that radiate from a node to the individual sources and destinations. The properties of the links (e.g., the length and delivery rate) are determined by the characteristics of the nodes that they connect.

Networks can also be useful as a means to control the flow in a pipeline or set of pipelines. Pipelines can be dedicated, linking a specific $CO_2$ source with a particular geologic sink. These pipelines have more leeway in terms of impurities because only one sink's requirements must be satisfied rather than having to meet a set of common guidelines that fulfills the most stringent requirements of one of several storage sinks. Other approaches offer more flexibility in terms of mass flow rate and increase in complexity as $CO_2$ sources and geologic sinks are added. These approaches include few sources to few sinks, few large sources to many smaller sinks, many smaller sources to few larger sinks, and many sources to many sinks. The "many sources" approaches offer the most options to control the flow in a pipeline system, especially when the sources are of various types. When some of the sources are down for routine maintenance, it is likely that others will still be producing $CO_2$.

##### 3.3.1.2.1 Process Control Objectives

The starting point of developing control strategies for pipeline networks is definition of the control objectives. Irrespective of fluid being transported, pipelines share similar objectives, such as:

- Satisfaction of sources' transport requirements.
- Satisfaction of the end users' (i.e., sinks') delivery requirements, including metering to allocate and account for supply and distribution of the fluid.
- Safe operation of all portions of the pipeline within design parameters.
- Identification and effective response to pipeline leaks, ruptures, or other losses in a timely manner.
- Efficient operation of the pipeline while minimizing wear of pipeline components.

The physical and chemical properties of captured $CO_2$ introduce control objectives that are different from the control objectives for other fluids. These different objectives include:

- Maintenance of a single, subcooled liquid- or a supercritical phase along the pipeline to minimize pressure drop.
- Understanding that captured $CO_2$ contains numerous impurities in varying concentrations that are often dependent upon the technology employed to capture the

$CO_2$. These impurities should be minimized to avoid effects ranging from metal deterioration or damage from corrosion or low temperatures to changes in thermodynamic properties that can increase compression requirements.

- Avoidance of rapid valve closure, blowdown valve opening, pump shutdown, pressure release, and other actions that could lead to pressure surges, the "slinky effect" (which is similar to water hammer), cyclic pressure variations, formation of solids, and cooling of the pipe.

- Pipeline control requires an ability to manage both the volumes received from sources and delivered to sinks and the characteristics of the components and resources that are available to the system. The strategy for doing this in the most efficient manner becomes more difficult as the ability to control the $CO_2$ coming from sources or being taken up by sinks decreases. Access to additional resources, such as temporary storage, can be helpful as components of the control strategy.

Coordination among those operating sources, sinks, and temporary storage will be critical and will need to include both forecasted as well as current operations. Pipelines connecting single sources to single sinks will be tightly coupled; excess $CO_2$ production will need to be vented to the atmosphere, while insufficient $CO_2$ production will require adjustment by sinks. Coordination must ensure the flexibility that sources and sinks will require to be able to deal with constraints such as minimum or maximum pipeline pressures and flows or pipeline packing and temporary storage constraints. The opportunity for one source to operate its capture unit more severely to produce more $CO_2$ than would be typical in order to compensate for another source's reduced rate or a sink's increased demand is an example of such coordination. Another example of coordination, this one involving changes at an EOR field, would be a switch to WAG or shutting in a well to reduce its $CO_2$ demand in order to compensate for reduced supply or increased demand for $CO_2$.

Coordination might be complicated by differences in the economic situations of participants on the pipeline network. A source that owns cheaper carbon credits and is operating near its maximum capture rate will be less motivated to increase its $CO_2$ flow rate into a pipeline than one with more expensive credits operating nearer its minimum capture rate. However, as in the case of U.S. electricity generation and natural gas network operation in the United Kingdom, $CO_2$ pricing can be used as a coordinating mechanism.

Table 25 categorizes the controllability of several types of CCS system components. Individual natural sources contain predictable levels of impurities and are drawn off at a rate needed by the end user(s). They are therefore very controllable. In contrast, anthropogenic sources will likely contain impurities of some type and are produced at a rate that is less easily controlled unless it is possible to vent to the atmosphere should more $CO_2$ be produced than can be taken up by the geologic sink(s) at a given time. In terms of storage, EOR activities can be reasonably controlled by producing fluids to manage geologic formation pressure, employing $CO_2$ recycle (injecting $CO_2$ that is produced with the oil with $CO_2$ from the pipeline), making use of WAG injection, and by using multiple, redundant wellbores (potentially tens or hundreds of

**Table 25. Categories of Representative System Components**

| Substantial Controllability | Limited Controllability |
|---|---|
| *Natural Sources and Sinks* | *Industrial/commercial sources and sinks* |
| Geologic $CO_2$ Sources | Anthropogenic sources |
| Enhanced Oil Recovery Operations | Enhanced coalbed methane operations |
| Geologic $CO_2$ Sinks | |
| Atmospheric Sink (i.e., venting) | |
| *Partially Filled Storage* | *Storage at an extreme* |
| Half-Filled Storage | Empty or full temporary storage |
| "Half-Packed" Pipeline | "Unpacked" or "packed" pipeline |

wells compared to just a few for geologic storage in a saline formation). Fluid production from the reservoir and the use of multiple, redundant wellbores are approaches that could be applied to geologic storage in a saline formation or depleted reservoir to provide additional flexibility and adaptability when the $CO_2$ supply is variable.

An example of a situation that would present a significant control challenge would be a single fossil fuel-fired power plant that could experience substantial penalties for emitting $CO_2$ to the atmosphere connected to a single geologic sink through a constrained pipeline. The $CO_2$ source in this instance would be subject to daily and seasonal variation as well as variation caused by compensating for intermittent renewable electricity generation. Such variation could be attenuated by ensuring adequate pipeline capacity and then introducing additional sources and sinks that can compensate for the variation as well as strategically using temporary storage.

Another example of the importance of adding geologic storage sites to a pipeline network is the fact that most $CO_2$ storage through EOR occurs within the first few years of injection. The $CO_2$ storage rate will decrease significantly with time at a given site. The application of $CO_2$ EOR as a $CO_2$ storage mechanism will eventually require compensation for a relatively "constant" $CO_2$ supply from the industrial sources. In the future, new oil fields or development phases may need to be added or combined with geologic storage in saline reservoirs to keep up with the $CO_2$ supply.

3.3.1.2.2 Temporary Storage

The introduction of strategically placed temporary storage into a pipeline network can help to attenuate variation. There are different types of temporary storage, ranging from pipeline "packing" (varying the pipeline pressure to "pack" more or less $CO_2$ into the pipeline, which has, in essence, become a storage vessel) (Det Norske Veritas, 2010), to temporary storage in a capture sorbent or solvent, to temporary storage in structures such as fabricated storage vessels or underground storage such as depleted reservoirs, brine aquifers, and salt caverns. The effectiveness of temporary storage is enhanced when source production and sink delivery rates can be varied to meet the needs of current or predicted conditions and when the pipeline is not constrained. While oversizing capture and transport equipment or operating them more severely than is necessary is financially undesirable, such actions can reduce system variation. For example, temporarily increasing the capture rate in order to fill temporary storage in anticipation of a period of reduced capture because of plant maintenance requires that the capture plant and pipeline be somewhat oversized and that temporary storage be constructed; all of which increase capital cost. However, a more consistent source increases the value of the $CO_2$ to EOR operators, which could increase the price that these $CO_2$ consumers would be willing to pay. Such oversizing would also permit capture of an amount of $CO_2$ that would offset the increased emissions that might occur during maintenance.

The capture strategy employed by sources can affect the capacity requirements of temporary storage. In situations in which sink rates are constant and capture rates can exceed delivery rates, a simple strategy in which capture rate varies with emission rate to maintain a constant capture fraction has been shown to possess larger storage requirements than approaches that vary capture fractions by capturing larger fractions when rates are lower (Schlasner and others, in preparation).

#### *3.3.1.3 Economic Factors and Control Strategies*

Control strategy can be complicated by economic factors. For example, if $CO_2$ is captured from an anthropogenic source because of economic penalties for emission of the $CO_2$, and the $CO_2$ is sent to a saline formation for permanent storage, the only economic factor is associated with the source. Should the $CO_2$ be sent to an oil field for EOR purposes, then an additional economic factor comes into play: maximization of the oil production revenue. It is important for all of the economic factors to be considered when developing a CCS network control strategy. There is currently a significant shortage of $CO_2$ for EOR operations in the United States (Melzer, 2012). This paradigm may shift as $CO_2$ capture is implemented at the industrial or utility scale.

#### *3.3.1.4 Components of a Pipeline Control System*

The components of a pipeline control system include various sensors for flow, pressure, and temperature (and, perhaps, composition); actuators (such as valves); and remote terminal units (RTUs) that communicate locally with the sensors and actuators as well as with the master, supervisory control and data acquisition (SCADA) system located at a distance. The SCADA system collects, processes, and displays pipeline information to persons who operate the pipeline from a central control room. These persons, through the SCADA system, transmit commands back to the RTUs that operate the actuators.

Beyond its ability to receive pipeline information and transmit actions that provide basic control functionality, the SCADA system's processing capability is crucial to providing the monitoring necessary to enable compliance with the control objectives. The SCADA system provides:

- An estimate of the physical state of fluid along the pipeline so that a single phase can be maintained and pressure drop minimized.
- Timely identification of leaks, ruptures, or other losses.
- A material balance estimate to assist with the balance of receipt and delivery of $CO_2$.

- An estimate of the volume of $CO_2$ that could be accepted or delivered before the maximum allowed operating pressure or minimum single-phase pressure is exceeded. The volume accepted by the pipeline system could be changed by increasing line packing and/or the amount in temporary storage. The amount to be delivered can be increased by decreasing line packing and/or the amount in temporary storage.

- Projections of effects of potential changes on the pipeline's state and performance in receipts and deliveries.

- Monitoring of impurity concentrations along the pipeline. While this may not be necessary if the pipeline serves a single source to a single geologic sink, it is important in a pipeline network situation to verify that the $CO_2$ stream quality meets the expected standards as well as to understand which of multiple sources may have contributed particular impurities.

- Projection of the effect of receipt of "off-spec" $CO_2$ on fluid properties and pipeline performance.

- Projections of conditions at the site of a leak or rupture at a point in the pipeline.

- The key to accurate monitoring and response is accurate property data and equations of state for the range of conditions at which the pipeline will operate. These may be represented in a thermohydraulic model of the process that has been empirically validated. Computational pipeline monitoring (CPM) is a widely used technique for leak detection. Four major approaches to CPM include flow (or pressure) change, mass (or volume) balance, dynamic modeling, and pressure point analysis. Statistical methods are sometimes applied to validate flow balances (Det Norske Veritas, 2010). The pipeline associated with the Weyburn project employs a leak detection system that scans once every five seconds (IEA Greenhouse Gas R&D Programme, 2014).

### *3.3.2 Parameters That Affect Capital, Operating, and Maintenance Expenses of $CO_2$ Pipelines*

The physical and chemical properties of "captured-quality" $CO_2$ differentiate it from other gases that are transported by pipeline, creating potential issues for its pipeline transport, including:

- Accelerated pipe corrosion due to the presence of wet acid gases.

- Formation and accumulation of liquids or solids during depressurization.

- Rapid expansion of previously formed liquids or solids because of vaporization or sublimation.

- Degradation of pipeline components because of materials incompatibility, such as supercritical $CO_2$ attack on some polymeric, elastomeric, or other organic seals.

- Low-temperature, ductile–brittle transitional metal fracture during depressurization, such as operational depressurization of blowdown assemblies.

- Enhanced fracture propagation due to $CO_2$'s decompression characteristics (Cosham and Eiber, 2008; Mahgerefteh and Brown, 2011).

- Debonding and detachment of internal coatings caused by $CO_2$ permeation or solvent action.

- Variation in fluid properties because the levels of impurities vary.

Examples of problems resulting from these types of issues include seal failure because of abrasion by dry ice particles and/or by solvent attack by supercritical $CO_2$, metal wear caused by the low viscosity and lubricity of $CO_2$, and lubricant breakdown by $CO_2$ (Adams, 2011; Moore, 2011). Another potential problem involves the possible destruction of the elastomers in pipeline pigs when rapidly depressurized because of expansion of absorbed $CO_2$ (Adams, 2011), although other researchers have noted that in-line inspection of $CO_2$ pipelines (i.e., using pipeline pigs) is possible (Tiratsoo, 2011).

M. Rhoades of Kinder Morgan (2011) listed the attributes of $CO_2$ that make it different from other pipelined gases:

- Having a high density.

- Being temperature-sensitive relative to load changes and acoustic resonance.

- Exhibiting nonstandard behavior related to potential phase change and performance calculations.

- Possessing compatibility issues related to lubrication, dehydration, corrosion, and explosive decompression.

These differences, then, were manifest by issues such as increased pulsation and vibration in reciprocating compressors, decreased valve and passage efficiency, and downstream plugging caused by material compatibility issues between $CO_2$ and lubricant and seals. Prior to their resolution, these issues introduced increased costs in the form of increased unscheduled maintenance and inefficient operation (Rhoades, 2011). Today, Kinder Morgan, Denbury, Sulzer Pumps, and others have expressed confidence that they have adequately addressed these issues. They make use of compatible materials such as 90-durometer peroxide-cured butadiene–acrylonitrile copolymer, urethane and Teflon materials, and mineral and synthetic oils for lubricants. Equipment has been redesigned to incorporate larger cylinders and valves; longer stroke lengths with improved rod load management for positive displacement compressors; and gas seals along with nongalling metals, carbon, or polyether ether ketone wear parts for centrifugal pumps. Foundation and support design have been improved to include heavier skids and foundations, increased off-skid clamping, and stress-free installations. Finally, they have increased maintenance monitoring, among other actions (Moore, 2011; Rhoades, 2011; Adams, 2011). This confidence even extends to pipeline inspection, which had been troubled by instances such as the $CO_2$ damage to pipeline pigs that was mentioned previously. ILI techniques for both vapor and dense phase are now available from at least three commercial service companies (Tiratsoo, 2011).

The incorporation of resistant materials, adoption of increased equipment and pipeline monitoring, and installation of additional structures and supports have reduced unscheduled maintenance and improved operational efficiency. Unfortunately, these improvements have also increased capital and operating expenses when compared with baseline natural gas pipelines. The additional costs have not been found in any of the literature reviewed by this investigation. In light of the limited information available regarding the incremental costs of installing $CO_2$ versus other gas pipelines, it is not surprising that information describing the incremental cost due to $CO_2$ variability also is unavailable.

Another approach to estimating the cost of $CO_2$ variability would be to consider it in terms of the incremental cost of variability on natural gas pipeline construction and operation. Compared with most existing $CO_2$ pipeline operations, which run as consistently as practical, the U.S. natural gas pipeline system varies on seasonal, daily, and even hourly bases to meet customer demand. Seasonal variation is satisfied though the introduction of large temporary storage facilities, typically underground reservoirs and caverns, such as depleted oil and natural gas reservoirs, brine aquifers, and salt caverns. As Tables 26 and 27 indicate, each type of storage has distinct characteristics regarding how much of its capacity is available for delivery, the frequency with which it is cycled, and its costs.

Much of the short-term (i.e., daily and hourly) natural gas demand variation is accommodated by drawing from aboveground liquefied natural gas storage vessels or by intentionally varying pipeline operation by increasing and decreasing pressure so as to use the pipeline for temporary storage. The practice, termed “linepacking” or “packing,” increases the volume stored while “drafting” reduces the volume. These actions are well known and documented (U.S. Energy Information Administration, 2014c). For example, the U.S. Energy Information Administration provides a definition and description of such actions in an introductory overview of the U.S. natural gas pipeline system (U.S. Energy Information Administration, 2014a).

**Table 26. Characteristics of Types of Natural Gas Underground Storage Facilities (Federal Energy Regulatory Commission, 2004)**

| Type | Cushion Gas Fraction[a] of Total Gas Capacity | Injection Period (Days) | Withdrawal Period (Days) |
|---|---|---|---|
| Aquifer | 0.5–0.8 | 200–250 | 100–150 |
| Depleted Oil/Gas Reservoirs | 0.5 | 200–250 | 100–150 |
| Salt Caverns | 0.2–0.3 | 20–40 | 10–20 |

[a] “Cushion gas fraction” is the ratio of the volume of gas that is required to remain in storage to support normal operation to the total volume of gas that can be held in storage during normal operation; the difference between the total and cushion volumes is the working gas volume that can be withdrawn during normal operation.

**Table 27. Development Cost of Natural Gas Storage (Federal Energy Regulatory Commission, 2004)**

| Type | Development Cost (2004 US$ per billion cubic feet of working gas) |
|---|---|
| Two-Cycle Reservoir | 5–6 million |
| 6–12-Cycle Salt Cavern | 10–12 million |
| Northeast and West | less than 25 million |

Unlike underground storage, estimates of the costs related to varying operations to support linepacking are not readily available. No information regarding additional capital, operating, or maintenance expenses related to varying pipeline operations has been found during this study. It is not known if the absence of information is caused by secrecy by pipeline operators or is instead the result of a lack of interest in studying the incremental cost of packing. It is interesting to note, however, that while reports of the incremental cost of packing natural gas pipelines have not been found during this study, the incremental value of packing and approaches to acquiring that value are prevalent in the literature. For example, Ríos-Mercado and Borraz-Sánchez (2012) surveyed the literature with regard to several optimization problems including short-term-basis storage, pipeline resistance and gas quality satisfaction, and fuel cost minimization via pipeline transmission networks. Arvesen and others (2012) applied a Least Squares Monte Carlo algorithm to a model of a gas-fired power plant experiencing gas and electricity price volatility and concluded that the plant could increase the value of the pipeline gas by 34% if 10 hours of storage were available.

The lack of cost information related to variation of natural gas pipelines (other than the cost of developing and constructing underground storage, to which $CO_2$ temporary storage likely would be comparable) means that natural gas pipelines provide little insight into expenses related to varying $CO_2$ pipeline operation. Admittedly, given the different physical and chemical natures of natural gas and captured-quality $CO_2$, the accuracy of adopting the cost increment due to variation in natural gas pipelines as a surrogate for the cost increment caused by variation in $CO_2$ pipelines is uncertain. However, incremental natural gas pipeline costs could serve as a lower limit for expected incremental $CO_2$ pipeline costs. For example, the work required to restart the movement of fluid within a pipeline containing 200 tonne/km supercritical $CO_2$ after it was halted is significantly more than that required to restart a pipeline containing 50 tonne/km of 69-bar (1000-psi) natural gas.

# 4.0 OPERATIONAL FLEXIBILITY IN $CO_2$ STORAGE

## 4.1 Wellbore and Reservoir Considerations

A theoretical assessment of the effects of variable and intermittent flows of $CO_2$ on wellbore integrity and storage reservoirs in saline formations, depleted oil and gas fields, and EOR was conducted for this study. The assessment included a literature search, but no published papers were found that focus directly on the effects of intermittent $CO_2$ flows on wellbore integrity or reservoirs. Insight on the topic was gained from literature discussing the lessons learned during the performance of several recent and ongoing commercial-scale CCS projects as well as $CO_2$-based EOR operations. The literature search findings were supplemented with insight provided by interviews with engineers who have experience with both $CO_2$-based EOR operations and acid gas ($CO_2$ and $H_2S$) disposal operations.

For the purpose of this discussion, the geologic storage reservoir is considered to be operated as a single entity, whether it is defined as a single injection well or a field of multiple wells that are operated as a single unit with $CO_2$ being supplied by a single, main pipeline. This scenario is the most likely to experience problems related to intermittency because a system that includes multiple $CO_2$ source lines and/or multiple independently operating injection units probably would be able to manipulate transport and injection in such a way as to minimize or eliminate intermittency.

Potential issues of concern related to operational flexibility of $CO_2$ storage were identified, based on findings in the literature as well as from previous EERC experience with CCS projects. These issues are discussed in the following paragraphs.

One possible cause of intermittent $CO_2$ flow to an injection site is compressor downtime. This would result in an inconsistency in $CO_2$ phase behavior within the pipeline system. The maintenance of supercritical phase $CO_2$ in the pipeline is often a condition of the $CO_2$ purchase contract. In the event of compressor downtime, maintaining supercritical phase $CO_2$ in the pipeline may require that injection wells be shut in (i.e., stop operation). Shutting in injection wells outside the parameters of the designed injection scheme at an EOR field can result in deleterious changes in reservoir pressure and oil miscibility that can cause attendant drops in oil production. In some instances, this type of unplanned change in reservoir pressure can result in geochemical reactions (such as precipitation of minerals or asphaltenes) or change the fluid saturation properties (e.g., imbibition of water) of the rock. These phenomena can have long-term impacts on key reservoir characteristics such as injectivity and relative permeability. Fortunately, both the literature and the interviews with experts from both North America and Europe indicate that, as long as plans for intermittency are made in the early stages of a project, steps can be taken to manage and mitigate those impacts.

Initial interviews with $CO_2$ EOR operators indicated that cyclic, or otherwise intermittent, $CO_2$ supplies have historically been a nonfactor with respect to impacts on in-field distribution pipeline networks, wellbore integrity, or reservoir conditions. It is standard engineering practice to design and operate a $CO_2$ EOR operation in such a way as to avoid large-magnitude and/or high-frequency cycles in the $CO_2$ stream. $CO_2$ EOR projects are generally designed with a safety factor on both pressure and capacity that is significantly above operation pressure. They are also designed and built to allow for expansion and additional $CO_2$ capacity. EOR operations always include recycling of $CO_2$. As long as the potential for intermittency is factored into the design, and standard EOR engineering practice demands that it is, then the recycled $CO_2$ can be (and often is) managed in such a way as to mitigate the effects of intermittency in the primary $CO_2$ source line. As EOR operations expand and/or the longer they operate, the recycle volumes increase. An intermittent supply would theoretically have the highest impact near the beginning of a new EOR operation.

When wells are “shut in,” they are essentially stopping oil production, which can have a huge impact on the economics of an EOR project, ranging from tens of thousands to millions of dollars a day in lost production depending on the size of the field and the magnitude of variability. Not only do chokes and throttles need to be adjusted on a well-by-well basis, chemical treatments, water disposal, etc., also need to be adjusted. It is clear that variability does have a tangible impact on EOR operations, but the impact can be mitigated by flexible operation.

With respect to wellbore integrity, fatigue and corrosion are considered to be the most likely effects of intermittent flow. This is particularly true in wells that see the injection of mixed gas streams (e.g., $CO_2$ and $H_2S$) because changes in the pressure of the gas column in the wellbore caused by stopping injection can result in deleterious phase behavior, including segregation of the component gases. This can lead to issues when injection is started up again, including fatigue and corrosion of wellbore materials. The Joule-Thomson effect caused by pressure drop can also be extreme, leading to freeze-up of valves and joints, which in turn can also cause fatigue and corrosion of wellbore materials. Fortunately, the combination of knowledge of wellbore conditions (i.e., temperature, pressure, chemistry of the wellbore materials and injectate) that is mandated by regulations and the application of wellbore modeling prior to the start of injection can be used to identify the correct operating conditions. Using standard oil and gas engineering protocols, the potential for intermittency is factored into the design of the operating conditions. Contingency plans are developed accordingly and implemented if necessary.

Many of the approaches taken to mitigate the effects of supply intermittency to wellbores and reservoirs in EOR fields rely heavily on the recycled $CO_2$ stream that becomes available to the operator early in the operational lifetime of the EOR project. At first glance, this may suggest that CCS operations in saline formations may be more prone to suffer consequences from intermittent supplies. However, there are two factors that suggest that this may not be the case. First, storage in saline formations at many locations may require the use of water production wells to control $CO_2$ plume geometry and pressure front movement, in which case solutions developed for the EOR industry that include the use of recycled $CO_2$ to mitigate supply intermittency will likely apply. If intermittency is expected to occur frequently and/or vary widely, it might be prudent to include water production wells in the project design specifically for the purpose of mitigating that intermittency. Secondly, because of their lack of hydrocarbons and, therefore, lack of historical fluid withdrawal as part of production operations, saline formation reservoirs are likely to exhibit initial reservoir pressures that are higher than those in oil and gas reservoirs. The higher reservoir pressures will help to maintain higher wellbore pressures, thereby aiding in the mitigation of the effects of intermittent flow. In this scenario, the largest impact would be at the start-up of operations. Once established and operating, a project can be more adaptive. Operators historically have proven to be able to adapt to variability.

Other mechanisms by which injectivity can be diminished or project infrastructure can be damaged as a result of pressure and temperature changes related to intermittent $CO_2$ supplies were identified in the literature, with hydrate formation and salt precipitation having the greatest impact. Gas hydrates are cage-like, crystalline lattices of water (clathrates) containing methane. Hydrate formation may be the most dramatic consequence of flow interruption as it can cause both diminished injectivity and rapid corrosion. However, hydrate formation is reasonably predictable given an understanding of the pressure and temperature regimes existing in the system as well as the water fraction of the injectate stream. Hydrate formation is also generally preventable using multistage compression and knockout systems as well as MEG.

Salt precipitation (and perhaps asphaltenes, paraffins, and calcite precipitation) could feasibly be exacerbated by intermittent dry $CO_2$ flow, if the pressure regime is favorable. The first wave of $CO_2$ dries the reservoir, causing precipitation preferentially in the near-wellbore environment. When injection stops (assuming that the pressure differential is low), some fluid will flow back toward the wellbore, carrying additional salt. If repeated, this cycle might lead to additional preferential precipitation in the near-wellbore environment. As with the other considerations that have been described, prior knowledge of the reservoir characteristics and injectate composition can be applied using standard engineering principles to design and operate injection schemes that minimize the negative effects of $CO_2$ supply intermittency.

### 4.2 Effects of $CO_2$ Stream Impurities on Geologic Storage

Impurities in a $CO_2$ stream may need to be removed for HSE protection reasons but it is also important for the effective transport and storage of the $CO_2$ stream. The possible impacts of impurities on geologic storage are reservoir-specific and depend on both the mineralogical composition and the type and amount of impurity. The impacts can vary from slight dissolution that creates microvoids to mineralization that fills the pore space (Mikunda, 2012).

The European Union Directive on the geological storage of $CO_2$ defines the $CO_2$ stream as consisting overwhelmingly of $CO_2$ and that it should not be a carrier by which to dispose of waste or other matter. The directive does allow for incidental substances that are at levels too low to adversely affect either the storage site or the transport infrastructure or pose a significant risk to the environment or human health (Mikunda, 2012).

Noncondensable impurities in a $CO_2$ stream reduce the density of the gas stream, which leads to a drop in the total storage capacity of a reservoir. Less-pure $CO_2$ would fill storage sites up more quickly, incurring higher injection and storage costs. Geochemical reaction between the $CO_2$ stream and in situ brine and minerals in the storage formation can reduce permeability and increase pore pressures in a geologic storage site. Fractures and pore spaces can be blocked by mineral precipitation. The geometry of the hydraulic capillaries can be altered by the growth in secondary minerals in the brine that result from the precipitation process (Mikunda, 2012). The formation of stronger acids due to the presence of water and $SO_2$ or $H_2S$ can reduce the pH of the formation water, forming a highly acidified zone in which rapid mineral dissolution of carbonate and silicate minerals may actually increase the porosity. However, at the edge of the injection zone, the increase in pH actually results in the precipitation of secondary minerals, which can reduce the porosity and, potentially, the formation permeability.

### 4.3 Variable $CO_2$ Flows and Induced Seismicity

Concerns have appeared regarding the potential of subsurface injection of $CO_2$ to induce seismicity. The term "seismicity" is often associated with earthquakes, but the literature indicates that injection activities are more likely to cause microseismic events. Therefore, it is important to understand the distinction between microseismic events and earthquakes. A conventional earthquake involves slip along a fault in the earth's crust after pressure buildup over time exceeds the coefficient of friction along the fault. To be felt, a conventional earthquake must have a Richter magnitude of 3 or more, which would have a ground motion of about a millimeter at a location 100 km distant from the epicenter. The slip along the fault of a magnitude 3 event would be about 1 centimeter along a fault patch a few hundred meters in length. A microseismic event is analogous to a conventional earthquake except that it is very small, very localized, and has a magnitude so small it cannot be felt except by very sensitive instrumentation. Microseismic events have slip of 0.1 mm or less along a fault patch of one to a few tens of meters in length. The amount of energy released by a small microseismic event is sometimes compared to dropping a gallon of milk on the floor.

Every point in the subsurface is under a state of stress, from the weight of the overburden above it as well as from horizontal stresses due to regional tectonic forces in the earth. Changes in the local stress field due to manmade causes are possible, such as the injection of fluid into a geologic formation under pressure or the accumulation of water on the surface due to a dam. The opposite type of activity (e.g., draining fluid during oil production or removal of overburden by mining) can also change the local stress field.

Questions have been raised concerning the relationship between activities such as wastewater disposal, hydraulic fracturing of tight oil and gas formations, and $CO_2$ injection and seismicity. A study of increased seismicity in Oklahoma since 2008 asserted that the 2011 moment magnitude ($M_w$) 5.7 earthquake near Prague, Oklahoma, was likely induced by wastewater injection (Keranen and others, 2014). A study of injection-induced events by Ellsworth (2013) stated that hydraulic fracturing intentionally induces numerous microseismic events, the vast majority with $M_w < 1$. (Microseismic events are small events with $M_w < 2$ that can only be detected by instruments.) Recent IEA Greenhouse Gas R&D Programme (2013b) and U.S. National Research Council (2013) studies have investigated in detail concerns regarding the implications of $CO_2$ storage and the use of $CO_2$ in EOR with respect to inducing seismic events that can be felt. A range of factors are probably responsible for the number, locations, and magnitudes of induced microseismic events. These factors include the injection rate, total injected fluid volume, reservoir permeability, and the proximity of preexisting faults (Gerstenberger and others, 2012). Increases in both injection rates and total injected fluid volume, for example, typically raise reservoir pressures. This in turn increases the likelihood of elevated seismicity rates and the maximum magnitudes of any induced seismic events. Some of these factors are controllable, as injection rate and total injected fluid volume are usually operational choices. Reservoir permeability and the lack of proximity to known faults are typically criteria for site selection. Even so, some large-magnitude induced seismic events have occurred where previously unknown faults existed and were reactivated. With good characterization of $CO_2$ storage sites, a thorough site risk assessment, and appropriate pressure management, the occurrence of large seismic events can be minimized.

The range of opinions of investigators regarding the viability of large-scale $CO_2$ storage—from “feasible” when risk management and mitigation programs are included (Gerstenberger and others, 2012) to “likely unsuccessful” (Zoback and Gorelick, 2012)—provides insight into the limited knowledge about the relationship between $CO_2$ injection and induced seismicity. Analyses of specific $CO_2$ storage and EOR projects have provided some lessons learned:

- Upon reviewing 5 years of passive seismic monitoring data from the **Weyburn** project, Verdon and others (2010) found that microseimicity rates correlated with periods of elevated $CO_2$ injection rates as well as with changes in production activities in nearby wells. The distribution of injection-related event locations also appeared to correlate with the regions of $CO_2$ saturation that were identified using 4-D seismic analysis. In particular, they noted that a period of substantially elevated microseismic events during July and early August 2004 immediately followed a period of high injection that took place from May to July 2004. Pressure reduction near the producer wells was thought to have caused most events. Pressure reduction decreased stress above the well so that rock beside the well took up the load. The adjustment caused microseismic events.

- In a 2012 National Research Council report (National Research Council, 2012) the Midwest Geological Sequestration Consortium (MGSC) noted that the potential for inducing seismic events will likely be minimized if CCS does not significantly increase pore pressure above its original value. A thick reservoir having a high storage capacity and good permeability would help to minimize pore pressure increases, which is the type of reservoir represented by the Mt. Simon Sandstone and the **Illinois Basin–Decatur Project**. The potential for microseismic events is related to the maximum induced pore pressure, which dissipates rapidly with increased permeability. At a depth of 2134 m (7000 ft), the Mt. Simon Sandstone has excellent permeability, which works to reduce the risk of microseismic activity at the Decatur site (Midwest Geological Sequestration Consortium, 2011c). A presentation describing findings from microseismic monitoring of the Decatur injection site noted that microseismic activity appears to be clustered and evenly distributed among three preexisting planes in the lower Mt. Simon Sandstone and Pre-Mt. Simon units and the Precambrian basement. The microseismic activity seems to be associated with pressure perturbations in the three units and disruptions to injection operations often leads to increased microseismic event rates (Coueslan and others, 2013).

- The susceptibility of the **Sleipner** gas field's Utsira Formation was evaluated with respect to microseismicity. Fabriol (2001) concluded that the porosity values at Sleipner made microseismic events unlikely to occur in the Utsira Formation, except in shale lenses or at the top of the formation. This was later confirmed when Zoback and Gorelick (2012) noted that approximately 1 million tonnes of $CO_2$ had been injected over each of the past 15 yr without triggering seismicity. Assuming that the storage target is isolated from the near surface, injection into highly porous and permeable reservoirs that are laterally extensive would result in only small increases in pressure. Weak, poorly cemented sandstones such as are found in the formation would be expected to deform slowly in response to applied geologic forces. In this type of reservoir, the stresses relax over time, and the formations are not prone to faulting. Because of all of these traits, the Utsira Formation is ideal for $CO_2$ sequestration. It is isolated from vertical migration by impermeable shale formations and it is highly porous, permeable, laterally extensive, and weakly cemented (Zoback and Gorelick, 2012).

- Kuehn and others (2013) analyzed microseismic data from a pilot installation at Krechba, Algeria, operated by **In Salah** JV. They observed that over the period between August 2009 and June 2011 over 5000 microseismic events were detected. Because of a high correlation between the occurrence of microseismic events and injection rate at well KB502, they concluded that the majority of the microseismic activity was related to the $CO_2$ injection at KB502. A geomechanical analysis suggested that the fracture pressure was temporarily exceeded, fracturing the reservoir during two periods in 2010 and increasing microseismic activity.

- McGarr (2012) reviewed numerous case histories of earthquakes induced by injection activities, including wastewater disposal at depth and development of enhanced geothermal systems. It was observed that it may be feasible to estimate bounds on maximum [seismic moment] magnitudes based on the volume of injected liquid. The total volume of injected fluid appears to be linearly proportional to the maximum seismic moment, the upper bound is expected to increase with time as long as a given injection well remains active. However, neither injection rate nor wellhead injection pressure appears to influence maximum magnitude. While seismic outcome cannot be determined in advance of an injection project, it is encouraging that upper bounds on seismic moment show a reasonably well-defined linear dependence on total volume of injected fluid.

The open literature suggests that a variety of factors related to $CO_2$ injection (injection rate, wellhead injection pressure, total injected fluid volume, reservoir permeability and proximity to preexisting faults) might contribute to increased seismicity. Studies disagree as to the relative importance of these factors, although they appear to agree that the current state of knowledge has limited ability to predict seismicity, partly because the geomechanical and hydrological factors that control the seismic response to injection are poorly understood (McGarr, 2012). Despite an observation by Coueslan and others (2013) that disruptions to injection operations often lead to increased microseismic event rates, it appears that, unless variability produces excessive rates, pressures, volumes, or other conditions, the effect of $CO_2$ variability upon seismicity is too subtle for the current state of knowledge to identify or predict.

## 5.0 REAL-WORLD EXPERIENCE

Experts in EOR who were interviewed for this indicated that anthropogenic $CO_2$ sources are more variable in both rate and composition than naturally sourced $CO_2$ and as such require additional operational considerations compared to fields supplied from natural $CO_2$ sources where supply can be designed to match demand. Mechanical issues and maintenance on the capture, processing, and compression facilities contribute substantially to both planned and unplanned supply variability of anthropogenic $CO_2$ sources. Short-term variability/intermittency and out-of-spec composition can typically be managed with minimal modification to field operation at the sink but an extended shortage or out-of-spec composition of $CO_2$ requires modifications to operations. The amount of $CO_2$ sent to individual wells typically is adjusted based on performance and pattern analysis at the field. It may be necessary to curtail $CO_2$ injection at one or more wells. In some cases, production wells may need to be shut in to maintain reservoir pressure above a certain minimum threshold to minimize impact to long-term flood performance. Pipeline packing is used to hedge against unexpected (or sometimes even expected) short-term variability in supply.

Whether or not the operators of the sink know about impending $CO_2$ variability depends on if the outage is planned (as for maintenance). Issues such as compressor failures or other mechanical problems at the $CO_2$ source may not allow even a 24-hour notification. The length of a $CO_2$ outage is more detrimental to operations than the magnitude of the outage, particularly for meeting production forecasts.

Certain components of the $CO_2$ stream composition are continually monitored on the supply line prior to the $CO_2$ passing into the pipeline and to the EOR field. If these components are out of specification for a significant length of time, the supplier will vent the $CO_2$. Both the $CO_2$ supplier and the field can vent, if necessary. There are limitations as to how much $CO_2$ can be vented without penalty. The volume and composition of the vented $CO_2$ are reported as required by local departments of environmental quality.

The addition of $CO_2$ from a different source type to a pipeline would be of concern only in that the composition be measured to be sure that it meets the pipeline and EOR or storage field specifications. Any change in composition would need to be evaluated to ensure that there will be no effect on pipeline materials or an adverse reaction with the reservoir. For example, carbonyl sulfide can impact EOR operations.

One of the primary concerns relative to variability of $CO_2$ flow rate or stream composition in an EOR field is the impact it may have on pattern response, or a loss of pattern response caused by intermittent injection, both of which have a direct impact on profitability and meeting performance forecasts. If an EOR field does not receive the $CO_2$ supply that is budgeted, it directly affects production and may impact the economic driver for capture/storage. More injection wells and a larger volume of recycle can help to mitigate the impact of variable or intermittent supply. This is why supply consistency concerns may be reduced as injection programs expand. Having multiple sources can also reduce the magnitude of variability in $CO_2$ supply.

Considerable automation is used in EOR fields to monitor pressure, flow rates, wellhead chokes, emergency shut-in, and the like. On the supply side, automation is used to monitor the stream for contaminants. Automation helps to reduce operator error because systems can be monitored from a remote control room. It is viewed as a huge benefit, even though it can increase the cost of operations.

Assuring that the composition of a $CO_2$ stream is within specifications is the key to preventing deterioration and/or corrosion issues since the pipeline systems are designed to accommodate relatively slow, long-duration pressure swings that are experienced in large supply lines.

## 6.0 SIGNIFICANT FINDINGS

Experts interviewed in conjunction with this study expressed confidence that existing $CO_2$ pipeline networks can be operated safely and, at least in the case of U.S. EOR operations, economically. Such confidence is attributable to the demonstration of the feasibility of $CO_2$ transportation over many years by adopting significant safety margins in pipeline design, operation, monitoring, and inspection early in the development of this infrastructure.

If CCS is to be deployed on a wide scale, challenges that are related to variability of the $CO_2$ stream, either in composition or flow rate, should be expected. While it is not likely that $CO_2$ captured from an industrial or electric utility source would be consistent in flow rate and free of impurities, several examples show that it is possible to successfully transport and inject a variable $CO_2$ stream. Five full-scale, commercial transport–storage scenarios (Sleipner, Snøhvit, InSalah, Weyburn, and Decatur) have each experienced mass flow variability or interruption in flow. In each case, pipeline and injection engineers were able to accommodate any issues that arose. Proper engineering and operational contingency planning have allowed these and other projects to mitigate the negative effects of significant variability in composition.

Literature survey performed for this study found that other researchers' models indicate that impurities in the $CO_2$ stream could affect the pipeline through increased corrosion, difficulty in attaining or maintaining the supercritical phase during transport, potential increase in pipeline fracture propagation, and changes in $CO_2$ stream thermodynamic properties.

Challenges for the injection and storage of the $CO_2$ include hydrate formation, which may be the most dramatic consequence of flow interruption as it can cause both diminished injectivity and rapid corrosion and salt precipitation, which could feasibly be exacerbated by intermittent dry $CO_2$ flow. Another risk of intermittent injection is the unintended introduction of geomechanical fatigue (given high enough frequency).

The almost inevitable changes in pressure within pipelines, wells, and equipment that are likely to accompany variability or interruptions in flow have the potential to cause unintended multiphase flow and unanticipated corrosion properties. However, the EOR industry, in the United States has proven that it is possible to adapt to variability and intermittency in $CO_2$ supply, even though EOR operators would prefer to have a constant supply of $CO_2$ for which they can design and optimize their systems. This is evident by preferred rates for consistent or uninterruptible supply. The use of multiple wells will be crucial to successful injection at a storage site, particularly for pressure control, water disposal, to reduce project liability, and to enable the operator to adapt to variability in $CO_2$ supply. Projects will be most susceptible early in their lifetime to adverse impacts to operations caused by variable/intermittent $CO_2$ supply.

The confidence expressed by experts has permitted operators to move beyond demonstrating feasibility to optimization of their operations through careful reduction of those margins as justified by experience. An indication of this is the Cortez $CO_2$ pipeline, which was built with a $CO_2$ carrying capacity of 19.2 Mtonnes/yr to 76.8 Mtonnes/yr (1 to 4 Bcfd) (Kinder Morgan, 2013). The pipeline was operated at a maximum capacity of 21.1 Mtonne $CO_2$/yr until

2008, when it was expanded to 25 Mtonnes $CO_2$/yr. It is being further expanded to 38.4 Mtonnes $CO_2$/yr by the end of 2016 (Wuerth, 2014).

Such $CO_2$ pipeline experience represents knowledge that can be applied in future CCS projects. The introduction of multiple anthropogenic sources that vary in $CO_2$ composition and possess the potential to introduce contaminants into pipelines during capture plant upsets, coupled with the removal of stabilizing sources and sinks and the imposition of severe penalties or constraints on venting move pipeline operation into regimes that are not well understood. It would be beneficial to slowly introduce anthropogenic sources and variable sinks into stable, existing networks and to carefully monitor and constrain their behavior until knowledge and confidence are acquired. At that point, constraints can be relaxed and projects optimized to achieve better economics.

## 7.0 GAPS IN KNOWLEDGE, IDENTIFIED CHALLENGES, AND PROPOSED TOPICS FOR FUTURE RESEARCH AND DEVELOPMENT

While researching the effects of variability of $CO_2$ stream on transport, injection, and storage during CCS activities, many gaps in knowledge were encountered. The following knowledge gaps have been prioritized by the authors of this report, with the relatively more important ones listed first.

- Experimental research is needed to validate the predictions of models, particularly with respect to the behavior of $CO_2$ containing impurities during transient conditions. More experience is required in order to understand the nature of the $CO_2$ flow, the range of slug speeds, and induced stresses on the pipeline.

- There is a need to better understand the fundamental properties of $CO_2$ mixtures with impurities and their impact on operation and costs associated with pipeline transport, injection, and storage.

- As conditions deviate from those of existing pipelines, it is important to be able to accurately predict thermodynamic and transport properties over the range of compositions and conditions of the fluid being transported. Models of such properties are critical to the accurate description of depressurization and other transient behavior. Experimental demonstration of the models' accuracy will be key to their acceptance by pipeline operators.

- There is a need for a recommended practice or guideline on transmission of supercritical $CO_2$ that incorporates all of the industry guidelines and standards. This could enable widespread deployment of CCS by ensuring that all pipelines will meet safety standards.

- Models that are accurate over a wider range of $CO_2$ compositions (and include $CO_2$-rich mixtures) and conditions than are typically encountered will be vital to expanding deployment of CCS. A precondition for such accuracy is equally accurate experimental data against which to validate property models.

- There is a need to understand the response of different types of reservoirs to intermittent $CO_2$ flow.

- There is need for an improved understanding of heat-transfer characteristics of $CO_2$ pipelines in different media, such as sea water, gravel and clay, and when ice-covered.

- There is a need for accurate prediction of:
  - Multiphase properties as well as of solid $CO_2$ and hydrate formation.
  - Improved modeling of captured-$CO_2$ fluid wave-propagation, flow-regime, and component-tracking between phases.
  - Noise generation and atmospheric dispersion prediction.
  - Metal crack propagation behavior.

- Experimental validation of custom and commercial software-based depressurization models (such as OLGA) would enable their application to real-world scenarios with confidence.

- Even though cost studies have been reported, accurate capital and operating cost information represent another knowledge gap, at least in regard to the open literature. This is especially true for situations that are inherently less predictable like variable anthropogenic sources linked to sinks possessing limited flexibility, such as a small number of EOR $CO_2$ injection wells with very limited opportunity to vent to the atmosphere. Stabilizing such situations could require inclusion of temporary storage into the pipeline.

Research has already begun in some of these topic areas. For example, Sintef reported results of a study of heat transfer characteristics of a pipeline for $CO_2$ transport in fresh water (Wilhelmsen and others, 2011) and work has been done to model thermodynamic and transport property models for CCS processes (Diamantonis and others, 2013). It is clear, however, that these knowledge gaps may benefit from (additional) future research and development. A better understanding of the thermodynamic behavior of $CO_2$ containing impurities under conditions ranging from "typical" to transient will allow wide-scale deployment of CCS.

## 8.0 SUMMARY

The extent of the technical challenges posed by the transport and storage of $CO_2$ from emission sources that do not produce a consistent $CO_2$ stream in terms of composition and/or mass flow rate was studied. An information review targeted what is known about the effects of variable $CO_2$ flow rate during pipeline transport of $CO_2$ in vapor and supercritical phases as well as its storage in deep saline formations, depleted oil and gas reservoirs, and during enhanced oil recovery (EOR) activities. The information review consisted of a literature search of publicly available information on the operational flexibility of existing $CO_2$ pipelines and geologic storage facilities as well as modeled scenarios. Telephone interviews supplied anecdotal information that augmented the information found during the literature search.

Five full-scale, commercial transport–storage scenarios (Sleipner, Snøhvit, In Salah, Weyburn, and Illinois Basin–Decatur) were reviewed to determine the extent of information that is available about the effects of $CO_2$ stream variability/intermittency of current CCS projects. The five projects have all experienced mass flow variability or an interruption in flow. In each case, pipeline and/or injection engineers were able to accommodate any issues that arose. Significant variability in composition has not been an issue at these five sites.

Different industrial processes produce $CO_2$ streams that have different compositions. The $CO_2$ capture method can also affect the composition of the $CO_2$ stream. Modeling results have indicated that the presence of certain impurities/quantities of impurities in the $CO_2$ stream may cause problems with maintenance of single-phase flow within the $CO_2$ pipeline. The presence of impurities changes the physical and transport properties of $CO_2$ by changing the critical temperature and pressure of the $CO_2$ stream, i.e., the conditions above which the stream must be maintained to remain in single-phase flow. Changes can also occur in the $CO_2$ stream hydraulics, which affects, therefore, the number of compressors and the power required for compression. Depending on their type and concentration, impurities can change other aspects of the pipeline such as fracture propagation, corrosion, nonmetallic component deterioration, the formation of hydrates and clathrates, and even the capacity of the pipeline itself. While $CO_2$ can be transported in a vapor phase, it is likely that the economics of most CCS projects will require that $CO_2$ be transported in its supercritical (i.e., dense) phase because vapor-phase transport would require considerably larger-diameter pipelines for the same mass flow rate and would experience high pressure drops. Vapor-phase transport is not used for pipelines that carry significant quantities of $CO_2$ and would require compression to overcome reservoir pressures if applied to geologic storage. Compression and transport of $CO_2$ for EOR purposes in the United States has shown that impurities are not likely to cause transport problems if $CO_2$ stream composition standards (such as the Dynamis $CO_2$ quality specifications or those developed by Kinder Morgan) are maintained and pressures are kept significantly over the critical point of $CO_2$ (i.e., kept at 10.3 MPa or higher).

The impurity with the most significant effect on transport and injection of $CO_2$ is water. $CO_2$ readily dissolves in water to form carbonic acid, which can corrode a pipeline at a rate of 1–2 mm within 2 weeks. Depending on its temperature, supercritical $CO_2$ can store several hundred ppm of water, which may form hydrates that can cause plugs that could clog the pipeline. Hydrate formation is dependent on the pressure, temperature, and water content of the $CO_2$.

Clearly, variations in the temperature and pressure within a $CO_2$ pipeline caused by variability in mass flow rate can have a substantial effect on corrosion and hydrate formation. Variability in mass flow rate can also cause issues with $CO_2$ pipeline operation that are exacerbated by temperature, pressure, and topography effects. Changes in mass flow rate can make it more difficult to maintain the temperature and pressure of the $CO_2$ stream within the designed pipeline operating conditions. However, $CO_2$ pipeline pressure control systems can be (and are) designed and operated in a manner that ensures maintenance of the operating conditions. When the topography changes significantly over the course of the pipeline route (such as up and down mountains and valleys), the $CO_2$ pressure can change, potentially forming two-phase flow with the supercritical phase pooling in the low spots. Two-phase flow lowers the bulk density of the fluid, which is very problematic for compressors and other transport equipment and adds to the cost to transport the $CO_2$. Two-phase flow seems to be more likely to occur when the pipeline is oversized relative to the amount of $CO_2$ that is transported.

Modeling/simulation and risk assessments that were researched provide little understanding or accurate forecasting of the specific effects of variable flow rates on pipeline health, safety, and environmental performance. However, safe operation of $CO_2$ pipelines begins with a pipeline design that establishes source compositions and conditions with an appropriate safety margin. Most (if not all) $CO_2$ pipelines in existence in North America are overdesigned for their current application; i.e., they are designed for higher flow rates and operating pressures through the use of thicker walls and/or larger diameters. For example, the Denbury Greencore Pipeline was designed to transport up to 13.9 Mtonnes/yr (725 MMcf/d) in the future, although initially only 0.96 Mtonnes/yr (50 MMcf/d) are being transported (Denbury, 2014).

Both temporary storage and $CO_2$ pipeline networks and hubs can be useful ways to control the flow in a pipeline or set of pipelines to minimize compositional and/or mass flow rate variations. Temporary storage can consist of fabricated or geologic storage or pipeline packing (varying the pipeline pressure to "pack" $CO_2$ into the pipeline, which has, in essence, become a storage vessel; packing offers more storage when pressures are lower). Networks can consist of a dedicated pipeline linking a single source to a single geologic sink, few sources to few sinks, few large sources to many smaller sinks, many smaller sources to few larger sinks, and many sources to many sinks. Dedicated pipelines have more leeway in terms of impurities because only one sink's requirements must be satisfied rather than having to meet a set of common guidelines that fulfill the most stringent requirements of one of several storage sinks. The "many sources" approaches offer the most options to control the flow in a pipeline system, especially when the sources are of various types. When some of the sources are down for routine maintenance, it is likely that others will still be producing $CO_2$. Many sources can also provide an averaging effect for the $CO_2$ stream composition, provided that all sources meet a minimum quality standard.

The impact of variable or intermittent flow of $CO_2$ on geologic storage was also studied. Intermittent $CO_2$ flow to an injection site such as for EOR could result in an inconsistency in $CO_2$ phase behavior within the pipeline system. The maintenance of supercritical-phase $CO_2$ in the pipeline is often a condition of a $CO_2$ purchase contract and maintaining supercritical-phase $CO_2$ in the pipeline may require that injection wells be shut in (i.e., operation stopped). Shutting in injection wells outside the parameters of the designed injection scheme at an EOR field can result in deleterious changes in reservoir pressure and oil miscibility that can cause attendant drops in oil production. In some instances, this type of unplanned change in reservoir pressure can result in geochemical reactions (such as precipitation of minerals or asphaltenes) or change the fluid saturation properties (e.g., imbibition of water) of the rock, if not properly managed. These phenomena can have long-term impacts on key reservoir characteristics such as injectivity and relative permeability. Fortunately, both the literature and the interviews indicate that, as long as plans for intermittency are made in the early stages of a project, steps can be taken to manage and mitigate the impacts.

Interviewed experts noted that cyclic, or otherwise intermittent, $CO_2$ supplies have historically not been a factor with respect to impacts on in-field distribution pipeline networks, wellbore integrity, or reservoir conditions. $CO_2$ EOR projects are generally designed with a safety factor on both pressure and capacity that is significantly above operation pressure. They are also designed and built to allow for expansion and additional $CO_2$ capacity. EOR operations always include recycling of $CO_2$. Recycled $CO_2$ can be (and often is) managed in such a way as to mitigate the effects of intermittency in the primary $CO_2$ source pipeline. Less recycle $CO_2$ is available when an EOR project first begins; therefore, more $CO_2$ is needed from the source pipeline. Intermittency of supply would be of more concern at that time. With respect to wellbore integrity and reservoir management, injection and production schemes can be employed to accommodate intermittency associated with a power station source that is not running at base load.

At first glance, this may suggest that CCS operations in saline formations would be more prone to suffer consequences from intermittent supplies. However, two factors suggest that this may not be the case. First, storage in saline formations at many locations may require the use of water production wells to control $CO_2$ plume geometry and pressure front movement, in which case solutions developed for the EOR industry that include the use of recycled $CO_2$ to mitigate supply intermittency will likely apply. Secondly, because of their lack of hydrocarbons, and therefore lack of historical fluid withdrawal as part of production operations, saline formation reservoirs are likely to exhibit initial reservoir pressures that are higher than those in oil and gas reservoirs. Once established and operating, a project can be more adaptive. Operators historically have proven to be able to adapt to variability.

With respect to wellbore integrity, fatigue and corrosion are considered to be the most likely effects of intermittent flow. This is particularly true in wells that see the injection of mixed-gas streams (e.g., $CO_2$ and $H_2S$) because changes in the pressure of the gas column in the wellbore caused by stopping injection can result in deleterious phase behavior, including segregation of the component gases. This can lead to issues when injection is started up again, including fatigue and corrosion of wellbore materials. The Joule-Thomson effect caused by pressure drop can also be extreme, leading to freeze-up of valves and joints. Using standard oil and gas engineering protocols, the potential for intermittency is factored into the development of the operating conditions. Contingency plans are developed accordingly and implemented if necessary.

Variable or intermittent $CO_2$ supplies can diminish injectivity or damage project infrastructure through pressure and temperature changes. According to the literature, hydrate formation and salt precipitation have the greatest impact. Gas hydrates are cage-like, crystalline lattices of water (clathrates) that contain methane. Hydrate formation may be the most dramatic consequence of flow interruption as it can cause both diminished injectivity and rapid corrosion. Fortunately, hydrate formation is reasonably predictable given an understanding of the pressure and temperature regimes existing in the system as well as the water fraction of the injectate stream. Hydrate formation is also generally preventable using multistage compression and knockout systems as well as inclusion of monoethylene glycol into the stream.

Salt precipitation (and perhaps asphaltenes, paraffins, and calcite precipitation) could feasibly be exacerbated by intermittent dry $CO_2$ flow, if the pressure regime is favorable. Prior knowledge of the reservoir characteristics and injectate composition can be applied using standard engineering principles to design and operate injection schemes that minimize the negative effects of $CO_2$ supply intermittency.

Impurities in a $CO_2$ stream may impact geologic storage, although this is likely to be reservoir-specific and depend on the mineralogical and fluid compositions and the type and amount of impurity. The impacts can vary from slight dissolution that creates microvoids to mineralization that fills the pore space. Noncondensable impurities in a $CO_2$ stream may reduce the density of the gas stream, which would lead to a drop in the total storage capacity of a reservoir. The formation of stronger acids because of the presence of water and $SO_2$ or $H_2S$ can reduce the pH of the formation water, forming a highly acidified zone in which rapid mineral dissolution of carbonate and silicate minerals may actually increase the porosity. However, at the edge of the injection zone, the increase in pH would result in the precipitation of secondary minerals, which can reduce the porosity and, potentially, the formation permeability.

There has been concern regarding possible linkage between variability in $CO_2$ injection rate and induced seismicity. The open literature suggests that a variety of factors related to $CO_2$ injection might contribute to increased seismicity, although studies appear to agree that the current state of knowledge has limited ability to predict seismicity. It appears that, unless variability produces excessive rates, pressures, volumes, or other conditions, the effect of $CO_2$ variability upon seismicity is too subtle for the current state of knowledge to identify or predict.

The almost inevitable changes in pressure within pipelines, wells, and equipment that are likely to accompany variability or interruptions in flow have the potential to cause unintended multiphase flow and unanticipated corrosion properties. However, the EOR industry in the United States has proven that it is possible to adapt to variability and intermittency in $CO_2$ supply. The use of multiple wells is crucial to successful injection at a storage site, particularly for pressure control, for water disposal, to reduce project liability, and to enable the operator to adapt to variability in $CO_2$ supply. Such $CO_2$ pipeline and injection experience represents knowledge that can be applied in future CCS projects. The fact that the EOR industry in the United States has moved millions of tonnes of $CO_2$ through pipelines and injected it into the subsurface for decades indicates that, even when stream variability occurs, pipeline engineers and injection operators have the capability to deal with issues that arise and minimize their impact on the operability of either the pipeline or the injection infrastructure.

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# APPENDIX A

# EXPERTS CONTACTED DURING DATA COLLECTION

# EXPERTS CONTACTED DURING DATA COLLECTION

Fourteen unique individuals were contacted who represented ten organizations and six industrial processes from North America and Europe. The responses were considered to be business-sensitive, so neither the individuals nor their companies are identified here. Following are their areas of expertise:

- Carbon capture and storage consulting
- Natural gas processing
- Petroleum refining
- Hydrogen production
- Gasification
- Electric power generation
- Oil companies
- Cement production

# APPENDIX B

# $CO_2$ PIPELINE INCIDENTS IN THE UNITED STATES FROM 1994 THROUGH 2008 AND 2009 THROUGH MAY 2014

## $CO_2$ PIPELINE INCIDENTS IN THE UNITED STATES FROM 1994 THROUGH 2008 AND 2009 THROUGH MAY 2014

**Table B-1. Descriptions of $CO_2$ Pipeline Incidents from 1994 Through 2008**

| Date of Incident | Description of Incident | Cause | Location | Suspected Responsible Party |
|---|---|---|---|---|
| 2/27/1994 | Hazardous liquid pipeline/gasket failure. | Equipment failure | Texas | Inron Liquids Pipeline Company |
| 4/15/1994 | 8-in. pipeline/external corrosion. | Equipment failure | Oklahoma | Arco Permian |
| 6/15/1998 | 12-in. $CO_2$ pipeline/U.S. Department of Transportation regulated/semitruck ran into a structure. | Operator error | Oklahoma | Transpectco |
| 11/19/2000 | Strong odor reported from private citizen and confirmed release from pipeline 12 in. below ground. | Equipment failure | North Dakota | Dakota Gasification Company |
| 1/13/2001 | 8-in. transportation line discovered leaking into the atmosphere because of an unknown cause. | Unknown | North Dakota | Dakota Gasification Company |
| 2/25/2001 | 12-in. distribution line leaked $CO_2$ and $H_2S$ into atmosphere. | Equipment failure | Texas | Borger $CO_2$ Pipeline LLC |
| 3/7/2002 | Third-party company contracted a backhoe and hit a $CO_2$ underground pipeline during digging. | Operator error | Oklahoma | |
| 2/25/2003 | 8-in. transmission pipeline failed because of corrosion and caused material to release. | Equipment failure | Texas | Chaparral Energy |
| 11/14/2003 | Release of $CO_2$ because of valve failure. | Equipment failure | Mississippi | Denbury Resources |
| 10/14/2004 | A leak was found on the CRC pipeline releasing $CO_2$. | Under investigation | Texas | Kinder Morgan $CO_2$ Company |
| 9/22/2006 | A magnetic flux leakage (MFL) pig was struck in a pipeline, and when efforts were made to remove the object, the line developed a crack and discharged $CO_2$ into the air. | Equipment failure | North Dakota | Dakota Gasification Company |
| 1/9/2007 | $CO_2$ was released to the atmosphere from a 20-in. underground pipeline. | Unknown | Mississippi | Denbury Onshore LLC |
| 3/15/2007 | An ice mound formed on a line used for liquid $CO_2$ injection from Texas to Oklahoma because of a pinhole leak. | Equipment failure | Texas | Chaparral Energy |

Source: URS Corporation, 2009, Revised application for certification for HYDROGEN ENERGY CALIFORNIA, Kern County, California: Volume II, Appendix E, May, 2009, p. 2-1.

**Table B-2. Descriptions of $CO_2$ Pipeline Incidents from 2009 Through May 2014**

| Date of Incident | Description of Incident | Cause | Location | Suspected Responsible Party | Amount, bbls |
|---|---|---|---|---|---|
| 7/2/2009 | Coating in area around leak site failed because of lack of maintenance; moisture content of the soil, failed coating, and previous lack of cathodic protection contributed to the event. | External corrosion | Oklahoma | Chaparral Energy, LLC | 850 |
| 7/30/2009 | Relief valve vented $CO_2$ because of malfunction; opened below set pressure. Valve spring failure was thought to be the problem. | Component material and/or weld failures | Texas | Kinder Morgan $CO_2$ Co. LP | 224 |
| 8/2/2009 | Pump inboard seal failure. | Ruptured or leaking seal/pump packing | New Mexico | Kinder Morgan $CO_2$ Co. LP | 0.1 |
| 9/8/2009 | | Equipment | Texas | Kinder Morgan $CO_2$ Co. LP | 0.1 |
| 3/1/2010 | When a relief valve on the $CO_2$ pipeline vented, the pipe below the valve failed, damaging the relief system. The leak occurred because of a design flaw in the support for the relief valve. | Miscellaneous | Kansas | Chaparral Energy, LLC | 2.99 |
| 5/12/2010 | A small thread leak on a ½-in. grease port plug in a mainline valve was discovered. | Threaded connection/coupling failure | Texas | Kinder Morgan $CO_2$ Co. LP | 0.53 |
| 8/9/2010 | Relief valves within the pipeline opened and vented because of an overpressure from a third-party operator during changes to its operating system. | Miscellaneous | Texas | Kinder Morgan $CO_2$ Co. LP | 0.37 |
| 10/21/2010 | Relief valve vented to a pressure surge from third-party pump facility. The initial set point was set too low for the established maximum operating pressure of the line. | Miscellaneous | Texas | Kinder Morgan $CO_2$ Co. LP | 299 |

Continued…

**Table B-2. Descriptions of $CO_2$ Pipeline Incidents from 2009 Through May 2014 (continued)**

| Date of Incident | Description of Incident | Cause | Location | Suspected Responsible Party | Amount, bbls |
|---|---|---|---|---|---|
| 11/29/2010 | A small leak was found on the 5-valve manifold attached to the electronic flowmeter on the meter run. The leak was due to damage to Teflon gaskets during installation. | Nonthreaded connection failure | Texas | Kinder Morgan $CO_2$ Co. LP | 26 |
| 12/20/2010 | A leak occurred at an ERW weld and is attributed to an imperfection in the weld. | Weld failure, original manufacturing-related | Louisiana | Denbury Onshore, LLC | 70191.3 |
| 1/18/2011 | A leak occurred in a valve during valve maintenance. | Malfunction of control equipment | Mississippi | Denbury Onshore, LLC | 1 |
| 2/10/2011 | A leaking relief valve O-ring cause a leak. | Nonthreaded connection failure | New Mexico | Transpetco Transport Co. | 2530 |
| 2/14/2011 | Leak occurred at the crossing of Denbury pipeline with two other pipelines. Leak was at a joint. | Material failure of pipe or weld, original manufacturing-related | Texas | Denbury Green Pipeline-Texas, LLC | 43,182.4 |
| 2/24/2011 | $CO_2$ release at the pig launcher because of a damaged O-ring. | Nonthreaded connection failure | Louisiana | Denbury Gulf Coast Pipelines, LLC | 26.5 |
| 4/3/2012 | Thermal relief valve prematurely vented. Relief valve was specified with incorrect seat material during preconstruction phase. | Wrong equipment specified or installed | Texas | Kinder Morgan $CO_2$ Co. LP | 3.88 |
| 4/6/2012 | Thermal relief valve prematurely vented. Relief valve was specified with incorrect seat material during preconstruction phase. | Wrong equipment specified or installed | Texas | Kinder Morgan $CO_2$ Co. LP | 15.15 |
| 1/30/2013 | A $CO_2$ leak on a 4-in. bypass globe valve developed because of deterioration of the packing seal over time. | Nonthreaded connection failure | Texas | Kinder Morgan $CO_2$ Co. LP | 20.54 |
| 6/10/2013 | The ground had heaved above a pipeline. A leak developed because of a pinhole in a girth weld on the top of the pipe. | Material failure of pipe or weld construction | New Mexico | Transpetco Transport Co. | 20803 |

Continued…

**Table B-2. Descriptions of $CO_2$ Pipeline Incidents from 2009 Through May 2014 (continued)**

| Date of Incident | Description of Incident | Cause | Location | Suspected Responsible Party | Amount, bbls |
|---|---|---|---|---|---|
| 7/27/2013 | The bleeder safety valve on the Huber closure door of the pig receiver was leaking. | Nonthreaded connection failure | Texas | Kinder Morgan $CO_2$ Co. LP | 2.8 |
| 10/15/2013 | 3-in.-diameter ice ball was spotted. Leak was found in a joint weld. The leak occurred because an original girth weld that had to be repaired was not done correctly. | Material failure of pipe or weld construction | Mississippi | Genesis Free State Pipeline, LLC | 0.1 |
| 11/23/2013 | The cause of this accident is still being investigated; a pipe section has been removed for testing. | Material failure of pipe or weld | Oklahoma | Chaparral Energy, LLC | 643.8 |
| 5/2/2014 | A relief valve failed to open because of a worn spring release inside the valve vault of the relief valve. | Relief equipment malfunction | Texas | Kinder Morgan $CO_2$ Co. LP | 2066 |

Source: U.S. Department of Transportation, Pipeline & Hazardous Materials Safety Administration, 2014, 2014-06-04 PHMSA Pipeline Safety – Flagged Incidents.zip: Retrieved from primis.phmsa.dot.gov/comm/reports/safety/data/ 2014-06-04 PHMSA Pipeline Safety – Flagged Incidents.zip?nocache=8315 on July 9, 2014.