SAFE STORAGE OF CO_2: EXPERIENCE FROM THE NATURAL GAS STORAGE INDUSTRY

Technical Study

Report Number: 2006/2

Date: January 2006

INTERNATIONAL ENERGY AGENCY

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The report should be cited in literature as follows:

IEA Greenhouse Gas R&D Programme (IEA GHG), "Safe Storage of CO_2: Experience from the Natural Gas Storage Industry", 2006/2, January, 2006.

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Background

The storage of CO_2 in geological formations is an attractive mitigation option because it offers the potential to achieve deep reductions in atmospheric greenhouse gas emissions, when used in conjunction with other options like energy efficiency and renewable energy. The main geological formations that are being considered for CO_2 storage include: depleted oil and gas fields, deep saline aquifers and deep unminable coal seams. Many advocates of geological storage, point to the fact that the geological formations considered have held hydrocarbons and saline water for many millions of years and hence their integrity has been demonstrated. They then extrapolate this point to suggest, that the integrity of the formations to store CO_2 for geological timescales can be assured for that reason. However, such an assumption alone is unlikely to assure all parties in the debate that CO_2 cannot migrate out of these reservoirs. To demonstrate effective retention of injected CO_2 other measures are needed. Such measures include: monitoring of CO_2 injection projects, risk assessment studies and the development of rules and standards for CO_2 storage. All these actions will help to build confidence in CO_2 storage as a global mitigation option and help allay fears that injected CO_2 will seep to the surface (to any significant degree) and cause adverse ecosystem or environmental damage. Such activities are now underway worldwide. However it may be several more years before a credible data base is established that will allow the issue of security of storage to be finally answered. In the intervening period, this issue will represent a potential barrier to the introduction of CO_2 storage technology.

To help to address this barrier in the near term it will be useful to consider industrial analogues for CO_2 storage, one such analogue is natural gas storage. The storage of natural gas in geological formations has been underway in many parts of the world, notably North America and Europe since the 1970's. Both these regions are developing projects for CO_2 storage. There is, therefore, experience from the natural gas storage industries in North America and Europe that can be drawn upon to assist the development of the CO_2 storage industry. Also, since natural gas is a valuable commodity and flammable gas, best efforts are made to minimise loss from any storage facility. If this experience can be drawn upon to the benefit of CO_2 storage then this might help allay fears over the potential for CO_2 leakage in the near term.

The aim of this study is to review the regulatory processes and operational practises within the natural gas storage industry and assess their applicability to CO_2 storage. The objective of the study will be to develop a report that can act as a reference manual for IEA Greenhouse Gas R&D Programme (IEA GHG) members in their discussions with policy makers and environmental pressure groups to demonstrate that geological can be a safe and environmentally friendly mitigation option

The study was undertaken by Woodhill Frontier of the UK. The study build upon an earlier study undertaken by the CO_2 Capture Project which was made available to IEA GHG are a reference source for this activity.

The study was completed in co-operation with the CO_2 Capture Project (CCP) and aimed to build upon a technical study undertaken by CCP during Phase 1 of its research programme[1].

[1] In CCP1 a study was commissioned from the Gas Technology Institute, USA which focused on the technology developed by the natural gas storage industry and it applicability to CCS. THE IEA GHG study extended this work by looking at regulatory experience and by deriving failure frequency analyses for well bores. Full details of the CCP study undertaken can be found in CO_2 Capture for Storage in Deep Geologic Formations – Results from the CO_2 Capture Project. Vol. 2: Geologic Storage of CO_2 with Monitoring and Verification, Edited by Sally Benson, Elsevier, 2005, pp 815 to 826.

Results and Discussion

The following aspects are discussed in this overview. Full details on all these topics are presented in the main report:

- Review of natural gas storage activities
- Regulatory issues
- Site selection
- Natural gas leakage incidents and incident frequency
- Well design and abandonment issues

Review of natural gas storage activities

Underground natural gas storage is undertaken in some 25 countries around the world all of which have regulations to cover these activities. In total, some 340 billion m^3 of natural gas is stored annually in some 634 underground natural gas storage facilities. This volume of natural gas roughly equates to 910 Mt CO_2. With current annual CO_2 emissions from the power sector at 8200 Mt in 2002 this represents some 11% of annual emissions. Therefore, whilst there is a substantial amount of gas already stored, we will have to expand this storage capacity considerably to store sufficient CO_2 to reduce global warming. Never the less the natural gas storage sector represents a significant knowledge base on subsurface gas storage that can be drawn upon in the development of CO_2 capture and storage.

Almost 32% of the natural gas stored is stored in the USA, with a further 27% in Russia and 9% in the Ukraine. The USA has by far the most underground natural gas storage facilities some 410 in total, followed by Canada (45), Germany (40) and Russia (25)[2]. North America, in particular, therefore has considerable operational and regulatory experience in the underground storage of gas that can be drawn upon for CO_2 storage.

Most of the natural gas is stored in depleted oil and gas fields (83.5%), followed by aquifers (12.6%)[3]. Oil and gas fields are considered to be more attractive stores because their establishment costs[4] are lower than for aquifers. Based on current capacity estimates it is considered that aquifers offer the largest storage potential for CO_2. Estimates for aquifers vary from 1,000 to 10,000 $GtCO_2$, whilst those for oil and gas fields are typically 900 $GtCO_2$. Experience from the natural gas storage industry indicates that considerable exploration work will be needed on aquifers to build up sufficient geological data to be confident that the aquifer potential can be fully realised.

In North America, most of the natural gas storage sites are less than 800m deep, whilst in Europe they tend to be deeper than 800m. For CO_2 storage a depth of 800m is taken as the reference point below which the CO_2 will be supercritical. These statistics suggest that underground natural gas storage and CO_2 storage are not competing for the same reservoirs in North America[5], but this might be the case in Europe. However, the number of oil and gas reservoirs utilised for gas storage is much lower in Europe

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[2] It is noted that the volumes of gas stored per storage reservoir must be much greater in Russia than in the USA. This is probably not surprising because Russia does have a lot of large on shore gas fields compared to the USA.

[3] The remaining storage options include; salt caverns, abandoned mines and rock caverns

[4] The establishment costs are lower due to a number of reasons one of which is that there is already geological data on the gas and oil fields from exploration and production activities, the same is not true for aquifers. Also there will not be any existing infrastructure (wells, pipelines, compressors etc.,) that can be utilised for aquifers. Cushion gas requirements for oil and gas fields can also be lower than for aquifers. In aquifers there is no native gas and hence large volumes of gas will need to be added, which may not be recoverable on abandonment, which again adds to establishment costs.

[5] In North America it is considered that the onshore storage potential is sufficient to meet the needs for CO_2 storage.

and the large reservoirs that are attracting most interest for CO_2 storage are offshore in the North Sea[6] and are not typically those used or being considered for natural gas storage.

Regulatory issues

The review of legislation covering natural gas storage has suggested that this legislation could be used as a starting point for the development of CO_2 storage regulations. A general, principal of natural gas legislation is that it assumes that natural gas stored underground is an expensive commodity, which must be preserved from escaping the formation. Whilst CO_2 cannot yet be considered as a commodity this general principal could also be applied to CO_2 storage.

Based on the experience of the natural gas storage industry the consultant has indicated that any regulatory process for CO_2 storage should include the following aspects:

- A safety/risk assessment,
- An environmental impact assessment, with public consultation[7],
- A detailed site selection programme (site selection is discussed in more detail later in this overview); this would include detailed geological and hydrological studies of the site and surrounding areas,
- Control on injection pressures to avoid over pressurisation of the reservoir and hence reduce the risk of fracturing the cap rock that would compromise reservoir integrity,
- An emergency plan in the event of a leakage occurring – this should cover the operational phase and conceivably the post operational phase as well,
- A detailed monitoring programme of both the surface and subsurface,
- Record keeping for all abandoned wells.

It is noted that natural gas storage legislation only addresses liability for environmental incidents and damage to property during the operational phase of a storage project. The issue of post operational liability is an important one for CO_2 storage because unlike natural gas storage the geological formations will be filled with gas after operations have ceased not emptied. However, experience suggests that after wells and sites have been abandoned the government has either directly, or indirectly, eventually has assumed liability for the site. Note: the term indirectly has been used in the preceding sentence because after operations had ceased, there were instances where companies also failed to continue to exist and hence any post operational liability could not be assigned back to them. In that case, government bodies had to assume responsibility. Again this is a big issue for CO_2 storage, where the CO_2 might have to remain stored for 100's or 1000's of years after a storage site has been closed and any leakage that occurs will need to be remediated by somebody[8].

Site selection

Experience from the natural gas industry on site selection is directly applicable for CO_2 storage. In the selection of CO_2 storage sites the study has identified three key issues that need to be considered are: containment, induced seismicity and associated risks. As far as containment is concerned experience from the natural gas storage industry would indicate the need for thick[9] cap rocks (preferably with further overlying cap rocks) because these are essential to minimise the risk of gas loss. Cap rock

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[6] IEA Greenhouse Gas R&D Programme Report No. 2005/2 Building the Cost Curves for CO_2 Storage: Europe. February 2005

[7] Public consultation was considered important because public acceptability of the technology could have a strong influence on storage site selection and widespread implementation of CCS.

[8] IEA Greenhouse Gas R&D Programme Report No. Ph4/35 November 2004, Overview of long term framework for CO_2 capture and storage. November 2004.

[9] It is noted that the term thick is somewhat general but specific guidance on cap rock thickness was not available from the review.

integrity assessment techniques developed by the natural gas storage industry are directly applicable to CO_2 storage[10]. In addition, overlying alternating successions of aquifers could provide additional safety features if leakage were to occur[11]. However, it is noted that in all cases overlying aquifers may not occur. Related to the issue of containment is that of induced seismicity – clearly sites where CO_2 injection could induce microsesimic events that could reduce the effectiveness of gas containment should not be considered for CO_2 storage. Associated risks – these could result due to adjacent facilities such as abandoned wells/water production wells etc. There is one particular incident (Yaggy, Kansas, USA) where unplugged abandoned water injection wells led to significant surface leakage of natural gas (see main report for more details).

Other issues that might have a bearing on site selection in the natural gas storage industry are: proximity to dwellings and other facilities (industrial etc.,) in the event of a leak, proximity to potable water supplies and their potential contamination and local topographical features. All of these issues are relevant to CO_2 storage, clearly the closer any storage facility is to buildings and people raises the risk of human health problems arising in the event of a leak occurring. The protection of potable water supplies will remain an important issue in countries like the United States[12]. The issue of local topography might be more important for CO_2 because of its density and its resulting tendency to accumulate at ground level. In this case, ground depressions, building with cellars/basements, steep sided valleys with low wind ingress might cause CO_2 to accumulate and must be considered in any site assessment.

Natural gas storage incidents and incident frequency

A review of documented data from the 1970's onwards identified seventeen accidents, associated with fugitive emissions[13] gas from natural gas storage facilities. The cumulative years of natural gas storage site and well operations were calculated as 20,271 years and 791,547 well-years, respectively. Of the incidents identified, one occurred during maintenance of surface equipment and was not included in the natural gas storage leakage frequency calculation; and the remaining sixteen were associated with underground causes (principally, well failures). Only two of these incidents resulted in fatalities.

The incident frequencies associated with these facilities, were then calculated, which were:

- The frequency of a major incident from a natural gas storage facility was calculated as $8.39x10^{-4}$ /site-yr, or once every 1,192 years of site operation.
- The frequency of a major incident from a natural gas storage well calculated as $2.02x10^{-5}$ /well-yr, or once every 49,505 years of well operation.

These results were compared with a European study undertaken by Marcogaz[14]. Here the sample was smaller and the accident frequency from well failure was calculated as $5.1x10^{-5}$ accident/well-yr. A separate data source from blow outs from oil and gas reservoirs was also accessed for comparison. Production blow-out frequency estimates, were considered more appropriate to approximate a major

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[10] Cap rock integrity techniques include: geological assessments, threshold pressure measurements and pump tests. Details of these techniques are given in the main report.

[11] The presence of overlying aquifers at the Weyburn oil field, Saskatchewan, Canada and their potential role in preventing the upward migration of any CO_2 that should leak out of the oil field has been highlighted as a reason why surface seepage of CO_2 is not expected at Weyburn.

[12] Injection regulations like the Underground injection Control (UIC) Programme in the USA are framed to protect drinking water supplies from contamination of gases and liquids into the subsurface.

[13] A fugitive emission can be considered as a release of gas resulting from a mechanical failure of a piece of well equipment. Such an emissions could last for a few minutes or a few hours depending on the particular component that has failed and the time required to remediate any emission. No effort was made to determine the volume of any fugitive emission that occurred, however they can be considered as limited in volume compared to the total volume injected annually and to be of short duration. Such emissions from process operations are reported routinely in national inventories.

[14] Marcogaz is the technical association of the European natural gas storage industry. Details of their activities can be found at: www.marcogaz.org.

uncontrolled fugitive emission from a gas storage well, compared to a wire line or work over blow outs. Data from a study in the Netherlands gave a production blow out frequency of $5x10^{-5}$ per well-yr or a major gas release from a well once every 20,000 well-years.

These incident statistics show that failures of mechanical components in wells will occur, albeit at a low frequency. As a result fugitive emissions from operational wells at natural gas storage sites also occurs. If similar well designs and operational practices are undertaken at CO_2 storage sites comparable to natural gas storage sites will can also infer that fugitive emissions can also be expected. However the volumes of such emissions cannot be estimated, but are expected to be very low compared to the volumes of gas injected annually at a storage site. In total, the number of incidents that are referenced is small and the credibility of the statistics from such a small sample could be questioned. It must also be noted that in both the USA and Europe the incidents of well failures were similar in the 1970 and 1980's but decreased significantly in the 1990's. This decrease can be interpreted as being due to improved operational practices and regulatory improvements.

Well design and abandonment issues

Well bores are clearly an issue in the natural gas storage industry as indicated earlier by the fact that most major incidents occurred as a result of well bore failure. In the design of wells it is important that the casing cement fully isolates the well from the surface preventing both gas migration and ingress of fluids into overlying aquifers. Such isolation may be required for 100's to 1000's years. Conventional Portland cements are known to be susceptible to attack by carbonate ions and their integrity can in some cirumstances[15] be compromised. Alternative CO_2 resistant cement are available and could be used for CO_2 storage applications, however, they are considered to be more expensive. For abandoned wells on CO_2 storage sites it might be appropriate to consider longer isolation plugs than are currently used (typically 30m or 100 feet) to ensure effective isolation for the long time frames required.

Expert Group Comments

The draft report on the study was sent to a number of expert reviewers and IEA GHG's members who had expressed interest in reviewing it. The study was generally well received by the reviewers. Most of the comments received were general in nature and referred to general issues on the report contents which have been addressed by the contractors in the final draft of the report. One reviewer raised a number of specific issues and asked for further clarification on a number of points to be included within the report. These issues, which were not fundamental in their nature, were discussed by the contractors and the IEA GHG project manager concerned and, where appropriate, modifications to the reports contents were agreed and then implemented by the contractor.

[15] The physical mechanism(s) by which CO_2 dissolved in solution can react with Portland cement and lead to degradation of the cement is not yet fully understood.

Major Conclusions

The study has highlighted that there is a considerable knowledge base within the natural gas storage industry that is relevant to the development of CO_2 storage. Two particular issues have been highlighted: that of well bores and site selection. The statistical data available suggests that well bore failures do occur at a low frequency at operating natural gas storage reservoirs. As a result fugitive emissions of stored gases occur. When developing regulations for CO_2 storage sites, wells, therefore, offer a number of challenges.

In the case of operational wells, it would seem that the use of existing procedures for well design, maintenance and operation, based around existing industry best practice, should be sufficient to ensure a low risk frequency for well failure. This frequency could be further reduced, however, if these current regulations are reinforced. One potential reinforcement area would be if new CO_2 resistant cements are prescribed. It must be noted that the use of such cements, this is not typical practice and there will be cost implications that will have to be borne by the operator. However, any increase in cost might be considered worthwhile if it can be demonstrated that it reduces the potential risk of well bore failure and will reduce fugitive emissions at CO_2 storage sites. Such actions might well be considered as highly desirable for CCS projects to improve the public acceptability of the technology.

For abandoned wells, however, the regulatory issues become more contentious. As part of a selection process for a new storage site one can expect that regulations could require all abandoned wells and their abandonment status to be identified. This task in itself represents a challenge because it assumes that records covering 50 to 100 years of operation on some potential suites are available that identify the positions of the wells and how they have been abandoned. Also, it is probably not possible at this stage to determine with any confidence if these abandoned wells will leak over the timescales that will be considered for CO_2 storage, i.e. 100’s to 1000’s of years. One possible consideration would be to go back into these wells and re plug them with CO_2 resistant cement. Again this could involve a cost issue, however, it if it were demonstrated that such actions improved the containment potential for any stored CO_2 and increased the publics confidence that CO_2 could be stored safely such actions could be deemed to be attractive. An alternative would be to monitor each well for leakage throughout the lifetime of the project and for years after project closure, coupled with the development of a remediation plan. It will, therefore, be necessary to consider the cost implications of such actions against the risk profile for a site to determine if the additional costs substantially reduce the risk of loss of containment of any injected CO_2. Such an analysis would need to consider the appropriate balance between any increased cost placed on operators and the increased confidence gained in the safety of the technology by the general public.

Recommendations

The main recommendations that can be drawn from this study are that the effective site selection is important to ensure that CO_2 can be safely stored for the necessary timescales after it is injected. Wells have once again been highlighted as a potential issue with regard to leakage from a storage reservoir, this time in the case of operational wells. Any regulatory process for CO_2 storage needs to pay careful attention to the issue of wells (both operational and abandoned) and reinforcement of existing industry best practice might be considered appropriate because of the long storage times required for injected CO_2.

DOCUMENT SUBMITTED TO

IEA GREENHOUSE GAS R&D PROGRAM

SAFE STORAGE OF CO_2

EXPERIENCE FROM THE NATURAL GAS STORAGE INDUSTRY

PREPARED BY

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Safe storage of CO_2: experience from the natural gas storage industry

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Revision record

This document is issued in accordance with the Woodhill Frontier quality management system. Revisions may comprise a complete issue, or issue of individual pages as noted in the table below.

C	07Oct05	revised	various	NP	BML	WAH
B	21Jul05	revised	various	NP	BML	WAH
A	06Jul05	initial issue	not applicable	NP	CJH	WAH
rev	**date**	**description**	**revised pages**	**by**	**chk'd**	**app'd**

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GLOSSARY OF TERMS AND ABBREVIATIONS

For the purposes of this report the following definitions apply.

annulus	The space between the outer wall of a well tubular or pipe and the inner wall of the next tubular or the borehole wall
acid gas	Mixture of gases that may contain significant quantities of H_2S and CO_2
AFNOR	Association Francaise de Normalisation
AGA	American Gas Association
ANSI	American National Standards Institute
ALARP	As low as reasonably practicable, statement about the extent to which risk has been reduced. This is commonly used in a European context
API	American Petroleum Institute
AOR	Area of review
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
base gas or cushion gas	The volume of gas required to maintain adequate pressure to ensure the deliverability of the working gas. Base gas is rarely, if ever, produced
BCF	Billion cubic feet
BSI	British Standards Institute
borehole	The hole made by drilling a well
CCP	CO_2 capture program
cement	A substance consisting of alumina, silica, lime and other materials that hardens when mixed with water. In wells it is used to support and hold casing and is also used to isolate sections within a borehole from each other
cement plug	A volume of cement placed at some interval inside the wellbore to prevent fluid movement
CEN	European committee for standardization
CO_2	Carbon dioxide
code	A document that is often strictly applied without deviation. Eg, ASME Boiler and Pressure Vessel Code, Section VIII, Pressure vessels - divisions 1 and 2
code of practice	Synonymous with code
company engineering practice	A document prepared or adopted by an operating company that is used for guidance by that company and its contractors
contractor	A company that performs services for an operating company such as engineering, procurement, construction and operations support
CSA	Canadian Standards Association
cycling	The number of times the working gas volumes are injected/withdrawn in a year
deliverability	The amount of gas that a storage reservoir is capable of producing to sales
dense phase	Dense phase is a state of a material where it is possible to move from a liquid to a gas without an interface between the two ever becoming visible
DIN	Deutsches Institut für Normung
DNV	Det Norske Veritas
document	A document formally issued by an official organisation and usually subject to revision and update

DOE	Department of Energy (US)
DOT	Department of Transport (US)
DTI	Department of Trade and Industry (UK)
EIA	Environmental impact assessment
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency (US)
EU	European Union
EUB	Energy and Utilities Board (Alberta)
GCS	Geological CO_2 (carbon dioxide) storage
GPA	Gas Processors Association
GPSA	Gas Processor Suppliers Association
guidelines	A document issued by an official organisation, giving guidance
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulphide
HPHT	High pressure high temperature
HSE	Health and Safety Executive (UK)
IEA	International Energy Agency
IEA GHG	International Energy Agency Greenhouse Gas R&D Program
inactive well	A well where production, injection, disposal or workover operations have ceased, but permanent abandonment has not taken place
industry practice	Common practice within industry often reported in industry journals and publications and possibly not covered by a document
industry standard	A document used to give design information for components. Eg, API 610 Centrifugal pumps for petroleum, heavy-duty chemical, and gas industry
ISO	International Organization for Standardization
JIS	Japanese Industrial Standards
LC	The Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (the London Convention) and the 1996 Protocol to the Convention
LEL	Lower explosive limit
MIT	Mechanical Integrity Test
MSS	Manufacturers Standardization Society of the Valve and Fitting Industry
NACE	National Association of Corrosion Engineers, (USA)
NETL	National Engineering Technology Laboratory, US Department of Energy
NFPA	National Fire Protection Association, (USA)
NNI	Nederlands Normalisatie-Instituut
NIOSH	National Institute for Occupational Safety and Health, (USA)
NOx	Nitrogen oxides
NSC	North Sea Convention
NSF	Norges Standardiseringsforbund
official organisation	A body that issues documents giving regulations, rules and guidance. Official organisations can be governmental or non-governmental and are often supported by technical professionals
O&M	Operating and maintenance

operating company	A company that is responsible for the operation of a facility. This normally includes the safety aspects of design, construction, operation and decommissioning
OSPAR	The Convention for the Protection of the Marine Environment of the North-East Atlantic
O&M	Operating and maintenance
PPC	Pollution Prevention and Control Regulations
QRA	Quantitative Risk Assessment; A technique that uses known frequencies of individual constituent events to assess the likelihood of other events. Typically this technique is applied in a European context to the assessment of the acceptability of a hazard
recommended practice (RP)	A document used for guidance, often for the design of multi-component systems.
regulation	A government document that normally takes precedence over other Documents.
reservoir	Subsurface volume that can hold fluids
ROV	Remote operating vehicle
RSPA	Research and Special Programs Administration
SACS	Saline Aquifer CO_2 Storage project, currently underway in the Sleipner field of Norway
sour gas	A gas that has trace quantities of H_2S
SPE	Society of Petroleum Engineers
specification	A document used to assist the procurement of components. Eg, API Specification 12F, Specification for shop welded tanks for storage of production liquids
standard	A document issued by a standards organisation such as ISO, ASME, DIN or ASI.
Standards Organisation	An official organisation that issues internationally recognised documents
SSSV	Subsurface safety valve
surface facility	Process plant and piping at the surface
UCGS	Underground carbon gas storage
UCS	Underground carbon storage
UGS	Underground gas storage
UIC	Underground injection control
UNGS	Underground natural gas storage
USDW	Underground source of drinking water
VER	Verified emissions reductions
VOC	Volatile organic components
working gas	This is the gas that is available to produce and sell during the withdrawal period and inject during the fill period
WFL	Woodhill Frontier Limited
well	A drilled borehole cased with tubulars
wellbore	The interior surface of the cased or open hole through which drilling, production, or injection operations are conducted
ZEI	Zone of endangering influence

SUMMARY

Underground gas storage experience dates back to the beginning of the last century, with the first underground natural gas storage (UNGS) reservoir beginning operation in 1915 in Ontario, Canada. The purpose of this study was to gather information on regulatory processes and operational practices from the natural gas storage industry, with regards to depleted reservoirs, converted aquifers, UNGS facilities, and to assess their applicability to geological CO_2 storage (GCS). In summary, the scope of work was as follows.

- Review characteristics of global UNGS facilities and UNGS legislation from USA, Canada and northern Europe. Highlight regional differences and assess their applicability to GCS.
- Review information on UNGS leakage incidents. Derive a UNGS leakage frequency and discuss its relevance to GCS.
- Review practices and constraints for UNGS site selection and assess their relevance to GCS.
- Review operating practices for inventory monitoring, verification, leakage detection and remediation and assess their relevance to GCS.
- Assess relevant UNGS design and operational aspects to GCS.

The main conclusions of this report concerning GCS, are as follows.

- Competition for geological space between UNGS and GCS is considered to be unlikely in North America but is possible onshore in Europe.
- Legislation indicates the need for clarifying whether CO_2 is a ‘waste material’ or a ‘valuable commodity’.
- Experience indicates that the transfer of long-term liability to government bodies is inevitable; therefore, consideration should be given to limiting the duration of the operator liability once injection has ceased.
- Observation wells are more likely to be used for GCS projects in converted aquifers.
- A minimum post-injection monitoring period with observation wells should be considered. Following this monitoring period, observation wells should be plugged and abandoned.
- The main criteria used for UNGS site selection are formation containment and costs. Existing installations for depleted reservoirs and the use of enhanced oil recovery (EOR) techniques could reduce GCS capital and operating costs.
- In the UK, depleted reservoirs have more advantages for GCS over aquifers, and North Sea reservoirs could be suitable candidates for GCS projects.
- From the UNGS leakage frequency incidents identified, the frequency of a significant CO_2 leakage was calculated as 2.02×10^{-5}/well-yr or once every 49,505 years.
- The main concern with existing technology is wellbore plugging and abandonment, especially the long-term effects of CO_2 on cement and casing.

The main recommendations are as follow.

- Assess municipal and hazardous (eg radioactive) waste legislation, and the legal position for radon leakage, for any analogues with GCS.
- Further research is required on the long term effects of CO_2 on cement and casing and the integrity monitoring of abandoned wells, especially cement plugs and corrosion of the casing.
- Additional research is required on detecting and controlling (eg using foam) geological faults or caprock flaws, especially for converted aquifers.

1. INTRODUCTION

Underground gas storage experience dates back to the beginning of the last century, with the first underground natural gas storage (UNGS) reservoir beginning operation in 1915 in Ontario, Canada. Since then, growth in the number of storage reservoirs progressed slowly at first, but eventually increased significantly to over 630 UNGS facilities around the world. Most of the UNGS facilities are found in the USA (66%) and are former oil and gas reservoirs (83%), followed mainly by converted aquifer and caverns.

Experience from the oil and gas industry can be used directly for GCS and so far successful GCS has been demonstrated in the Sleipner field (Norway), where CO_2 from production is injected in a saline aquifer beneath the Sleipner West natural gas reservoir (Figure 1.1).

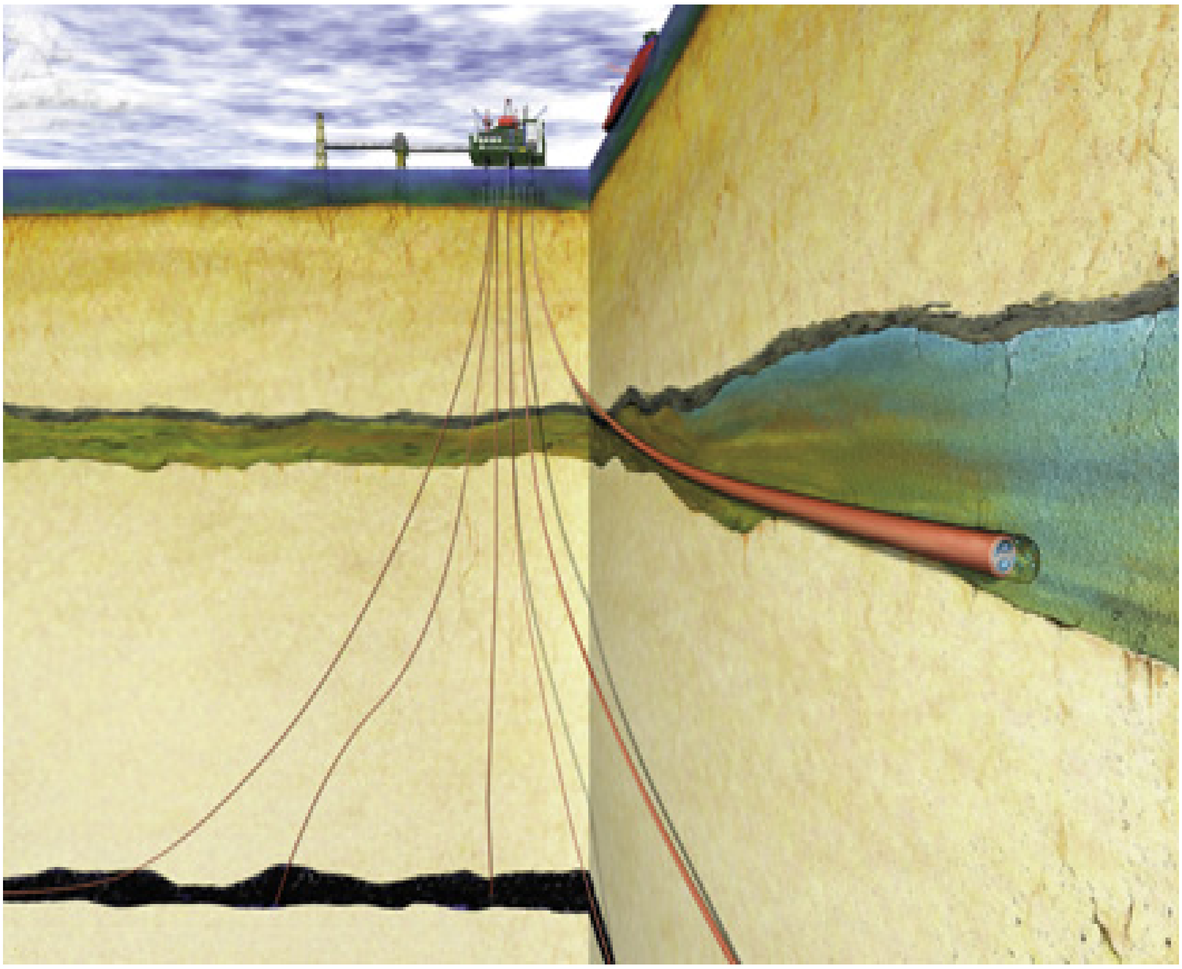
The purpose of this study was to gather information on regulatory processes and operational practices from the natural gas storage industry, for depleted reservoirs and converted aquifers, and the associated UNGS facilities, and to assess their applicability to CO_2 geological storage.

The scope of work and base data for the report is given in Section 2. The technical assessment is presented in Section 3.

Conclusions and recommendations are presented in Section 4 and references are given in Section 5.

The appendices are contained in Section 6.

Figure 1.1: GCS in the Utsira sand aquifer, beneath the Sleipner West gas reservoir (Statoil, Geotimes Mar03)[154]



2. SCOPE OF WORK AND BASE DATA

2.1 Scope of work

The scope of work is given in IEA/CON/04/109, which is included in Appendix A and is summarised below.

- Review characteristics of global UNGS facilities.
- Review UNGS legislation from mainly the USA, Canada and northern Europe. Highlight regional differences and assess their applicability to geological CO_2 storage (GCS).
- Review publicly available information on UNGS leakage incidents. Identify and assess leakage causes, consequences and remediation actions taken. Derive an UNGS leakage frequency and discuss relevance to GCS.
- Review current practices and constraints for UNGS site selection and assess their relevance to GCS.
- Review current operating practices for inventory monitoring, verification, leakage detection and remediation and assess their relevance to GCS.
- Assess relevant UNGS design and operational aspects and assess their relevance to GCS.

2.2 Base data

Information used in this study was obtained from:

- Discussions with UNGS consultants, UNGS operators, legislators and government agents (see Section 5.2).
- Information supplied by IEA Greenhouse Gas R&D Program (IEA GHG).
- Various studies on natural gas storage and GCS (see Section 5.1).
- Information presented in 'The future development and requirements for underground gas storage in the UK and Europe' conference, organised by the Geological Society and held in Aberdeen, Scotland (19-20 October 2004).

3. TECHNICAL ASSESSMENT

Underground natural gas storage can be defined as the storage of large quantities of natural gas in formations of porous rock at various depths beneath the surface of the earth.

The main reasons for developing UNGS facilities are:

- Store gas during low demand periods (traditionally during summer months) and use it during peak gas demand (eg, winter months). Depleted hydrocarbon reservoirs and aquifers are mainly used for this type of storage.
- Protect against short term failure of the gas supply system (eg, long-line transportation system failure).
- Meet the regulatory obligation to ensure supply reliability at the lowest cost to the ratepayer by maintaining specific levels of gas inventory.
- Avoid imbalance penalties and help contain gas price volatility and maintain orderly gas markets.

The main types of UNGS reservoirs are depleted oil and gas reservoirs, converted aquifers, coal mines and salt caverns. Only oil and gas reservoirs and converted aquifers will be discussed in this study, as coal mines and salt caverns are of relatively small volume for storage of large CO_2 volumes and the cost of mining is high.

3.1 UNGS database review and GCS applicability

The review of UNGS facilities is based on the International Gas Union (IGU) UNGS database[1]. The IGU database contains detailed information on worldwide natural gas facilities and includes a geo-referenced UNGS world map.

Based on information from the IGU database, the worldwide working gas volume is approximately 340 billion m^3 and is operated in over 630 UNGS facilities. The greater part of the working gas volume is installed in America and Eastern Europe (Figure 3.1). The United States of America has the most UNGS facilities, followed by Canada, Germany and Russia (Figure 3.2). Most of the working gas volume is installed in UNGS facilities in depleted oil and gas reservoirs (83.5%), followed by aquifers (12.6%), salt caverns (3.8%) and abandoned mines and rock caverns.

A review of the main oil and gas and converted aquifer UNGS facilities in the USA, Canada, UK, Netherlands, Germany, France and Italy is presented below and the main findings are summarised in Table 3.1.

3.1.1 UNGS facilities review

USA

UNGS experience in depleted oil and gas reservoirs in the USA dates back to 1916 and the first converted underground gas storage aquifer was commissioned in 1946. Most of the gas storage facilities in the USA are in depleted reservoirs (334 UNGS reservoirs) and are located close to the large consumption centres. Also, there are 50 aquifers mainly in the Midwestern

United States, which have been converted to UNGS reservoirs. UNGS reservoir depths range from 50m to 4,000m. Approximately 40% of the depleted reservoirs and 20% of the converted aquifers are deeper than 800m depth. Storage rock type is mainly sandstone for both types of UNGS reservoirs.

Figure 3.3 illustrates the ratio of maximum storage pressure to initial pressure (at datum level) for depleted reservoirs and converted aquifers UNGS facilities in the USA and the rest of the world.

The majority of the depleted reservoirs operate below the initial reservoir pressure (ie, storage pressure to initial storage pressure ratio <1), followed by a significant number operating at 1.5 times the original reservoir pressure. Only a few UNGS depleted reservoirs exceed original pressure by 80% to 90% (ie, ratio ≈ 1.8 - 1.9). The majority of the converted aquifers operate at storage pressure ratios between 1 and 1.3 and only a few approach a ratio of 1.6.

The maximum working gas volume for depleted reservoirs and converted aquifers, ranges from 0.06 million m^3 to 2,718 million m^3 and the number of storage wells range from 1 to 630 storage wells per UNGS facility. 80% of the oil and gas reservoirs and almost all (98%) of the aquifers have observation wells, with aquifers having the greatest number of observation wells (eg, 163 observation wells at Herscher Galesville aquifer – Illinois).

No information could be obtained on the type of seismic and maximum pressure approval methods used in depleted reservoirs and aquifers.

Canada

UNGS experience in Canada dates back to 1915, when the first underground natural gas storage reservoir began operation in Ontario. There are 34 depleted oil and gas UNGS facilities in Canada and no aquifers. Reservoir depths range from 70m to 1,400m and only 15% of the UNGS reservoirs are deeper than 800m. Rock type is mainly Guelph sandstone and carbonate. The majority (Figure 3.3) of the UNGS facilities exceed the initial reservoir pressure (ie, ratio >1), with a significant proportion approaching 1.5 times the original pressure. Only a few UNGS facilities exceed original reservoir pressure by 80%. The maximum working gas volume ranges from 8 million m^3 to 2,633 million m^3 and the number of storage wells ranges from 4 to 33 wells per UNGS facility. 94% of the UNGS facilities have observation wells with 1 to 20 observation wells per facility.

No information was provided on the type of seismic and maximum pressure approval methods used.

UK

Rough was the first UNGS facility (offshore depleted reservoir) in the UK, commissioned in 1985. There is also Hatfield Moors UNGS depleted reservoir, but no aquifers. The Rough and Hatfield Moors reservoirs are 2,790m and 440m deep, respectively. Formation pressure information for the Rough field indicates that the maximum allowable storage pressure is slightly above (ratio ≈ 1.1) the initial reservoir pressure. The maximum working gas volume ranges from 120 million m^3 to 2,755 million m^3 for the Hatfield Moors and Rough field respectively. Available information from the Rough field indicates that there are 30 storage wells and no observation wells and the rock type is sandstone.

No information was provided on the type of seismic and maximum pressure approval methods used.

Netherlands

There are three UNGS reservoirs in the Netherlands and no aquifers. All three UNGS facilities were commissioned around the same time, in 1997.

UNGS reservoir depths range from 2,540m to 3,200m and the storage rock type is mainly sandstone. UNGS facility pressures in Netherlands do not exceed initial reservoir pressure (Figure 3.3). The maximum working gas volume ranges from 250 million m^3 to 3,000 million m^3 and the number of storage wells ranges from 6 to 8 wells per UNGS facility. Almost all UNGS facilities have observation wells, with 1 to 4 observation wells per facility.

Mainly 2D, 3D and improved seismic methods are used; however, no information on the type of maximum pressure approval methods used is provided.

Germany

Lehrte and Rehden were the first UNGS facilities (depleted reservoirs) in Germany, commissioned in 1952 and Hähnlein was the first converted aquifer UNGS facility, commissioned in 1960. In total there are 15 depleted reservoirs and 7 converted aquifers. Reservoir depths range from 340m to 2,930m. Approximately 67% of the depleted reservoirs; and only 14% of the converted aquifers are deeper than 800m depth. Storage rock type is mainly sandstone.

The majority (Figure 3.3) of the depleted reservoir UNGS facilities exceed initial reservoir pressure[*] by 20% (ie, ratio of 1.2), with only one UNGS reservoir approaching a ratio of 1.4. Aquifer reservoir pressures for the majority of the UNGS facilities are approaching a ratio of 1.1, with two aquifers exceeding 1.5.

The maximum working gas volume ranges from 30 million m^3 to 4,200 million m^3 and the number of storage wells ranges from 3 to 44 wells per UNGS facility. Most (≈ 80%) of the depleted reservoirs and all of the converted aquifers have observation wells, with aquifers having the greatest number of observation wells (18 observation wells at Buchholz aquifer UNGS facility).

Seismic methods used include 2D and 3D, but for a high number of UNGS facilities no seismic surveys are used. Maximum pressure is calculated mainly by capillary threshold pressure tests, empirical methods and fracture gradients.

[*] Caprock integrity is enhanced by salt layers, allowing overpressurisation of the majority of the UNGS reservoirs in Germany[155].

France

France has twelve natural aquifers that have been converted to gas storage reservoirs and no depleted reservoirs. Aquifer reservoir depths range from 395m to 1,140m. Approximately 33% of the aquifers are deeper than 800m depth[155]. Rock type is mainly sandstone and the storage pressure of the majority of the converted aquifers ranges between 20-40% above the aquifer initial pressure (Figure 3.3). Only two converted aquifers approach 1.5 times the original aquifer pressure. The maximum working gas volume ranges from 210 million m^3 to 3,780 million m^3 and the number of storage wells ranges from 10 to 97 wells per UNGS facility. All reservoirs have observation wells and SSSVs[155].

Mainly 2D and 3D seismic methods are used and maximum pressure is calculated, for the majority of the UNGS facilities, by a combination of fracture gradient calculations, capillary threshold pressure tests and empirical methods. There is insufficient information on the first aquifer conversions, however, the Lussagnet and Beynes aquifers were commissioned in 1956.

Italy

There are ten UNGS, depleted oil and gas reservoirs and no aquifers. Reservoir depths range from 820m to 1,400m and the rock type is mainly sandstone. No UNGS facility in Italy exceeds initial reservoir pressure (Figure 3.3). The maximum working gas volume ranges from 694 million m^3 to 3,529 million m^3 and the number of storage wells ranges from 8 to 54 wells per UNGS facility. Almost all the facilities have observation wells, with 2 to 16 observation wells per facility.

Mainly 2D and 3D seismic methods are used and there is no information on the type of maximum pressure approval methods used. Cortemaggiore was the first UNGS facility in Italy, commissioned in 1964.

3.1.2 UNGS facilities review from a GCS perspective

Information contained within the UNGS database indicates that:

- The majority of the depleted reservoirs in USA and Canada are less than 800m deep. However, there is still a significant number of depleted UNGS reservoirs deeper than 800m.
- The majority of the depleted UNGS reservoirs in Europe are deeper than 800m, especially in the Netherlands and Italy, where all depleted reservoirs are deeper than 800m.
- Few countries have developed aquifers and only a small percentage of aquifers across the world are deeper than 800m.
- The majority of the depleted reservoirs (eg, 80% in the USA, 84% in Italy) and almost all the aquifers have observation wells.
- The maximum storage pressure of almost all depleted UNGS reservoirs in Canada and a large proportion in the USA exceed the reservoir discovery pressure, where as in the rest of the world only a few depleted reservoirs exceed reservoir discovery pressure.

- The majority of the aquifers around the world operate between 20% and 40% above the aquifer formation pressure, with only a few aquifer UNGS facilities operating in excess of 50% above the aquifer formation pressure.
- From the information available, the majority of UNGS operators use either no seismic or 2D seismic methods and the main techniques used to calculate maximum reservoir pressure are fracture gradients, capillary threshold pressure tests empirical approaches.

Therefore, from a GCS point of view, experience from existing UNGS facilities indicates the following:

- In America, the majority of the depleted reservoirs and converted aquifers are less than 800m deep; therefore competition for deep geological space is less likely.
- In Europe, the majority of the depleted reservoirs are deeper than 800m; however, the majority of the converted aquifers are less than 800m deep. Only a few deep aquifers have been developed and therefore competition for geological space is more likely for depleted reservoirs than for aquifers.
- Competition for geological space between UNGS and GCS is considered to be unlikely in North America but is possible onshore in Europe.
- The majority of the depleted reservoirs and almost all converted aquifers have observation wells, indicating operators' preference for observation wells for reservoir monitoring.
- Countries with a longer experience in underground gas storage (ie, USA and Canada) operate the depleted UNGS reservoirs above reservoir discovery pressure.
- The majority of the UNGS aquifers operate between 20% and 40% above the aquifer formation pressure, which could be a good indication for GCS projects.
- From the little information available, UNGS operators do not generally use seismic monitoring, whereas in the first GCS project in Sleipner field, it has proven to be extremely useful for monitoring CO_2 movement. Offshore seismic monitoring is not as expensive as onshore and advanced (eg, 3D) seismic monitoring could be beneficial for GCS projects.
- Similarly to UNGS projects fracture gradients, capillary threshold pressure tests and also empirical approaches could be used to calculate maximum reservoir pressure.

Table 3.1: Summary of geological and operating aspects of UNGS facilities

Oil And Gas Reservoirs		UK	France	Germany	Netherlands	Italy	USA	Canada
Number of sites		2	0	15	3	10	334	34
Off Shore	UGS no.	1 (Rough)						
Depth	Min Depth (m)	440		340	2540	820	52	70
	Max Depth (m)	2790		2930	3200	1400	3962	1402
	% >800m	50%		67%	100%	100%	39%	15%
Storage formation (Note 1)	Mainly	Permian sandstone		Mixture	ROSL	Mixture	Mixture	Guelph
Storage lithology	Mainly	Sandstone		Mixture	Sandstone	Sandstone	Sandstone, Carbonate	Carbonate, sandstone
Original reservoir pressure	Range (bar)	235 (Rough only)		32-390	327-393	116-180	5-552	8.4-209
Maximum allowable storage pressure	Range (bar)	259 (Rough only)		36-460	327-393	116-180	6-483	8.4-220
Installed Max Working Gas Volume	Range (mill m^3)	120-2755		40-4200	250-3000	694-3529	0.06-2718	8-2633
No of storage wells	Range	30 (Rough only)		3-44	6-8	8-54	1-630	4-33
No of observation wells	Range	-		1-17	1-4	2-16	1-163	1-20
% of reservoirs with observation wells	%	-		80	67	84	80	94
% of reservoirs with SSSV	%	None (Rough only)		67	67	67	-	-
Seismic applied		-		2D/3D and no seismic	2D/3D/ improved seismic	2D/3D seismic	-	-
Pmax approval		-		All Methods	-	-	-	-

Aquifers		UK	France	Germany	Netherlands	Italy	USA	Canada
Number of sites		0	12	7	0	0	50	0
Off Shore	UGS no.							
Depth	Min depth (m)		395	500			102	
	Max depth (m)		1140	2100			1219	
	% >800m		33%	14%			20%	
Storage formation (Note 1)	Mainly		Mixture	Mixture			Mixture	
Storage lithology	Mainly		Sandstone	Sandstone			Sandstone	
Original reservoir pressure	Range (bar)		40-125	52-230			9-113	
Maximum allowable storage pressure	Range (bar)		49-160	54-315			10-140	
Installed Max Working Gas Volume	Range (mill m^3)		210-3780	30-1000			2-1674	
No of storage wells	Range		10-97	5-18			3-153	
No of observation wells	Range		9-15	2-18			1-163	
% of reservoirs with observation wells	%		100	100			98	
% of reservoirs with SSSV	%		100	50			-	
Seismic applied		-	2D/3D seismic	2D seismic			Limited info: 2D/ 3D	
Pmax approval		-	All methods	Mainly Capillary Threshold Pressure Tests			Limited info: fract grad, capillary thresh, empirical	

Note 1: Storage formation refers to the name/location of the formation as stated in the IGU database. They are not types of storage formation.

Figure 3.1: Installed UNGS working gas volume per nation

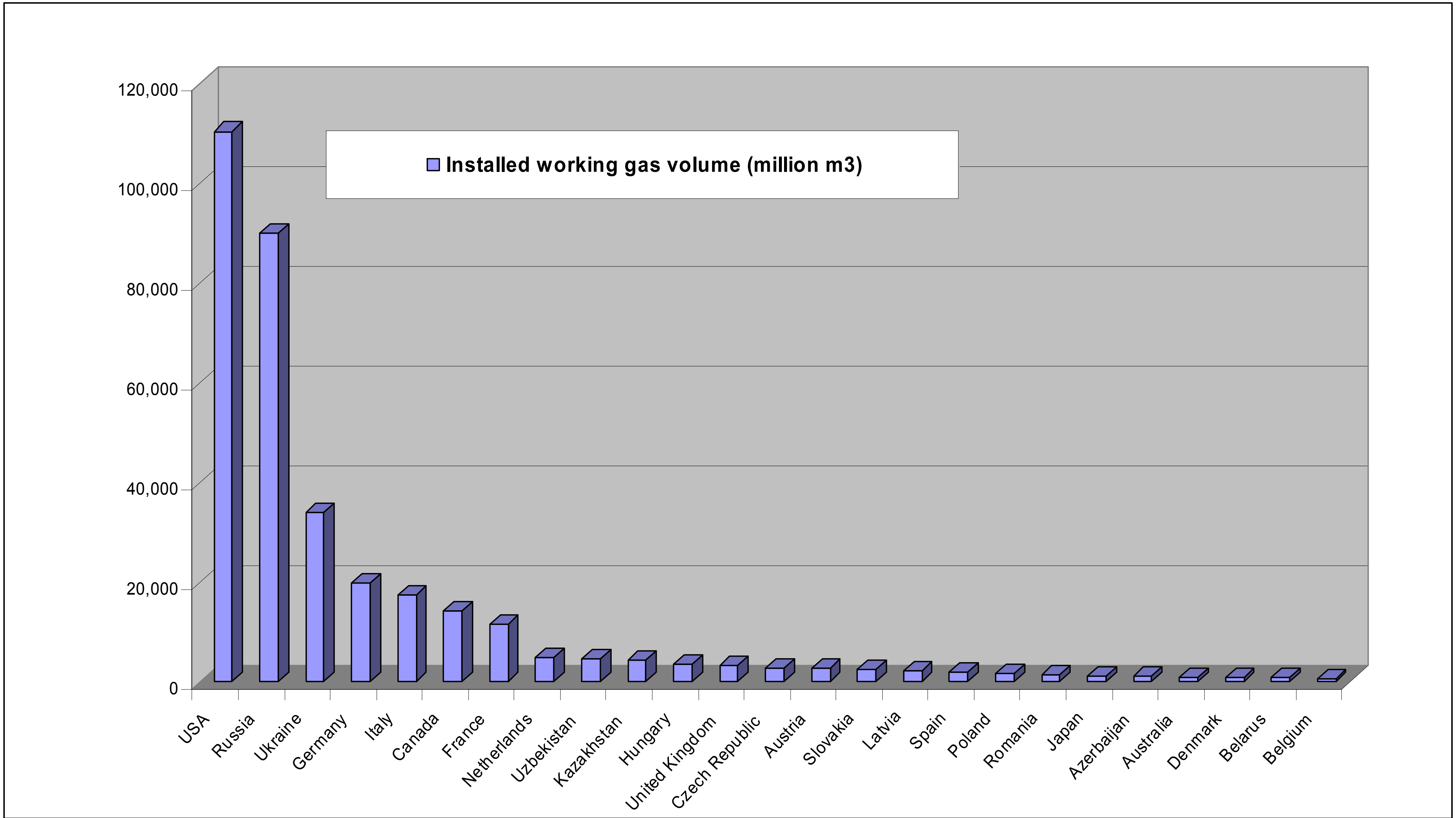


Figure 3.2: Number of UNGS facilities per nation

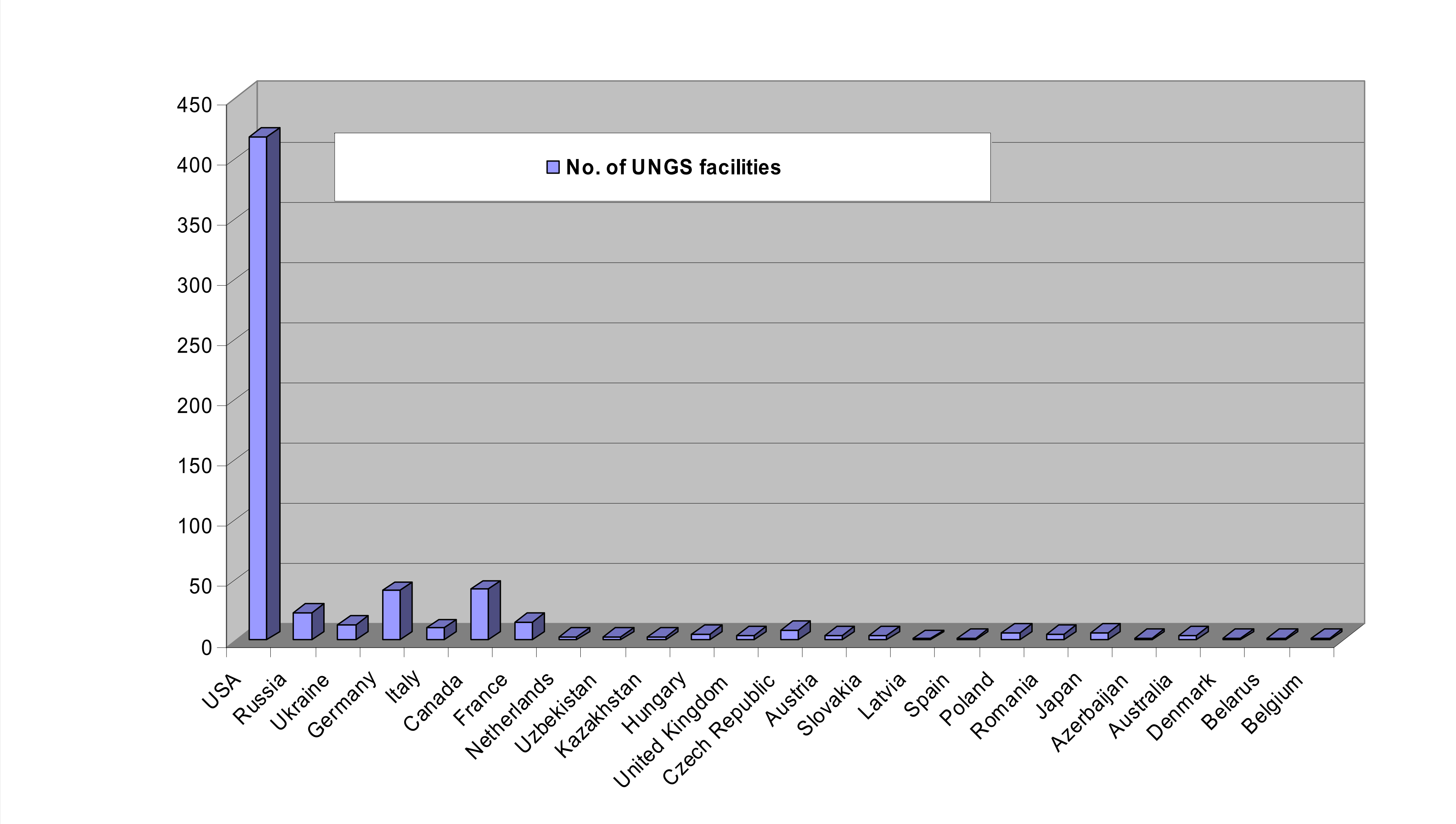
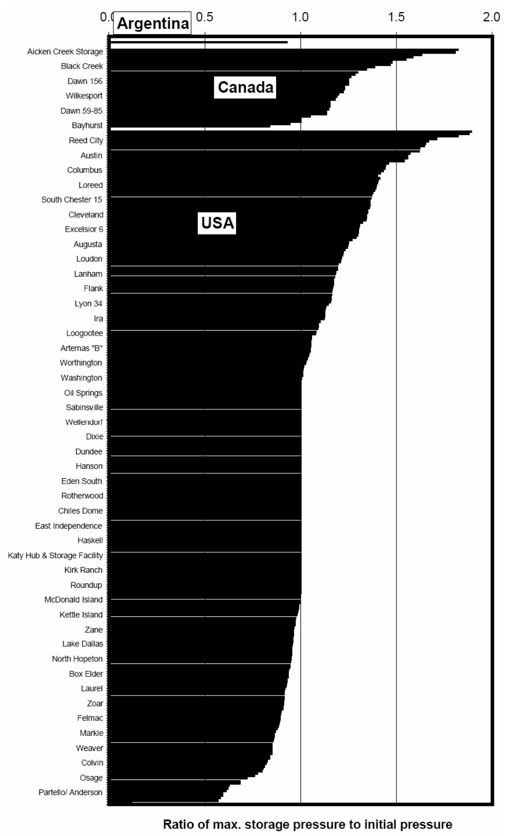
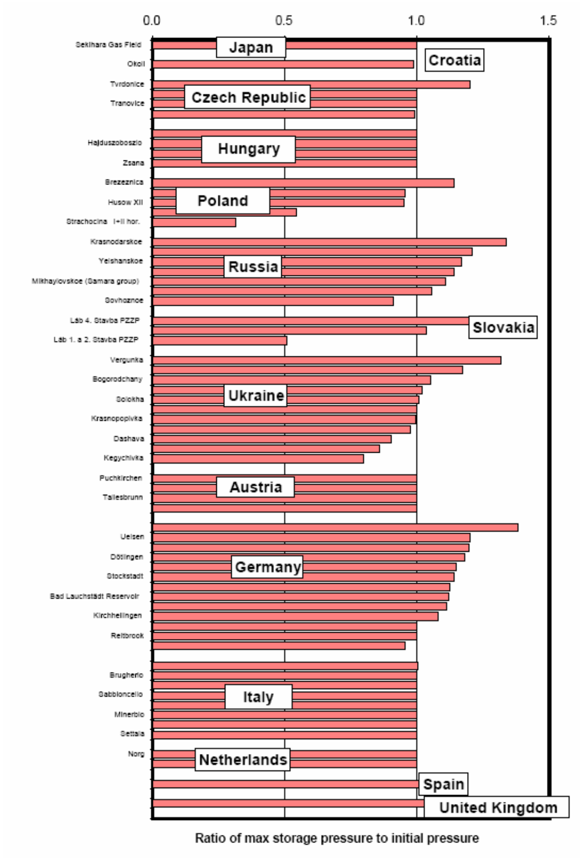


Figure 3.3: Maximum to initial storage pressure in depleted reservoirs (America and world excluding America); and aquifers (International Gas Union Jun03)[1]

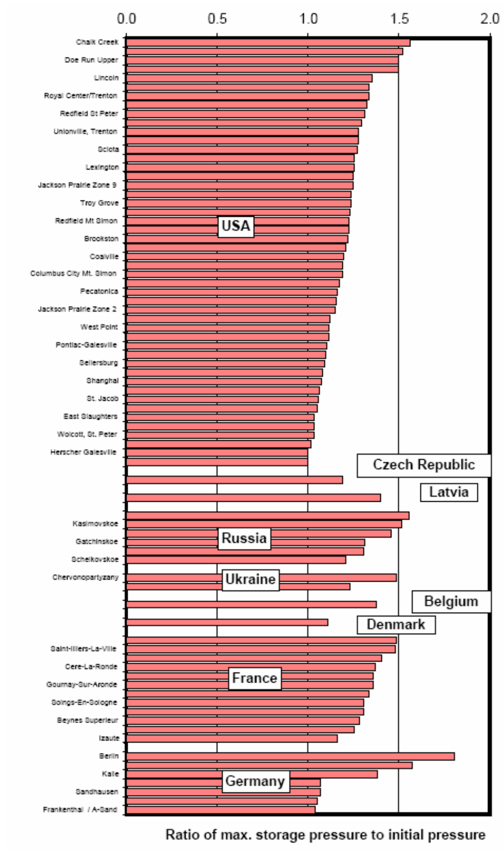
Max. storage pressure to initial storage pressure.
Depleted reservoirs
(North America)



Max. storage pressure to initial storage pressure.
Depleted reservoirs
(World excluding North America)



Max. storage pressure to initial storage pressure.
Aquifer storage



3.2 UNGS legislation and GCS relevance

The main regions from which UNGS specific legislation was studied are USA, Canada and Western Europe (ie, UK, Netherlands, Germany, France and Italy).

UNGS legislation was found to vary considerably between countries, as some countries have more prescriptive legislation than others. However, all relevant legislation studied essentially had some common aims such as protecting the environment, especially drinking water aquifers and also ensuring that no activities could affect public health and safety.

It should be noted that the use of the term 'legislation' has been generalised in this report to include also, regulations, guidance documents, applicable international treaties, etc.

3.2.1 USA

Underground injection in the USA is managed under the Underground Injection Control (UIC) program, and its main target is to safeguard underground sources of drinking water (USDW). The Environmental Protection Agency (EPA) has the main responsibility of protecting human health and safeguarding the environment. The key responsibility of the states is the protection of the environment, especially drinking water aquifers from injected fluids. The EPA has delegated to most states the regulation and monitoring of underground gas storage, including issuing permits.

A selection of interstate (federal) legislation that applies to UNGS facilities in the USA is provided below.

Interstate (Federal) legislation

2004 Model Oil and Gas Conservation Act (MOGCA)
The MOGCA covers efficient recovery of domestic oil and natural gas resources and aims to protect health, safety, property and the environment. The 2004 model is supplemented by the Model Underground Gas Storage Provisions. The provisions address the acquisition of property suitable for UNGS.

Safe Drinking Water Act (SDWA)
The SDWA aims to protect the quality of drinking water and also to regulate the underground injection of fluids through wells. Underground injection wells are regulated by the UIC program but mainly, which is mainly prepared by the states. The state's UIC program should meet, as a minimum, federal requirements.

Clean Water Act (CWA)
The 1972 CWA is the primary instrument that governs impacts on water, including 'pollution' from 'man-made' underground injection. A classification of injection wells is provided, where natural gas stored underground, falls under category II (see UIC program classification below).

Code of Federal Regulation – Underground Injection Control Program
Federal regulations (40 CFR. Part 144, 145, 147) state the minimum requirements for state UIC programs. The UIC regulations divide underground injection into the following five categories:

Class I: Deep injection of industrial wastes and hazardous wastes.
Class II: Injection of fluids produced during oil and gas development, natural gas underground storage, including CO_2 and brine used for enhanced oil recovery (EOR).
Class III: Injection for mineral extraction.
Class IV: Hazardous and radioactive injection.
Class V: All other wells not included in the above classes.

The relevant points of the UIC program are:

- Main purpose of the regulation is to protect the underground source of drinking water from contaminants, by regulating the five classes of injection wells, as described above.
- Owners/operators of injection wells should demonstrate financial responsibility in case of accidents. Acceptable indicators can be in the form of surety bonds (guarantees), letters of credit, trust fund, etc.
- Requirement to demonstrate that casing and cementing are adequate to prevent movement of fluid into or between underground sources of drinking water (USDW). The most relevant well classes to this study, are Class I and II. Class I wells must demonstrate that there will be no migration, ie, the injected waste will not leave the injection zone for 10,000 years. This analysis is very complex technically and sophisticated computer modelling of the hydro-geological data is required. Class II wells are typically oil and gas production, brine disposal and underground gas storage wells. Class II follow the same construction requirements as Class I wells, but they have less stringent permit requirements than Class I wells, making them less expensive. A summary of logs and tests required for Class I injection wells is given in Appendix B.
- The owner of the injection well is responsible for the mechanical integrity of the well until the well is properly plugged (with cement). Financial assurances are required to ensure that the owner will properly plug and abandon the wells.
- The operator should not exceed the maximum injection pressure, and should monitor underground water quality and potential gas migration. Injection wells should be monitored and tests should be performed to demonstrate well mechanical integrity, at least once every five years.
- An emergency permit for underground injection can be issued, if there is an imminent and substantial endangerment to public health, a substantial loss of oil and gas resources, or a substantial delay in production of oil and gas resources.
- Well class is determined by source and how the injected fluid is being used.
- 40 CFR 146.6 provides guidance to calculating the ZEI (zone of endangering influence), which is the 'cone of influence' surrounding the injection well, where increased pressures due to injection would be sufficient to cause fluid movement into a USDW. The ZEI is used to calculate the AOR (area of review) or empirical methods are used by states (eg, ¼ mile for Class II injections). All plugging and completion records within the AOR are examined to determine potential pathways for migration into USDW.

<u>Research and Special Programs Administration (RSPA) Pipeline Safety Regulations</u>
Hazardous liquids and natural gas pipeline safety regulations require operators of UNGS facilities to take preventative actions, including system safety analyses and take steps to minimise risk.

The movement of injected fluids in an USDW is explicitly prohibited in class I-III wells, mandating zero contamination. Review of federal requirements indicated that there are no federal requirements for observation wells, or even monitoring for detecting leakage (with the exception of some Class I wells).

2004 Model Underground Gas Storage Provisions (Interstate Oil and Gas Compact Commission)

All natural gas injected into underground reservoirs, shall at all times be the property of the injector. Surface owner can drill through a UNGS reservoir, if done according to the commission rules. If injected natural gas migrates to an adjoining property, which has not been acquired by the storage company UNGS; the owner of the surface/stratum shall be entitled to compensation for use or damage of the subsurface.

State specific legislation

A summary of relevant UNGS information from a selection of states in USA is provided below.

California

The following state regulations were reviewed:

- California Code of Regulations.
- California Laws of Conservation of Geothermal Resources.
- California Laws for Conservation of Petroleum and Gas.

Regulations require the following information for UNGS project approval:

- Characteristics of the caprock.
- Oil and gas reserves of storage zones prior to start of injection.
- List of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project.
- Proposed waste water disposal method.

Relevant information from the reviewed document has been extracted and tabulated below.

Table 3.2: Summary of relevant information for California

Cash bond	Cash bond or indemnity required. Liability of abandoned wells may be terminated when wells are properly abandoned to the satisfaction of the state supervisor.
Cementing	Wells shall be cemented to seal off fluids from contaminating freshwater zones. As a general guide the surface casing shall be cemented at a depth that is at least 10% of the proposed total depth, with a minimum of 200 feet. Intermediate casing may be required for protection of oil, gas and freshwater zones.
Plugging and	As a minimum for a cased hole the cement plug shall extend from at

abandonment	least 100 feet below the top of the zone to at least 100 feet above the top of the perforations, the top of a landed liner, the casing cement point, water shutoff holes, or the oil/gas zones, whichever is highest. A minimum of 200-foot cement plug shall be placed across all fresh-saltwater interfaces.
Monitoring	Information is required on the monitoring system/method to be utilised to ensure that fluid is confined to the intended zone.
Safety devices	Information on SSSV is required under 1724.9. Also Offshore Well Regulations (1747.2) state that all automatic wellhead safety valves shall be tested monthly for holding pressure.
Tubing/packer	Tubing/packer is required. Following initial mechanical integrity test the annulus of each well must be tested at least every five years.
Max allowable surface injection pressure	Step-rate tests are required to determine the maximum allowable injection pressure. Max allowable surface injection pressure shall be less than fracture pressure (step rate test to be conducted).
Observation wells	Reference is made to observation wells that may be required.
Ownership	Landowner should receive fees or royalty.
Environmental, other	Injection should be stopped if there is evidence of damage to life, health, property or natural resources, or loss of hydrocarbons. Article 5.5 (3315) states that depressurisation of reservoirs could lead to subsidence and that the only feasible method to arrest or ameliorate subsidence is by repressurising subsurface oil/gas formations.

<u>Texas</u>
The Railroad Commission of Texas, Oil and Gas Division regulates underground injection of fluids. The Texas Administrative Code was reviewed and the main relevant points have been tabulated below.

Table 3.3: Summary of relevant information for Texas

Cash bond	Cash bond required.
Cementing, plugging and abandonment	Production casing shall be a minimum of 100 feet in length and extend at least 50 feet above and below the base of the deepest usable quality water stratum. Operator's duty to properly plug a well ends when well is plugged in accordance to Commission requirements, up to the base of the usable quality water stratum. Cement plugs shall be set to isolate each productive horizon and usable quality water strata.
Monitoring, safety devices	UNGS facilities with gas storage wells located within 100 yards from a residence, commercial establishment and 'small, well-defined areas' and at each enclosed compressor site, should have gas detectors. Leak detectors should be integrated with the site's or remote control system warning system. However, gas storage wells used only for gas withdrawal are exempt from these requirements.
Tubing/packer	Tubing/packer required.
Max allowable	Permit is required to increase pressure above permitted pressure.

surface injection pressure	
Observation wells	Not stated.
Ownership	Ownership of minerals initially resides with the owner of the surface land, but normally mineral rights are sold and are separated from the surface owner rights.
Other	Gas storage wells should be cased and wellhead assemblies shall be used on wells to maintain surface control of the well. Each gas storage well shall be pressure tested at least once every five years.

Michigan
No specific UNGS regulations were identified. UNGS operations are covered under:

- Michigan's Oil and Gas Regulations – Part 615, Supervisor of Wells.
- UNGS leases are covered under the 'Rules for the Underground Gas Storage Leases on State Lands'.

Part 615 is the primary Michigan law regulating mainly, drilling and operation of oil and gas wells and also gas storage wells. The main relevant points are summarised below.

Table 3.4: Summary of relevant information for Michigan

Cash bond	Cash bond or indemnity required
Cementing, plugging and abandonment	A cement plug is required to be set at the base of the surface casing. The surface plug should be a minimum of 200ft in length or contains 50 sacks of cement. A program is in place to inventory, prioritise and plug abandoned oil and gas wells and to remediate abandoned sites. The main source of funding for an abandoned site remediation is the Orphan Well Fund and Part 201 bond funds.
Max allowable surface injection pressure	Surface injection pressure should not exceed the pressure determined by the following equation: $Pm = (fpg – 0.433\ sg)d$, where fpg is the fracture pressure gradient, sg is the specific gravity and d is the injection depth.
Ownership	Ownership of minerals initially resides with the owner of the surface land, but normally mineral rights are sold and are separated from the surface owner rights.
Other	- A requirement exists for conducting a 5-year mechanical integrity tests of casing. - Specific rules exist for drilling to strata beneath gas storage reservoirs, eg, drilling though the gas storage zones is allowed only when gas storage reservoir pressure exerts a pressure gradient of not more than 0.50 psig/ft of true vertical depth to the top of the gas storage zone.

Kansas

The Underground Porosity Gas Storage Regulations were reviewed. The regulations generic requirements for UNGS operations are summarised below.

Table 3.5: Summary of relevant information for Kansas

Cash bond	Cash bond or indemnity required.
Plugging and abandonment	Wells should be plugged and abandoned in a manner that prevents the movement of gas or fluids from the gas storage reservoir.
Monitoring	Includes monthly wellhead pressure monitoring, report of potential leaks and gas volume metering.
Max allowable surface injection pressure	Maximum injection rate and pressure does not exceed the fracture gradient and will not initiate fractures through the overlaying state or cause gas leak. Maximum allowed storage reservoir pressure should not exceed 75% of the fracture gradient as determined by a step rate test or as calculated by a licensed engineer. However, higher operating pressures may be allowed upon written application.
Environmental, safety	No gas storage shall be permitted in any underground porous stratum with chloride levels less than 5,000 mg/l. Safety, emergency plan, gas leaks reporting, gas alarms and permit to operate required.
Other	UNGS wells shall demonstrate mechanical integrity (required every 5 years) and new wells shall be completed with tubing and packer.

South Carolina

The Underground Injection Control Regulations were reviewed. The regulations state some generic requirements for UNGS operations and are summarised below.

Table 3.6: Summary of relevant information for South Carolina

Cash bond	Cash bond or indemnity required.
Cementing	Injection wells shall be cased and cemented.
Plugging and abandonment	- Placement of cement plugs shall be by the balance method, the damp bailer method, the two plug method or an alternative method approved by the Department. - Wells to be abandoned shall be in state of static equilibrium with the mud weight equalised top to bottom and demonstration is required that wells have been plugged is such manner which will not allow movement of fluids.
Monitoring	- Monitor of the annulus pressure or pressure test to determine absence of any leaks. For UNGS facilities, field or project basis monitoring is required rather than individual injection well monitoring. Monitoring of injected fluids and observation of injection pressure is required. - Temperature or noise log to determine absence of fluid measurement into underground drinking water.
Max allowable surface injection pressure	Injection pressure should not exceed reservoir fracture pressure.

Other	Demonstration of mechanical integrity at least once every five years is required.

Illinois

Part 240 - The Illinois Oil and Gas Act was reviewed, which includes Sub-part R – Requirements in Underground Gas Storage and for Gas Storage and Observation Wells. The main relevant points are summarised below.

Table 3.7: Summary of relevant information for Illinois

Cash bond	Cash bond or indemnity required.
Cementing	Surface casing shall be set to a depth of at least 100 feet or 50 feet below the base of freshwater zone and should be cemented in place. Production casing shall be set and cemented in place (minimum 250 feet above shallowest permitted injection interval).
Plugging and abandonment	Detailed plugging procedures are included for producing interval and surface plug.
Tubing/packer	Injection shall be through tubing and packer.
Max allowable surface injection pressure	Maximum injection pressure (MIP) should be calculated in accordance with the following formula: MIP = (0.8 – (0.433 x Specific Gravity)) x Depth – 14.7.
Other	Internal mechanical integrity test shall be performed once every 5 years.

Florida

The Regulation of Oil and Gas Resources and Conservation of Oil and Gas, Florida Administrative Code – Chapters 62C-25 to 62C-30, were reviewed and the main, relevant points are summarised below.

Table 3.8: Summary of relevant information for Florida

Cash bond	Cash bond or indemnity required.
Cementing	Surface casing shall be set below the deepest USDW and cemented to the surface. Minimum surface casing depth is based on well depth, eg, for well depth of up to 7,000 feet, surface casing should be 1,500 feet. For production/injection, casing at least 1,500 feet above the uppermost producible hydrocarbon zone is required.
Plugging and abandonment	Cement plugs shall be placed 200 feet below and above of the deepest USDW, or any hydrocarbon bearing zone within 5 miles of the wellbore.
Safety devices	Muster valve is required for shut in surface pressure in excess of 1,000 pounds per square inch and all wellheads should be equipped with an automatic safety valve and be surrounded by at least three gas detectors.
Tubing/packer	Tubing and packer should be set no more than 100 feet above the top of the perforated formation.
Max allowable surface injection	Upper limit of allowable injection pressure should be specified.

pressure	
Environmental	No gas storage should be approved if total dissolved solids of the formation do not exceed 10,000ppm or 5,000ppm of chloride.
Other	Mechanical integrity of the casing and tubing should be tested yearly.

3.2.2 Canada

The following documents were studied:

- Gas Distribution Act.
- Z341-98, Storage of Hydrocarbons in Underground Formations (General Instruction) Canadian Standards Association (CSA).
- Canada Oil and Gas Drilling and Production Regulations.
- Canada Oil and Gas Production and Conservation Regulations.
- Underground Hydrocarbons Storage Act and Underground Hydrocarbons Storage Regulations (Nova Scotia).
- Canadian Environmental Assessment Act.
- Gas Distribution Act, 1999 (New Brunswick).
- Canada Oil and Gas Operations Act.
- Oil, Gas and Salt Resources of Ontario (Provincial Operating Standards).

The main source on UNGS guidance in Canada is the CSA Standard Z341-98[9], which is directly endorsed by most of the provinces in Canada. Z341 treats both aquifers and reservoirs equally and calls for assessment of all existing wells within 1km of the subsurface perimeter of the storage zone, especially the integrity of wellbores penetrating the reservoir. Detailed studies are required in order to assess the integrity of the geological formation.

The Environmental Protection Act clearly states that, fluids which are classified as 'liquid industrial waste' (including stimulation fluids), shall not be injected underground, unless a permit is issued.

Table 3.9: Summary of relevant information for Canada

Cash bond	Cash bond or indemnity required.
Cementing, plugging and abandonment	Production casing should be cemented to at least 100m above the shallowest hydrocarbon-bearing zone and to surface from a depth of not less than 25m below the deepest usable ground water aquifer. Well abandonment design shall ensure that the storage area is completely isolated form all other porous (including fresh water aquifers) or hydrocarbon bearing horizons. Cement should have a minimum strength of 3500 kPa after curing for 48 hrs.
Monitoring	Inventory verification requirements include hydrocarbon volumetric flowrates and pressures.
Safety devices	A subsurface safety valve (SSSV) is required for offshore installations. For onshore facilities, a SSSV is required if the site is near (100m) dwellings or sensitive areas, or there is H_2S in the gas.
Max allowable surface	Maximum operating pressure should not exceed 90% of the fracture pressure of caprock formation. For disposal wells the subsurface

injection pressure	pressure at the midpoint of the disposal zone shall not exceed 75% of the formation fracture pressure at that depth during the injection of oil field fluid, except during well stimulation[123].
Ownership	An underground UNGS site is property separate from the soil and vested in the Crown in the right of the Province. Also oil and natural gas is property separate from the soil (New Brunswick). The provinces own the mineral/pore space and some form of compensation is paid to land owner (eg, Nova Scotia and Ontario).
Observation wells	Observation wells are required to monitor migratory paths, spill points and permeable zones above or adjacent to the storage zone.
Other	Injection/storage permits and license are required for UNGS facilities.

3.2.3 Europe

In Europe the main standard for design and operation of UNGS facilities is EN 1918:1998[11]. EN 1918:1998 has five parts, which cover aquifer storage, oil and gas reservoirs, salt and lined rock caverns and also UNGS surface facilities.

The main aspects specific to oil and gas (depleted) reservoirs and aquifers are discussed below.

- The standard states more extensive requirements for aquifer UNGS facilities, compared to depleted reservoirs, because aquifer integrity has not been proven. The standard requires general geological and seismic study to assess depth and thickness of the reservoir and also exploration drilling to assess gas tightness of caprock.
- The standard states that depleted reservoirs are preferred for underground gas storage facilities, because of their proven integrity. However, despite the proven containment of oil and gas reservoirs the standard requires detailed evaluation of the reservoir, such as assessment of trapping mechanism, integrity of existing and abandoned wells, etc.
- Maximum operating pressure is required to be determined in order to minimise risk of mechanical failure, gas penetration through the caprock and also uncontrolled lateral spread of gas.
- Monitoring requirements for oil and gas reservoirs are limited to injection/withdrawal rates, material balances and simulations studies to monitor for leakage. For aquifers the monitoring standards are more extensive and require monitoring of gas for vertical leakage, by monitoring upper aquifers and logging wells.
- Tubing/packer and SSSVs are required.

UK

The following regulations and guidelines were reviewed.

- A guide to the Borehole Sites and Operations Regulations 1995.
- A guide to the well aspects of the Offshore Installations and Wells (Design and Construction, etc) Regulations 1996.
- Control of Major Accident Hazards Regulations 1999 (England and Wales).
- Groundwater Regulations 1998.
- Water Resources Act, 1991 and Groundwater Regulations, 1998.
- EU Water Framework Directive, 2000.

- Pollution Prevention and Control Act 1999 (and Regulations 2000).
- Petroleum Law, 1998 (Decommissioning of Offshore Installations and Pipelines).
- The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001.
- Offshore installations (Safety Case) Regulations 1992.
- Guidelines for the Suspension and Abandonment of Wells, July 2001.

No UNGS specific legislation was identified, however some relevant points from the sources above are:

- Well control equipment and gas alarms are required (set at 25% LEL).
- Bond and guarantee is required.
- The submission of an abandonment program for offshore installations, including environmental impact assessment study, is required.
- Well Abandonment Program requires that all practicable steps have been taken to: control flow and escape of hydrocarbons, prevent damage to adjoining strata, isolate all permeable formations from one another, prevent possible crossflow and contamination of aquifers and abandon wells in efficient and workmanlike manner.
- A cement column of at least 100ft of good cement is considered to constitute a 'permanent barrier'. Generally, where possible, 500ft plugs are set. Where discrete permeable zones are less than 100ft apart, then a 100ft column of good cement below the base of the upper zone should suffice, where practical. For a cased hole to constitute a permanent barrier, the annuli should have good cement positioned opposite the cement plug in order to achieve full lateral coverage of cement in the well.
- The persons who own an installation or pipeline at the time of its decommissioning will normally remain the owners in perpetuity (Petroleum Act, 1998). A post-decommissioning survey is required, especially for monitoring levels of hydrocarbons, heavy metals and other contaminants. Any claims for compensation by third parties, from damage caused by any remains will be a matter for the owners and the affected parties.
- In the DTI 'Guidelines for the Suspension and Abandonment of Wells' it is stated that the government recognises that, in the longer term, ensuring that there continues to be someone with liability for the remains of any installations or pipelines could present difficulties, particularly, if companies cease to exist. Also, it is indicated that the Government will be willing to consider an appropriate insurance-based arrangement to address residual liability.
- Exploration and certain operation activities are subject to environmental impact studies.

Netherlands

The following documents were reviewed.

- Mining Act of the Netherlands 2003.
- Mining Decree.
- Mining Regulations.
- Environmental Management Act 2004. Gas storage is subject to the Wet bodembescherming (Law to protect the subsoil).

Regulations for surface installations differ for onshore and offshore facilities. The Environmental Management Act deals with onshore, surface facilities. The requirements for the Environmental Licence have to be decided by the authorities and are not fixed. Offshore installations fall fully under the new Mining Act. In general no Environmental Impact Statement is required for the aboveground parts of a facility. Health, safety and environmental aspects of underground activities are mainly subject to the Environmental Management Act and the new Mining Decree.

The Mining Act and Mining Decree specify the following:

- A storage plan is required, which should include an analysis of the risks involved and measures taken to prevent or minimise the risks. The storage plan must be approved by the government.
- Environmental impact assessment is required.
- Environmental and disaster control plan (to be revised every 5 years).
- A risk survey concerning soil movement and soil tremors as a result of storage.
- Guarantee fund is required.

For the decommissioning of wells and boreholes the following are required:

- The plug is tested by means of a weight of at least 100kN, or a pressure of at least 50bar for 915 minutes.
- In each annulus of a well a plug must be installed over a length of at least 100m towards the surface, starting at the shoe of the second-last casing.
- If the decommissioning well crosses a reservoir, whose contents may possibly escape to the surface, parallel cement plugs of at least 100m must be set both in the well and in the annuli at the same depth as the plug which is positioned closest to the reservoir.
- On top of a mechanical plug, which may be in contact with a corrosive medium or plugs a high-pressure reservoir, a cement plug of at least 50m must be placed.

The Mining Act stipulates that the concession holder is the sole owner of the stored substance. The Dutch Civil Code stipulates that the landowner is also the owner of the cavity. However, the landowner will have to permit its use by others under the Mining Act, if the use is so far below the surface that he has no interest in opposing such use. The Mining Act states that the landowner must permit mining activities (storage of substances) in so far as these activities take place at a depth of more than 100 metres without prejudice to the entitlement for compensation for any damage that is caused by these activities (eg, soil movement due to underground storage).

The Mining regulations prescribe monitoring during operational phase, including some limiting time after the abandonment of the site (eg, up to 30 years) for monitoring for subsistence due to hydrocarbon production[74].

Germany

The mining authorities are overall responsible for the issue of the storage permit. UNGS operations are covered, under:

- Mining law – Bundesberggesetz, which covers gas storage.
- Water framework law (Wasserhaushaltsgesetz), which prohibits the injection of any harmful matter into the groundwater.

Following correspondence with UNGS experts in Germany, the following have been determined.

- Observation wells are not required by legislation. Requirement for observation wells will be determined during the storage permit application, depending on geology, formation pressure, etc.
- It was unclear whether SSSVs are required by legislation, however, all storage wells in Lower Saxony are equipped with SSSVs.
- EN 1918 (a DIN standard in Germany) is being used.
- Production and storage is subject to acquisition of land. In certain cases compulsory purchase is possible.
- For storage facilities environmental impact studies are not generally required unless certain preconditions exist.

France

Exploration and certain operation activities are subject to environmental impact assessment studies. Under Seveso II regulations, safety studies (based on detailed analysis of risks) and preparation of emergency plans are required. Provisions are also included with regards to building construction within a zone at a certain distance from the central station and wells. Also, local residents have to be informed of the potential risks by the operator and compensation is provided in case of damage to property. Underground storage is not subject to acquisition of land and it is possible to acquire by compulsory purchase. Observation wells are required.

Italy

Underground storage operations are not subject to acquisition of land and it is possible to acquire by compulsory purchase. The exploration and certain operation activities are subject to environmental impact studies.

3.2.4 UNGS legislation and CO_2 storage applicability

No UNGS specific legislation could be identified which could be applied directly to geological CO_2 storage. Some countries have extensive UNGS specific legislation and some rely on standards such as the EN 1918, to regulate operation of UNGS facilities.

Legislation studied from the USA, Canada and northern Europe indicates that the existing UNGS regulatory framework, with some modifications, could be used to regulate GCS projects. However, for all countries studied the following generic aspects need to be addressed and clarified:

- Generally, natural gas legislation assumes that natural gas stored underground is an expensive commodity, which must be preserved from escaping the formation. So far CO_2 is portrayed as 'waste', with the potential for polluting underground fresh water.

Therefore, clarification is required on whether CO_2 can be treated as a valuable commodity or a 'waste'.

- Natural gas legislation addresses liability for environmental incidents and damage to property mainly during the operation of an UNGS facility. In general, the UNGS owner is fully liable, if an incident was proven to be a direct result of an UNGS activity and some countries have clear legislation which assigns liability to the owner in perpetuity. However, it is evident that, after wells and site have been abandoned, the government, eventually, assumes liability for the site, as companies have either ceased operation or merged with other companies. Therefore, ownership of the post-abandonment injection wells and CO_2 injected, should be clearly defined.
- Mainly offshore, there is a clear requirement for post-abandonment monitoring of remaining facilities. However, GCS long term monitoring requirements should be clarified, as they can extend into thousand of years.
- Duration of ownership of the post-abandonment GCS project and consequent monitoring requirements should be addressed. Reducing these requirements from perpetuity to a fixed period of time (eg, 50-100 years) would encourage GCS projects and minimise future uncertainty. Some form of insurance or bond would be required, for eg, post-abandonment well repair.
- To assist international emissions trading (eg, tax credit, etc) schemes, legislation should also cover inventory verification.

The CO_2 relevance of UNGS legislation for each country studied is discussed below.

USA – UNGS legislation and CO_2 relevance

Generally, legislation in the USA is state specific with some states having UNGS specific legislation, whereas others use generic oil and gas legislation (including standards) to cover UNGS activities. However, as a minimum, UNGS injection operations are covered under federal injection well regulations, the UIC Program.

The legal management of GCS can not be directly linked to the legal framework of existing natural gas storage legislation and the main issue to be resolved is whether CO_2 is classified as 'waste', under the Clean Water Act and Safe Drinking Water Act (1974). Also, the term 'substance' needs clarification, in order to determine whether CO_2 would fall under the inclusions or exclusions.

CO_2 storage under the existing US regulatory structure would be regulated under the UIC program. Deep injection of hazardous or non-hazardous industrial wastes is categorised as Class I. Class II includes wells associated with energy production (eg, EOR).

Existing small scale, experimental CO_2 injection, associated with EOR, was permitted under the Class V regime (not Class I)[12]. EOR projects using CO_2 could be regulated under Class II rules and through the agency responsible for Class II regulations.

CO_2 injection in saline aquifers is more likely to be regulated under Class I rules. Another possibility is for the federal regulators to introduce a new category, specifically for GCS. However, it is more likely that CO_2 will be classified as waste and CO_2 injection will be classified as Class I. Another possibility is CO_2, especially when used for EOR, to be given a

Class II designation, as CO_2 injection is a standard practice and the cost of a more stringent permit (Class I) would discourage CO_2 storage.

As the vast majority of the future GCS sites in the USA are likely to be onshore, the main GCS concern would be injection under USDW. As CO_2 needs to remain in a supercritical state, if the formation is under a USDW, it will probably be injected beyond the deepest underground source of drinking water. Potentially, the integrity of the water quality could be compromised to some degree and injection may have to comply with the 'non-migration' standard. Both, Class I and II forbid migration of injectate or formation water into USDW and similarly to municipal waste-water injection in Florida, projects might be vulnerable to lawsuits, if they violate the non-migration standard.

During UNGS operation, the operator is responsible for any leakage remediation. Typically, when a natural gas storage site is shut down, as much of the gas as practically possible is removed. The injection wells are then plugged and abandoned according to relevant regulations and procedures. Most of the monitoring requirements focus on ensuring that wells are not leaking during operation and no long-term monitoring is required after the project has been shut down.

Specifically for Class I wells, the owner of the hazardous waste well must prepare a plan for post-closure which includes:

- pre-injection pressure,
- closure pressure,
- time predicted until the pressure decays to the point that the well's cone of influence no longer intersects the base of the lower USDW. The owner must continue groundwater monitoring until pressure has decayed sufficiently, as to not affect the lower USDW. Also, the owner must demonstrate financial responsibility for the post-closure care.

Prior to the development of an UNGS facility, a bond (eg, a cash fund) is required, until all wells and site have been properly abandoned. Some states operate an 'orphan well fund' in case of an emergency, such as plugging an old leaking well, which its last owner cannot be traced. Long term residual liability could be difficult to define, as company structures change over the years eg, through mergers; and the states eventually will resume long term liability.

Legislation such as the U.S. Natural Gas Pipeline Safety Act allows federal government to regulate interstate transportation and storage of gas. Legal cases are handled by each state via 'common law' and courts do not consider operation and storage of natural gas to be an abnormally dangerous activity. This means that the potential risks associated with the natural gas are significantly less than associated public benefits. Therefore, it is only negligence, ie, the failure of exercising reasonable care towards others, which can be associated with natural gas projects. If CO_2 is accepted as a 'non-abnormally dangerous activity' then liability can be treated similarly to natural gas liability. This liability analogue can be easily enforced during the injection years.

Assuming that CO_2 is treated as waste, then, after CO_2 injection has ceased and wells have been abandoned, liability will be difficult to assign, not only in the long term (eg, after 1,000 years) but also in the short term. Communication with state officials indicated that it is very difficult, even after eg, 50 years, to hold the last owner of a leaking well responsible, as the company could have gone out of business or merged with another company.

Canada - UNGS legislation and CO_2 relevance

In Canada CO_2 storage will be influenced by federal, provincial and international legal frameworks. Existing regulations (including EOR, acid gas and oil field waste disposal) and standards (Z341-98), address most of the injection and storage issues, but they do not deal with the long term storage, monitoring and liability issues.

The following regulatory framework gaps have been identified[133]:

- Following some modifications, the existing regulatory framework (including EOR, acid, gas and oil field waste disposal and abandonment regulations) can address most issues related to capture and GCS projects, at least in the early stages.
- Gaps become more evident as projects move into pre-abandonment and abandonment phases.
- Current Canadian frameworks do not deal directly with long term monitoring and liability issues.
- Existing Canadian frameworks could be used, however CO_2 should be clearly defined (eg, waste or not) and valued.

UK - UNGS legislation and CO_2 relevance

Regulation of UNGS sites in the UK cannot be directly applicable to GCS projects. The major clarification that is required is whether CO_2 is considered a waste or not.

Assuming that CO_2 is considered a waste product, then storage operations will be regulated by the EU's Waste Framework Directive and Landfill Directive, which are implemented in the UK through the Pollution Prevention and Control (PPC) Regulations (even though they have not been drafted for CO_2). Also, consideration would have to be given to the Best Environmental Option and Best Available Technique.

A storage site permit under PPC, will not be required if CO_2 is not considered a waste product.

The Water Resources Act and Groundwater Regulations could affect CO_2 storage and even EOR if there is a large CO_2 leakage in 'controlled water' (includes groundwater and aquifers). The Water Framework Directive required member states to prevent 'direct discharges of pollutants into groundwater'.

Netherlands - UNGS legislation and CO_2 relevance

The Environmental Management Act (including Act of 21 June 2001) stipulates that CO_2 can be classified as a waste in the context of underground storage. However, the relevant Dutch regulations (Dutch: BAGA, RAGA and RAAGA), which have been replaced by the European wastes list (Dutch Eural) do not specifically state that CO_2 is a hazardous waste.

Germany - UNGS legislation and CO_2 relevance

Legal situation with regards to CO_2 storage is unclear in Germany. The Mining law addresses underground storage of natural gas. The waste and recycling law (Kreislaufwirtschaft und Abfallgesetz) applies only to gas containers and their emissions. The water law (Wasserhaushaltsgesetz) prohibits the injection of harmful substances into groundwater irrespective of groundwater salinity or depth.

France - UNGS legislation and CO_2 relevance

The existing regulatory framework cannot be used directly and certain modifications will be required. The main clarification is, whether CO_2 is considered a waste or a valuable commodity.

International treaties and CO_2 relevance

There are three main international institutions that could play a role in geological CO_2 storage:

- The Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (the London Convention – LC) and the 1996 Protocol to the Convention.
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR convention).

The LC and the 1996 protocol prohibit the dumping at sea of industrial waste. Regulation of dumping is also governed in the North Sea under the OSPAR convention. Therefore, if CO_2 is considered a waste product, storage in underground formations would be prohibited. Another point is that the relevant committees addressed CO_2 ocean storage, rather than underground CO_2 storage.

The LC and Protocol contain a number of exclusions that could be used for regulating GCS. These are:

- <u>Storage of CO_2 derived from an offshore platform.</u> GCS could be excluded from what constitutes 'dumping of waste', as CO_2 would be stored to prevent it from entering the atmosphere, rather than being an emission from the normal operation of the platform. During the seventeenth consultative meeting of the London Convention it was discussed that 're-injection' of water and other matter associated with offshore oil and gas operations, does not fall within the Conventions definition of 'dumping'. Therefore, CO_2 operations involving EOR may be permissible under the Convention.
- <u>Placement in the maritime area.</u> The LC and protocol exclude from the definition of 'dumping' the 'placement of matter for a purpose other than the mere disposal'. Therefore, it could be argued that carbon injection is a temporary measure, until the climate deterioration comes under control. However, the term 'placement' has not yet been clarified by the contracting parties of the London Convention.
- <u>Pollution in emergencies.</u> Dumping is allowed during an emergency, due to eg, 'stress of weather', when the safety of human life or vessel is threatened (force majeure). Arguably, 'stress of weather' could include climate change and GCS could reduce, by minimising greenhouse gases, the likelihood of damage to human life.

Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter (OSPAR).

This is the 1972 London Convention, which has been ratified into law in countries which are members of the OSPAR convention. The latest, 1996 London protocol, which could become law in the future, is the only one relevant to CO_2 storage offshore. However, the list of banned or allowed materials does not include CO_2. Under the London Convention it is not clear whether CO_2 is an industrial waste and hence its disposal into the oceans (including the sub-seabed – 1996 Protocol addition) would violate the convention.

Generic CO_2 regulatory framework

It is evident from the reviewed UNGS legislation, that a societal decision was taken at the early stages of gas storage, that the benefits of gas storage outweigh any negative impacts. Similarly, a decision should be taken on whether CO_2 emissions could change irreversibly the climate of the earth and whether the benefits gained from CO_2 storage will outweigh the risks associated with GCS. In preparing the CO_2 regulatory framework cooperation will be required between regulatory agencies, government officials and international agencies. Also common ground and cooperation at a global level will be required for schemes such as carbon tax credits.

Existing UNGS legislation was found to be mostly procedural (eg, maximum injection pressure should not exceed 90% of the fracture pressure), with some performance measures (eg, no migration of fluids is allowed). A similar approach can be used for CO_2 storage; however consideration should be given to toleration of 'small and acceptable' CO_2 leaks over a defined time frame (as is the case for radioactive nuclear waste). The difficulty will be to set the criteria for what a 'small and acceptable' leak is. Nevertheless, risk criteria for CO_2 storage will have to be defined, similarly to the oil and gas and nuclear industries. The criteria, more generally, should consider risks on both a local and global level.

- Local level: risk to people or animals, contamination of drinking water, damage to hydrocarbon and mineral resources, CO_2 effect on flora, induced seismicity and ground heave.
- Global level: risk from CO_2 release to the atmosphere.

Risk criteria would be difficult to define for the long timescale required for CO_2 storage. As criteria and indeed legislation can change in a matter of years, is unrealistic to expect that existing legislation will be in place in the coming millennia. However, experience from radioactive waste disposal legislation and risk criteria, can be used as an analogue for long term CO_2 storage.

Another important question is for how long injected CO_2 will present a risk to people and the environment. As this question is crucial for permitting purposes, it is unclear whether CO_2 specific legislation can be integrated within existing legislation or whether a new regulatory framework needs to be defined.

The most important aspects of the CO_2 regulatory framework, which form the basis of the permitting process are discussed below.

Site selection

Site selection includes both the identification of an appropriate geological formation to be used for storage and also the location of the surface facilities. Regulatory requirements for the development and operation of aquifers and hydrocarbon reservoirs can influence site selection. In European natural gas storage legislation, there is greater demand for detailed analysis for aquifers than for hydrocarbon reservoirs. This is based on the proven containment of the depleted reservoirs and the assumption that more data required for the hydrocarbon reservoirs are available compared to aquifers.

A probabilistic site assessment could be performed to evaluate the acceptable leak levels, in accordance with the specific risk criteria. Small CO_2 leaks could be tolerated over a defined time frame, as is the case for radioactive nuclear waste. This approach will incorporate some elements of imperfect storage into legislation and hence could provide flexibility in the legislation.

Also public acceptance will be a significant issue during site selection, especially if the compulsory purchase of land option is exercised. As with the case of existing underground gas storage facilities, local objection should be anticipated. Therefore, keeping the public informed on the need for CO_2 storage as a viable step for greenhouse gas mitigation, is very important.

Maximum allowable surface injection pressure

CO_2 legislation should ensure, in line with existing UNGS legislation, that the maximum allowable surface injection pressure is less than the fracture pressure. This will prevent, or at least minimise the potential of fractures through the overlying strata that could cause leakage from the reservoir and potentially enable stored CO_2 to enter a fresh water strata.

Existing UNGS legislation varies, with some licensing agents specifying different maximum injection pressure, eg, in Canada is 90% of the fracture pressure and in Kansas is 75% of the fracture gradient, with the option for increasing pressure upon application. Other licensing agents do not state a specific limit, such as in Florida where an upper limit of allowable injection pressure should be specified and accepted by the state's agency.

EN 1918-1998 standard gives more specific guidance on maximum operating pressure for aquifers, than for oil and gas reservoirs. However, in order to exceed the initial reservoir pressure detailed investigation is required by the standard. The approach taken in EN 1918-1998 standard maybe more appropriate for CO_2 storage, which gives the flexibility to adjust the maximum allowable injection pressure to a suitable for the location pressure, without being prescriptive.

Well design and testing

Legislation for well design should require as a minimum, compliance with the relevant national or international standards. As the injection duration is insignificant compared with the thousands of years required for CO_2 'permanent' storage, importance should be placed on legislation for appropriate selection of materials.

SSSV could be required, especially for depleted reservoirs, where gas can escape, reservoirs with H_2S and sites near dwellings and public areas.

Well abandonment

Similarly to the oil and gas industry, well abandonment could follow relevant legislation and guidance. Plugging requirements are similar for most of the countries and states studied. However, a notable difference is the depth of the cement plugs, ranging from 50ft to 200ft above or below a drinking water stratum. The UKOOA Guidelines[8] for the suspension and abandonment of wells, provide a general guidance for an 100ft isolation plug above and below of any transition zone, whereas Florida legislation requires 200ft cement plugs. CO_2 related legislation could consider even deeper cement plugs as the reservoir will be plugged pressurised, compared to depleted, low pressure, oil and gas reservoirs. Therefore, careful selection of barrier (cement) and placement technique will be required.

Monitoring (see also Section 3.5.4)

The majority of the legislation studied regulates monitoring during the operational phase of a gas storage facility; and the main requirements are:

- Wellhead and well logs (eg, pressure, temperature and noise log).
- Surface gas detectors, monitoring lower explosive limit (LEL) and H_2S concentrations, where applicable.
- Induced seismicity and heaving monitoring.
- Observation wells, especially for converted aquifers and depleted reservoirs (if required).

Legislation studied, generally does not cover monitoring provisions for wellbore post-injection abandonment for onshore sites. For offshore installations[148], following installation abandonment, any remains (eg, abandoned subsea pipelines) should be monitored at suitable intervals and provision should be made for maintenance or remedial action if required. No specific mention is made on seismic observation requirements.

In more detail, legislation on GCS monitoring should cover the following.

Wellhead and well logs

Similar to UNGS wellhead monitoring (eg, pressure, temperature and noise log).

Surface monitoring

Surface CO_2 monitoring (CO_2 in air, water and soil) should be required. Monitoring over natural background CO_2 flux has not been demonstrated for large-scale operations and hence legislative requirements can concentrate on large CO_2 level monitoring.

Surface monitoring should also include provision for induced seismicity and heaving, especially for onshore sites.

Subsurface monitoring

Subsurface monitoring is very important, especially during the injection years and until the CO_2 bubble has stabilised. CO_2 subsurface monitoring should be required to ensure that CO_2 has not leaked out of the intended formation.

Experience from UNGS legislation indicates that, observation wells are mainly required for aquifers rather than for depleted reservoirs. Canadian legislation based on Z341-98 standard requires observation wells for aquifers as well as depleted reservoirs. Also, EN 1918 states that observation wells should be implemented for depleted reservoirs, if required. It should be noted that in UNGS facilities, monitoring is required mainly to ensure that injected and withdrawn gas are in balance, within operating limits; and also that there is no loss of containment. For GCS projects, monitoring is required to ensure that there is no CO_2 leakage from the reservoir. Therefore, CO_2 legislation could include provision for observation wells, during the CO_2 injection period, mainly for aquifers with an option for depleted reservoirs.

Seismic monitoring is not mentioned in UNGS legislation, however, consideration could be given to seismic techniques (eg, 3D seismic) when considering subsurface post-injection monitoring, especially near urban areas (see Section 3.5.4).

Duration of monitoring
Duration of monitoring is a very important aspect of a GCS legislative framework. Surface monitoring can be treated similarly to the abandonment of offshore installations and monitoring at suitable intervals, should be required.

Subsurface monitoring over thousand of years can be very expensive and may discourage GCS projects. Observation wells will be expensive to maintain and over the years they could potentially provide pathways for vertical CO_2 migration to surface.

It is evident, especially from the nuclear industry, that legislation can change significantly in a matter of years due to better understanding of the subject and improved technologies.

Therefore, monitoring can be split into (see also Section 3.5.1):

- Short term monitoring, where the reservoir containment is monitored, with eg, observation wells, over a fixed period of time, eg 50-100 years.
- Long term monitoring. Assuming that the initial monitoring period has confirmed reservoir containment and CO_2 bubble stability, consideration can be given to abandonment of the monitoring wells and using alternative monitoring methods (eg, geophones and ROV for offshore GCS projects) to monitor reservoir containment.

Local and global monitoring
Monitoring requirements need to be set on a local and also global scale (see Section 3.5). Local monitoring requirements have been described above. Global scale monitoring will provide assurance that international and national CO_2 emission reduction goals are being met.

<u>Operational and residual liability</u>
Liability associated with CO_2 storage can be divided into:

- Operational liability. The operator is responsible for incidents affecting health, safety or the environment during the CO_2 injection phase.
- Post-injection (location specific) residual liability. Liability associated with CO_2 leakage from the geological formation, after injection has ceased and wells and site have been properly abandoned.
- Global liability. Liability associated with the deviation from the goal of permanent CO_2 storage.

Operational liability
Operational liability can be covered under existing legislation (eg, EOR and UNGS legislation) which can be considered adequate for the CO_2 injection phase.

Post-injection liability - ownership
Post-injection residual liability starts after injection and continues into millennia. Legislation studied varies with regards to residual liability. Where residual liability is defined, it could be allocated in perpetuity to the subsurface licensees (mineral owners).

However, this is difficult to enforce in the long term. Communication with USA state officials indicated that similar scenarios have occurred, where the state had to replug ten leaking abandoned wells. As it was impossible to trace the owners or operators, which had either merged or gone out of business, the state had to use a trust fund to pay for the replug. The state officials specifically raised their concern that the current fund assets are not sufficient, especially for deep wells, which are very expensive to replug. Also they stated that 'if the state needed to pay for several plugging/abandonments at one time, the trust fund itself would go bankrupt'.

It is impossible to guarantee the viability of a company over a long period of time and also, if liability costs are significant, then decisions on GCS projects may be influenced. Separating short term residual liability from long term residual liability could act as an incentive for an operating company and will be easier to insure against future leakage.

It is more likely that eventually the government will bear any residual liability, rather than the operating company. Therefore, it is proposed that residual liability is split into short term (eg, 50-100 years) and long term (eg, 100+ years). Short term residual liability can be imposed on the operating company, followed by transfer of liability to the government, after a fixed period of time.

Additionally, bonds (eg, cash funds) are required, in the oil and gas industry, until all wells and site have been properly abandoned. Also, in some countries a contingency fund is in place in case of an emergency. For example, in some states of the USA an 'orphan well fund' is in place for plugging old leaking wells. Similarly, the government could charge emitters a levy to create a fund for the long term monitoring and, if required, remediation of a CO_2 storage site.

Consideration should also be given in the way that legal issues and liabilities are addressed for Radon and whether these can be directly applicable to GCS.

Global liability

Global liability should be treated at an international level as any CO_2 leakage will be more important under future carbon regimes, such as carbon tax credits.

Subsurface rights

It is important to clarify who owns the underground pore space, where CO_2 is stored. In the UK and Canada the mineral owner owns the subsurface space, even after the minerals have been removed[12]. A large number of cases in the USA have upheld that after the removal of underground minerals (eg, oil and gas) the surface owner retains the right to use the remaining space for storage. As CO_2 is not a valuable commodity a clarification may be required that CO_2 remains the property of the injecting company. CO_2 injection from multiple operators into the same reservoirs should also be addressed.

General GCS issues

The CO_2 regulatory framework should also consider the following.

- An emergency/contingency plan, a safety study and a quantified risk assessment should be required.
- Legislation should clearly define the need for an environmental study for GCS projects. An EIA can be very time consuming as government agents, members of the public and interested groups should be allowed appropriate opportunity to comment on the EIA.
- CO_2 verification. There is a great uncertainty on accounting for Verified Emissions Reductions (VER), due to inability to verify that there will be no leakage until most of the CO_2 has been permanently fixed into the reservoir. As this timescale can run into millennia, regulating CO_2 verification will be very difficult. Setting short term legislation (eg, for 50-100 years) will minimise uncertainty and encourage GCS projects.
- Existence of a CO_2 project near a natural gas storage formation. Legislation in the USA allows drilling and production through an existing UNGS reservoir, assuming adequate safeguards are in place to prevent fluid migration or contamination. Similarly, as the example of Sleipner has demonstrated, CO_2 storage can take place near a production formation and legislation should address the need for no or minimum cross contamination.
- UNGS legislation studied indicated that operators are required to keep a log of each well and also details of all abandoned wells (including wildcat wells). This has not been very successful, especially in the early years of the oil and gas industry and many unregistered leaking wells are discovered and plugged every year. Therefore, for GCS projects, logs should be kept for each well by the operator and records of all active and abandoned wells should be kept by both the operator and relevant government agent.

3.3 UNGS leakage incident analysis and CO_2 relevance

The following steps were taken in order to analyse UNGS leakage incidents and derive a CO_2 leakage frequency from an underground GCS reservoir.

- Identify reported UNGS leakage incidents.
- Assess leakage incidents causes, consequences and remedial action taken.
- Derive a UNGS leakage frequency.
- Assess applicability of derived UNGS leakage frequency to GCS.

3.3.1 UNGS leakage incidents, consequences and remediation action taken

Information on UNGS leakage incidents (see Table 3.11) was obtained from the following sources:

- 'Natural gas storage experience and CO_2 storage[6]'. This report identifies reported incidents of leaks in gas storage reservoirs and it is based on a literature search and interviews with UNGS operators. The companies interviewed included operators of UNGS facilities (depleted reservoirs, aquifers and salt caverns) from Germany, Netherlands, UK, Norway, Denmark, France, Belgium, Italy, Spain, Poland, Austria, Portugal, Russia, Slovakia, USA and Canada.
- 'Lessons learned from natural and industrial analogues for storage of carbon dioxide in deep geological formations[13]'.
- Discussions with UNGS operators, consultants and literature/internet search for articles on reported UNGS leakage incidents (Section 5).

UNGS leakage incidents identified are listed in Table 3.11, at the end of this section. It is believed that available information on UNGS leakage incidents does not include all leak incidents that occurred in every UNGS facility, especially prior to the 1970s. However, it is believed to have captured at least all significant leakage incidents and is as complete as a literature search allows. Based on the available information, the following conclusions can be made:

- There were approximately nine reported UNGS leakage incidents prior to the 1970s.
- Between the 1980s and 2004 eight UNGS leakage incidents were reported.
- From the 1980s to date, there was one UNGS leakage incident in a depleted reservoir and one in a converted aquifer, both with minor consequences (no reported injuries). During the same period, there were six leakage incidents in salt caverns and converted coal mines; two of which involved fatalities. Catastrophic leaks, where a large volume of gas leaks to surface, can mainly be associated with caverns, as once a leak path is developed there will be a rapid move of gas along the leak path. A small leak in a cavern could result in a concentrated gas release to surface, whereas a small leak from a porous reservoir is more likely to result in a diffused gas leak. Therefore, the impact of a leak from a cavern is more likely to be severe, compare to a diffused gas leak from a porous reservoir.

- The majority of the leaks were associated with wellbore failure or loss of well control and also two incidents were the results of caprock leakage. Remediation action taken was mainly, to repair the wellbore, recycle gas from shallow zones, remove water to minimise reservoir pressure or even abandon the reservoir.
- The main consequences from the reported UNGS gas leaks were gas explosion and fire. However, ground heaving, subsidence and stimulation of earthquakes in certain areas, have also been associated with operation of UNGS sites.

3.3.2 UNGS leakage frequency calculation

Estimating an UNGS leakage frequency is quite challenging, as there is a shortage of information on UNGS leakage incidents. However, it is believed that the UNGS leakage incidents identified in Table 3.11 should at least cover a large proportion of the significant UNGS gas leaks. The term 'significant' is used in this report for incidents that resulted in injury/fatality, property damage, site evacuation or uncontrolled leak. Leaks caused by eg, casing failure, which could easily be remedied, are considered unlikely to be included in Table 3.11.

The approach used in this report to calculate a UNGS leakage frequency, is as follows:

- Calculate UNGS leakage frequency using documented UNGS leakage incidents. Also calculate from IGU database[1] the cumulative UNGS site and well-operating years.
- Identify relevant blowout frequency from oil and gas production reservoirs. Blowouts are the nearest events to a substantial uncontrolled release from a reservoir and are well documented by the offshore industry.
- Compare and assess leakage frequencies obtained from the above methods and also from the Marcogaz study[49].

UNGS leakage frequency calculation based on leakage incidents from UNGS facilities

Seventeen accidents, associated with gas leakages from UNGS facilities (aquifers, oil and gas reservoirs, salt caverns and converted coal mines) were identified (Table 3.11).

The IGU database[1] includes detailed information from UNGS facilities around the world and was used to calculate the cumulative years of UNGS site and well operations. The cumulative years of UNGS site and well operations were calculated as 20,271 UNGS-years and 791,547 well-years, respectively.

Due to the limited number of leakage incidents identified, incidents from depleted reservoirs and aquifers, as well as leakage incidents from salt and coal mines were used, in order to estimate the UNGS leakage frequency.

From the seventeen UNGS leakage incidents identified, one occurred during maintenance of surface equipment and was not included in the UNGS leakage frequency calculation; and the remaining sixteen were associated with underground causes (eg, well leakage, etc). Two of the leakage incidents resulted in fatalities. The UNGS leakage and fatality frequencies associated with UNGS facilities, have been calculated as follows:

Table 3.10: Significant gas leak and fatality frequencies

Significant gas leak frequency *	Fatality frequency from a gas leak *
$8.39x10^{-4}$ /site-yr	$9.87x10^{-5}$/site-yr
$2.02x10^{-5}$ /well-yr	$2.53x10^{-6}$/well-yr

* Surface gas leakages are not included

Therefore, the frequency of a significant gas leak from an UNGS facility was calculated as $8.39x10^{-4}$ /site-yr, or once every 1,192 years of site operation. The frequency of a significant gas leak from an UNGS well calculated as $2.02x10^{-5}$ /well-yr, or once every 49,505 years of well operation.

The fatality frequency from a significant gas leak from an UNGS facility was calculated as $9.87x10^{-5}$ /site-yr, or once every 10,132 years. The fatality frequency from a significant gas leak from an UNGS well was calculated as $2.53x10^{-6}$ /well-yr, or once every 395,257 years.

Marcogaz study

Marcogaz conducted a similar study[49] where seven UNGS operating companies in the EU were interviewed, in order to identify leakage incidents and derive a UNGS leakage frequency. The Marcogaz report concluded the following.

- The main hazards leading to accidents on UNGS facilities are related to surface process leakages.
- Accident frequency in the seventies was about the same as in the eighties. However, accident frequency was half as high in the nineties. This is perceived to be due to increased experience.
- Accident frequency, resulted from well leakage was calculated as $5.1x10^{-5}$ accidents/well-yr. Severe injury frequency was calculated as $1x10^{-5}$ accidents/well-yr (there were no fatalities reported).

UNGS leakage frequency based on oil and gas well blowout data

Another source of comparable experience is from blowouts (uncontrolled gas releases) from oil and gas reservoirs, which are well documented[14, 15]. The three types of blowouts associated with production operations are production, workover and wireline blowouts. Production blowout frequency estimates, can be considered more appropriate to approximate a significant uncontrolled leakage from an UNGS well, compared to a wireline or workover blowout. Holland[14] suggests a production blowout frequency of $5x10^{-5}$ per well-yr or a significant gas release from a well once every 20,000 well-years.

UNGS leakage frequency assessment

The UNGS leakage frequency, from subsurface causes, was calculated as $2.02x10^{-5}$/well-yr, based on leakage incidents identified in Table 3.11 and UNGS site and well information from the IGU database. This frequency was also compared with the leakage frequency identified in the Marcogaz study and blowout frequency from the oil and gas industry.

The UNGS leakage frequency estimated in the Marcogaz study is given as 5.1×10^{-5}/well-yr and has been obtained following a survey of UNGS operators in the EU. The Marcogaz frequency was also found to be very similar to the estimated oil and gas blowout frequency.

The leak frequency calculated in the Marcogaz study is approximately 2.5 times higher than the leak frequency calculated in this report. A possible explanation is that leakage incidents identified by Marcogaz during the EU operators' survey, could possibly include significant gas lekages (ie, incidents that resulted in damage, injury, or significant gas release, etc) as well as minor gas leakages (eg, injection tubing leakage).

In comparison, the UNGS leakage incidents identified in this report could include mainly significant UNGS leakage incidents; as reporting of minor incidents, especially prior the 1970s cannot be considered reliable. Therefore, it is suggested that:

- The Marcogaz leakage frequency (ie, 5.1×10^{-5}/well-yr) could provide a better approximation of a representative UNGS gas leakage frequency in Europe.
- The UNGS leakage frequency calculated in this report (ie, 2.02×10^{-5}/well-yr) could be used to describe a less frequent, but significant UNGS gas release, with significant consequences.

3.3.3 Leakage analysis for GCS

Similarly to UNGS gas leakage, wellbore leaks could be the most significant leakage source during geological CO_2 storage, followed by caprock leaks. Figure 3.4 illustrates the potential leakage pathways and consequences of CO_2 leakage[20]. The following sections discuss the main CO_2 leak causes, their consequences and estimated CO_2 leak frequency.

Wellbore leaks

Wells are the most likely places for leakages to occur, either through the borehole or through the annulus outside of the borehole (see Figure 3.4). These leakages could be associated with:

- Improper well design, construction, operation or maintenance.
- Corrosion, as CO_2 is highly corrosive, especially when existing facilities, which are not designed for CO_2, are used for CO_2 injection. Potential also exists for CO_2 corrosion induced fracture of the casing or tubing.
- Inadequate cementing of casings, which could allow stored CO_2 to escape from the storage formation, to overlaying formations.
- Abandoned oil and gas wells, undocumented wells and dry holes, old dry holes, water wells and brine wells. This can be more important, in areas of high drilling activity, especially prior to 1970s. For example in the USA, millions of wells have been drilled, many of which were inadequately constructed, improperly plugged and may not be documented. These wells are likely to have collapsed boreholes and they can provide a leakage path to surface. Research from an independent consultant[16], indicated that, 10% of all plugged and abandoned wells in California, leaked in one year.
- Cemented casings and cement plugs, which have to withstand in excess of 1,000 years. Conventional cementing technology (eg, portland cement) cannot guarantee the thousands of years required for successful CO_2 storage.

- Higher pressures in the GCS reservoirs, than in depleted reservoirs or converted aquifers.
- Shallow groundwater wells. CO_2 leakage into groundwater is likely to be dissolved into the water, affecting its quality.
- Subsurface formation movement. Reservoir compaction or overburden formation faulting and bedding plane slip could result in well casing damage. Compression and buckling damage is most often found within compaction zones, near perforations.

Caprock leaks

Caprock leak or horizontal migration through faults and fractures (see Figure 3.4), can occur when:

- Geology of the site has not been properly characterised.
- Pressure of the reservoir is too high, allowing the stored gas to migrate horizontally or fracturing the caprock, resulting in vertical migration.
- Permeability of the caprock is not sufficiently low and the CO_2-water capillary pressure exceeds its entry pressure (or threshold pressure). If the capillary entry pressure is reached, CO_2 can cross the caprock seal and leak into overlaying formations. CO_2 can also react with certain minerals bound in the caprock and either increase or decrease sealing capacity.

CO_2 leakage (see Figure 3.4) through faults and fractures can:

- Reach the surface as CO_2 gas or as CO_2 dissolved in groundwater (shallow aquifer). If the leak is contained within the shallow aquifer, assuming the aquifer is not a source of drinking water, then the CO_2 may still be considered successfully trapped. The most likely leakage scenario is CO_2 seepage from small reservoir leaks, in the near-surface environment. The dense CO_2 is anticipated to accumulate and build up in the vadose zone and released to surface through a fault or released directly across the land when no vadose zone exists due to high water table.
- Affect the flowing surface water by reaching the baseflow water, which forms groundwater input into surface water.
- Accumulate at the bottom of a deep lake. Following supersaturation or a triggering event, CO_2 eruption can occur (eg, Lake Nyos CO_2 eruption). For the majority of the lakes, temperature variations prevent build up of supersaturated gases at depth. In the tropics only three lakes have been found with stable conditions and no annual temperature variation. These are, Nyos and Monoun in Cameroon and Kivu in Rwanda and Congo[20].
- Diffuse into or through low permeability formations. However, if CO_2 is trapped in the low permeability formation, then CO_2 is considered successfully trapped.

GCS leakage consequences

The effects of CO_2 leakage to human and environment are discussed below and also analysed in Section 3.6.4.

CO_2 can flow to the surface as gas or as CO_2 dissolved in groundwater (see Figure 3.4), mainly as bicarbonates ($HCO3^-$). However, a small quantity of CO_2 leakage from a wellbore, that has not affected drinking groundwater, is not considered sufficient to affect human or environment and can be considered relatively straightforward to repair, with existing oil and gas techniques. In certain concentrations CO_2 could also benefit the ecosystem, as CO_2 is a plant nutrient and a major component of the atmosphere. However, at higher concentrations it can affect humans and the ecosystem.

The main CO_2 leakage consequences (see Figure 3.4) are analysed in Section 3.6.4 and are summarised below.

- CO_2 gas at high concentrations ie, greater than 30% CO_2 can be lethal. CO_2 releases to surface can accumulate in basements or in topographic depressions and result in asphyxiation.
- Overpressurised CO_2 may push salt and water upwards, potentially raising the water table or move toxic minerals until they become exposed to eg, underground fresh water.
- CO_2 storage may result in ground heaving or even stimulation of earthquakes in certain earthquake prone areas. For example, deep injection of liquid wastes below the Rocky Mountain Arsenal (Colorado) has been blamed for earthquakes, dating back to 1962.
- CO_2 at high concentrations can affect soil, water quality and vegetation.
- Large CO_2 leakage can damage hydrocarbon reservoirs, resulting in expensive separation and disposal costs.

A catastrophic rupture of the reservoir could have similar effects, although extremely unlikely, to:

- The Lake Nyos incident, where a large CO_2 release in 1986, killed more than 1,700 people. Human fatalities and ecosystem damage was experienced in a 15 mile-radius area.
- Mammoth mountain (California) incident. Following a series of small earthquakes, CO_2 release was blamed for tree damage covering an area of 100 acres.

So far, there has been no similar natural gas leakage incident and can be concluded that the probability of a catastrophic reservoir failure is extremely remote.

GCS leakage frequency estimation

The UNGS leakage frequency was calculated as 2.02×10^{-5} /well-yr or 8.39×10^{-4} /site-yr; and is based on, mainly, significant gas leaks. The estimated UNGS leakage frequency could be used to represent a large CO_2 leakage from a GCS reservoir with significant consequences.

The fatality frequency calculated in this report from UNGS leakage incidents, cannot be used to estimate the fatality frequency associated with CO_2 leakages. The reason is that all UNGS related fatalities were caused by either fire or explosion, not suffocation, which would have been the case for a significant CO_2 leak.

Following the discussion in Section 3.3.2, the following GCS leakage frequencies could be used:

- $2.02x10^{-5}$ /well-yr, for a significant CO_2 leakage, resulting in significant loss of CO_2, which could, potentially, affect the environment.
- $5.1x10^{-5}$ /well-yr, for an average CO_2 leakage from a GCS facility.

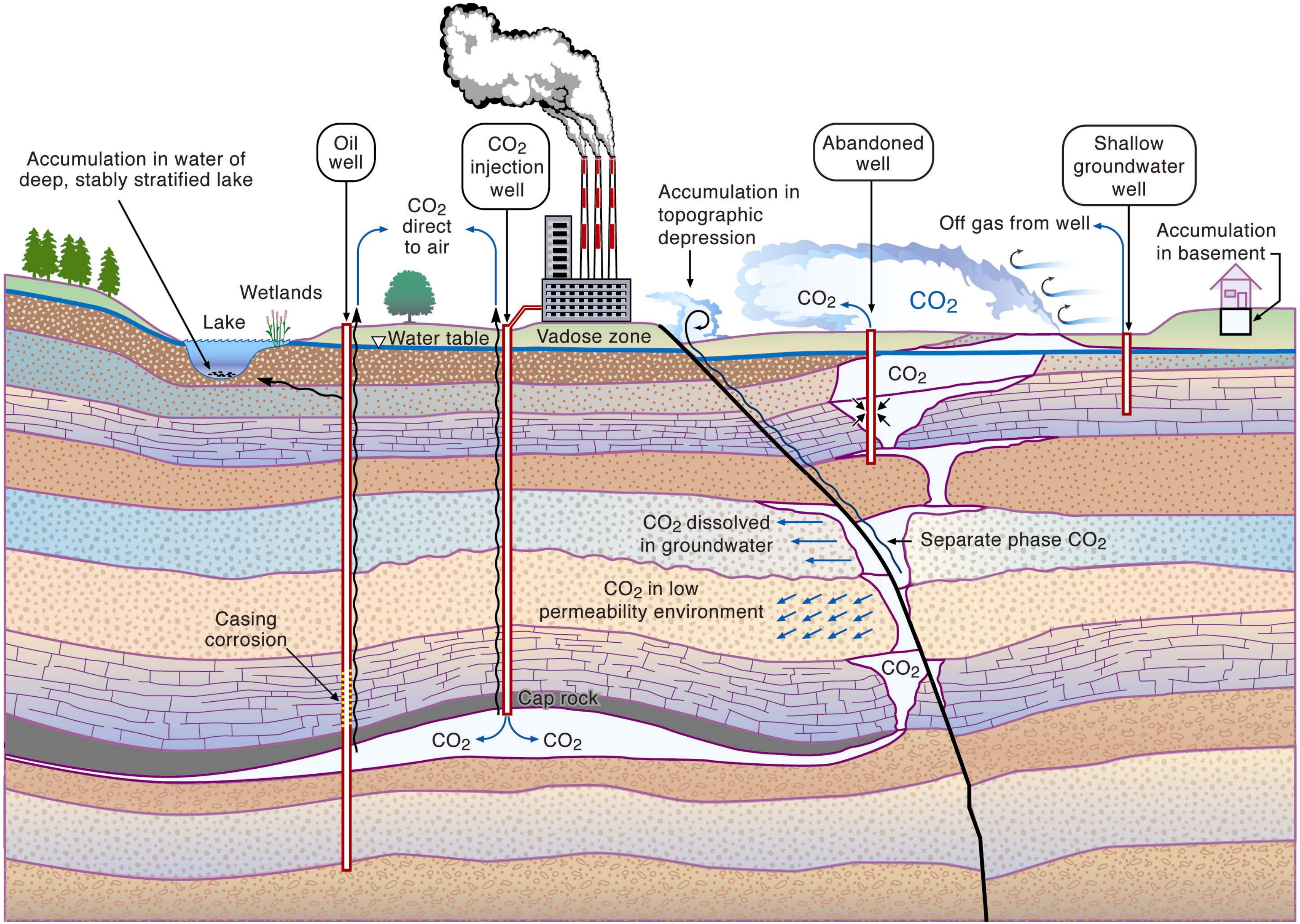
Table 3.11: UNGS leakage incidents identified

No	Reservoir type/location/year	Description/Type of leak	Consequences	Remedial action taken
1	Salt cavern, Moss Bluff, 2004, Duke Energy, Houston Texas, USA.	Well control incident.	Explosion. Evacuation – no injuries.	Not available.
2	Gas reservoir, 2003-4 Magnolia field, Louisiana, USA.	Gas release from cracked well casing.	20 homes evacuated.	
3	Salt cavern field (Yaggy), 2001 Shallow salt zone Kansas - U.S.A.	Wellbore leak. Natural gas from the Yaggy gas storage project apparently leaked from an injection/withdrawal well. The storage structure is composed of several mined salt caverns at least 150 m deep. The leaked gas migrated seven miles to the town of Hutchinson through a 20 foot zone with several dolomite layers interspersed with shale. Within the town, it then flowed up and erupted from old, unplugged wells that no one had known about and that had been used for salt solution mining many decades ago.	Fire/explosion. 2 people killed. Town evacuation.	Wellbore remediation. Vent wells were drilled, but only 20% of the initial relief wells encountered gas.
4	Converted coal mine, 1998 Leyden Colorado, USA.	Defective well, gas reached aquifer.	Leak.	UNGS closed.
5	Seminole pipeline, 1992 Brenham, Texas, USA	Salt storage cavern overfilled and liquefied gas poured into an adjoined brine pit. A low-lying cloud several hundred yards long was created.	Explosion killed 3 people, injured 21 people and caused $9million damage.	Not available.
6	Salt cavern (Lauchstadt 5), 1988 Halle, Germany.	Pipe leak. Ethane leaked upwards into an aquifer and finally broke through to surface. Indication, 1 hr prior to	Buildings displayed	Not available.

No	Reservoir type/location/year	Description/Type of leak	Consequences	Remedial action taken
		eruption of rapid pressure loss of cavern 5.	cracks.	
7	Mont Belvieu, salt cavern, 1980.	Underground gas leak.	Explosion. Authorities ordered evacuation. There were no reported injuries.	Not available.
8	Aquifer storage field. (Leroy), early 1980s. Thaynes Formation, Uinta County, Wyoming - U.S.A.	At this gas storage site, gas was observed bubbling to the surface. Wellbore leak.	Leak.	It was reportedly controlled by limiting maximum injection pressures. Wellbore remediation.
9	McDonald Island, 1974 California, USA.	On 17-May-1974, PG&E lost control of a new injection/ withdrawal well, Whiskey Slough 14 W, which then caught fire. While pulling out of hole, the well fluid level apparently dropped and was not monitored.	Fire.	The fire was extinguished and the well was controlled after 19 days by drilling a relief well and killing the blowout with heavy mud.
10	West Montebello, 1970s California, USA.	In the 1970s, gas was leaking along old, improperly plugged wells to a shallower zone but not to the surface.	Leak.	Problem wells were plugged and the stored gas may eventually be produced.
11	Aquifer storage field. Shallow sand, 1960s/1970s Northern Indiana - U.S.A.	A number of water wells were affected by the intrusion of natural gas. Reservoir selected was too shallow. Such operation would not be allowed under present regulations.	Leak.	Field was abandoned.
12	Aquifer storage field. Mt. Simon Formation Midwestern - U.S.A.	Caprock leak (cause unknown).	Leak.	Gas recycle from shallow zones above aquifer.
13	Aquifer storage field. Mt. Simon Formation Midwestern - U.S.A.	Caprock leak (cause unknown).	Leak.	Field abandoned after small volume of gas stored.

No	Reservoir type/location/year	Description/Type of leak	Consequences	Remedial action taken
14	Depleted gas reservoir Multiple formations West Virginia - U.S.A.	Casing leaks.	Leak.	Rework/recompletion of wells. Casing defect repair.
15	Depleted oil and gas reservoir, Ontario, Canada.	Wellbore leak.	Leak.	Wellbore remediation.
16	Porous rock formation, Spandau, Berlin, Germany.	Explosion at an underground gas storage facility. Incident appears to have occurred while maintenance workers where working on the store's contents gauges, which began to leak.	3 seriously injured. Buildings were damaged by the explosion.	Not available.
17	Herscher-Galesville, 1950. Oil reservoir, IL, USA.	Caprock Leak. In mid-1953, several months after natural gas was first pumped into the Galesville formation, bubbles of gas appeared in shallow water wells in the Herscher field. To this day, the cause of the leakage is still not known with certainty.	Leak.	Wells were drilled around the periphery of the field to remove water and thereby minimize the pressure build-up. The water was then reinjected into the Potosi Dolomite (above the Galesville) in order to pressurize the shallower formation. By carefully monitoring the differential pressures and recycling gas from several vent wells in other still shallower formations, the Herscher-Galesville natural gas storage project has been active for almost 50 years.

Figure 3.4: Illustration of potential leakage pathways and consequence of leakage (Lawrence Berkeley National Laboratory, CO_2 capture project)[20]



3.4 UNGS screening and site selection and GCS applicability

Identification of a suitable underground gas storage facility is a complex decision, taking into account legislation, geological, topographical and physical conditions, safety aspects and also commercial issues, such as capital and operational costs, proximity to population centres and distribution infrastructure.

In general, the criteria used for site selection for natural gas storage in depleted reservoirs and converted aquifers are as follows.

- Formation should be sealed by containment formations and should be strong enough to prevent migration of fluids from the disposal zone. A detailed geological and hydrological study is preferred for the proposed and surrounding area, especially of the containment properties of the formation and potential for geological anomalies that could impair the containment of the storage zone.
- The formation should have sufficient porosity and size to accept the volume of gas anticipated. A good knowledge of market requirements is necessary, as reservoir deliverability is important when selecting an UNGS site.
- Formation depth. Deep wells are generally more expensive and can affect the total capital costs.
- Formation permeability. High reservoir permeability is required for UNGS operations.
- Location of UNGS near existing gas distribution network and if possible, near major cities.
- Existing infrastructure (eg, wells, gas compression stations, etc) from depleted reservoirs, which could be used for gas storage.
- Potential for H_2S presence, heavy metals or natural radioactive substances in the reservoir that could be mobilised during reservoir/aquifer pressurisation.
- Proximity of dwellings, public places and other industrial facilities that could be affected by a gas release.
- Risk from adjacent facilities, regional drainage, eg, creeks, or from abandoned wells, especially unregistered wells and dry water wells.
- Topography of site and proximity to lakes, rivers, marshes and also underground fresh water aquifers. There should be no contamination of a source of drinking water.
- Risk from seismic activity and potential leakage during an earthquake. Risk of seismic events triggered by storage operations are also considered.
- Local weather conditions.
- Proximity to public rights-of-way and access for emergency response.

The performance of an UNGS depends mainly on the formation's geological and geometrical characteristics. The two main types of UNGS facilities considered in this report, are depleted oil and gas reservoirs and converted aquifers; and their main characteristics are described below.

3.4.1 Depleted oil and gas reservoirs

These are the most common UNGS facilities, using oil or gas reservoirs that have been depleted through earlier production. The majority of UNGS facilities worldwide are in shallow depleted oil and gas reservoirs. The reservoir formation consists of a porous and permeable rock, which allows natural gas under pressure to fill in the spaces in the rock. The caprock consists of an impermeable rock that prevents the stored fluid from rising. These reservoirs are naturally occurring and their containment to prevent gas migration has been proven over the millennia, as they were holding the original deposits of oil or gas.

The base gas requirement averages about 50% of the total capacity. Working gas typically ranges from 1 to 40 Bcf. The maximum daily deliverability, ranges from 0.3 % to 33% of working gas capacity, however, the typical range is 1% to 4% of working gas capacity. Generally, depleted reservoirs are designed mainly for seasonal system supply.

Normally, depleted reservoirs are the least expensive and quickest to develop, compared to aquifers, due to available information from the previous development and production operations. Existing wells could be used for injection and withdrawal; and some cushion gas will be available during gas storage. However, this is not always true and comments captured in reference 5 from participating UNGS operators, indicated that there is only a small difference in cost between converted aquifers and depleted UNGS reservoirs. Some possible reasons for this possible cost convergence are:

- some field investigations still have to be undertaken,
- new wells may be required to increase deliverability,
- additional surface injection equipment, which is a major component of total investment costs, may be required,
- new environmental regulations have to be complied with.

Even though depleted reservoirs may seem an ideal candidate for natural gas storage, there are still some disadvantages in converting depleted reservoirs into UNGS facilities.

- Working gas volumes are usually cycled only once per season and mainly they have lower deliverability than non-porous reservoir (eg, salt caverns).
- Often depleted reservoirs are old and require substantial work especially on well maintenance and monitoring to minimise potential for leakage via wellbore leaks into other permeable formations.

3.4.2 Aquifers

Aquifers are geological formations below the seabed or below ground and consist of layers of porous rock filled with water (mainly saline water). The majority of aquifer UNGS facilities are in shallow underground permeable rock formations that act as natural water reservoirs. An impermeable caprock will create a seal preventing vertical movement of fluids out of the reservoir. Aquifers can extend over very large areas and mainly are:

- Closed aquifers (ie, traps in aquifers). These are dome-like formations sealed with an impermeable caprock. Injected gas can accumulate at the ceiling of the dome. As natural gas is less dense than the water in the aquifer, it will remain within the dome, preventing lateral migration.
- Open aquifers (ie, aquifers outside traps). These are regions of aquifers, other than traps and are sealed by impervious layers of caprock.

Aquifer storage is used in limited geographical areas such as in the USA (eg, Illinois, Indiana and Iowa), Russia, France and Germany, mainly due to a lack of depleted oil and gas reservoirs.

For a successful aquifer conversion, the following geological conditions are essential:

- an anticline with sufficient closure,
- an impermeable tight caprock and,
- a porous/permeable reservoir.

Typically, natural gas is injected into the aquifer, so that the gas bubble can be kept in place by the geometry of the structural closure and water pressure. Extensive instrumentation and multiple injection/withdrawal wells are generally used to monitor and control the gas movement.

Advantages of UNGS aquifers include:

- High deliverability rates for a single winter withdrawal period, although aquifer UNGS reservoirs can also be used to meet peak load requirements. An active aquifer water drive can enhance deliverability rates.
- The high deliverability increases the ability to cycle the working gas volumes more than once per season.
- Typically, aquifers are close to end-user markets.

Disadvantages of UNGS aquifers include:

- A high level of geological risk, as they have not been proven to contain hydrocarbons. Therefore, there is a degree of uncertainty on the aquifer ability to contain gas.
- Aquifers are generally more expensive to develop than depleted oil and gas reservoirs, as the geological characteristics are not as well known as for depleted reservoirs. Hence, a significant amount of time and money should be invested to acquire the aquifer geological characteristics and determine its suitability as an UNGS formation.
- Cushion gas requirements are higher for aquifers than for depleted reservoirs, typically between 50-80%. Cushion gas accounts for 30-40% of the development cost of aquifer gas storage facilities.
- A large percentage of base gas is not recoverable after site abandonment. This high base gas requirement could limit the number of new aquifer storage projects, as it increases the initial capital cost. However, some operating companies are using inert gas for

cushion gas. For example, since 1979, Gaz de France has been using inert gas to replace natural gas in three UNGS aquifers.

- Potential for water production exists during the withdrawal cycle, as aquifer reservoirs produce via water drive. These would result in higher operating cost.
- Due to the water drive mechanism during the withdrawal cycle, the base gas requirements are high (50-80%).

Caprock integrity assessment

Caprock integrity is very important for the gas storage industry, especially for the development of aquifers. Oil and gas reservoirs have proven containment, as this is essential for trapping oil and gas. The gas storage industry has developed several techniques for caprock assessment and these are discussed below.

<u>Geological assessment</u>

A good understanding of the geologic formation of the area is essential. The aim is to locate a non-porous, non permeable zone that overlies a porous, permeable zone. Geological assessment is a first, simple step in determining caprock integrity, however, further tests are required. A large, solid anticlinal structure is an important criterion for aquifer storage.

<u>Threshold pressure measurement</u>

Threshold pressure is the pressure that just causes continuous motion of the gas-water interface through the caprock, ie, the ability of the caprock to contain gas. Caprock samples should be used to determine the caprock threshold pressure.

<u>Pump testing</u>

Pump testing involves withdrawing water from the zone under the caprock to lower the pressure and create pressure differential across the caprock. Observation wells are used to monitor the pressure of the upper side of the caprock or pressure within the caprock. Any pressure changes above or within the caprock during pump testing, could indicate a flaw in the caprock.

In addition to determining caprock integrity, the pump test can also be used to:

- measure reservoir properties, by measuring pressure drawdown during pumping and pressure build up at conclusion of the pump test,
- provide permeability information.

It should be noted that changes in the fluid level within observation wells could be subject to external factors such as changes in barometric pressure or industrial activities (eg, waste disposal).

3.4.3 Storage cost

Storage cost consists of capital cost, operating and maintenance cost. Capital cost eg, right-of-way acquisition, exploration expenditures, well drilling, surface facilities (including compression) and pipeline network, is the most expensive cost component of an underground gas storage facility. Operating and maintenance (O&M) costs consist of equipment/well maintenance costs, personnel salaries, insurance and energy (eg, compressor power). O&M costs are significant, but often much smaller than the capital costs. Underground storage cost is mainly a function of:

- Reservoir depth and permeability of the formation. These parameters affect reservoir pressure, reservoir productivity, number of wells required and ratio of cushion to working gas.
- Capacity of the facility. A larger storage volume will yield higher return, hence offsetting capital cost.
- Maximum withdrawal rates. Investment costs are normally higher for higher withdrawal rates.

New horizontal drilling technology has increased deliverability, at a cost. This has a greater impact, on the investment costs, for converted aquifers than for depleted reservoirs. Horizontal wells can be used to enhance well productivity by a factor of 1.5 to 6, compared to vertical well productivity; and can also minimise water coning during operation. The cost of a horizontal well is generally higher, approximately 1.3 times that of a vertical one and horizontal wells are considered more profitable for depleted reservoirs, than aquifers. Horizontal well technology is being utilised more and more frequently and has resulted in a decrease in the number of wells required for UNGS development.

A comparison of the costs levels between the USA and Europe (Table 3.12) indicates that there is little difference in capital costs and deliverability costs, for converted aquifers and depleted reservoirs[5]. Also there is an indication that investment cost in the USA is significantly lower than in Europe, but it should be noted that this comparison is based on limited information from European UNGS operators.

Table 3.12: Comparison of investment costs between Europe and USA, for storage size $100x10^6$ m^3

Type	Investment cost/working gas (USD/m^3)		Cost/deliverability (USD/m^3)	
	Europe	USA	Europe	USA
Aquifer	0.35 – 0.6	0.14*	35 – 60	10
Depleted reservoir	0.35 – 0.6	0.12	35 – 60	5

* Size $500x10^5$ m^3

3.4.4 GCS screening and site selection

Experience from the oil and gas industry on site selection is directly applicable for CO_2 storage. The main aspects that will play a significant role in the selection of sites for geological CO_2 storage are:

- Containment and geomechanics (eg, impermeable caprock, appropriate temperature, pressures and porosity).
- Economics, eg, EOR, existing infrastructure (injection wells, etc), GCS ownership
- Future competition with natural gas underground storage.

- Legislation.
- Safety, environmental issues and public acceptance.

These are discussed below.

Containment and geomechanics

The site selected should have the correct characteristics to store supercritical CO_2 in large quantities for thousands of years. These characteristics are as follows.

Impermeable caprock

A key factor for long-term safety is the quality of the reservoir caprock. Storage formations with thick caprocks will be required, preferably with additional caprocks above the reservoir caprock to minimise leakage risk.

This concept of multiple barriers is common practise for the deposit of wastes. In sedimentary basins deep saline aquifers are often overlying by an alternating succession of aquifers, which could be used to take up escaping CO_2 from the deep aquifer. However, this reserve aquifer should be located deep enough to prevent rapid gas expansion of supercritical CO_2.

From the leakage incidents identified, most or all containment breach incidents (excluding wellbore leakage), occurred in converted aquifers and were caused by caprock flaws. Although a large anticlinal structure is an important criterion for gas storage in aquifers, it introduces a greater possibility of caprock flows and potential leakage. Hence, for CO_2 storage it may be advisable to avoid aquifers with significant structural features[6]. Gently sloping structure and caprock formations may be preferable for long term CO_2 storage.

Caprock integrity assessment techniques, described in Section 3.4.2, are also applicable for GCS. In addition to these techniques, CO_2 can be used to test formation integrity, as once injected, it is not anticipated to be withdrawn at a later stage.

In-situ characteristics

Formation selected should have appropriate reservoir temperature, pressure, volume and porosity. A large reservoir will be required to store supercritical CO_2. Various studies[2, 3] assume that for aquifers, CO_2 will become supercritical at depths of approximately 800m (CO_2 critical point at 73.82 bar and 31.04^{0}C). Although this is a useful approximation, as formation temperature and pressure play an important role, supercritical status can be reached at various depths. In general, low thermal gradient and high pressures will maximise storage of supercritical CO_2. Injection in formations with pressures lower than required for supercritical CO_2 will result in CO_2 changing phase to gas (more buoyant) phase and potentially lead to rapid rise through the sedimentary formation.

Trapping mechanisms for GCS

The main mechanisms for saline-formation trapping mechanisms are:

- CO_2 dissolution into formation water. CO_2 is soluble in water and to some degree in brine, depending on salinity, pressure and temperature. Injected CO_2 will dissolve into water until equilibrium is reached. Post-injection, CO_2 migrates vertically to the top of the formation until it reaches a barrier (caprock). The formation-water interface between the caprock and formation water is likely to become saturated with CO_2. As denser CO_2-saturated water is located above virgin water (or unsaturated water), density driven currents under the caprock are likely to occur.

- Mineralisation as CO_2 precipitates into CO_2 rich minerals. When CO_2 dissolves in water carbonic acid forms which could dissolve certain minerals in the rock matrix and result in precipitation. This mineralisation process could eventually lock up CO_2 permanently into the formation. Time required for successful storage is debatable, but it is anticipated to be thousands of years.
- Gas-water relative permeability hysteresis. Sequestration by this method is mainly a post injection process. Post-injection, buoyancy is the main force acting on the injected CO_2, leading to CO_2 migrating up-dip. Two relative permeability states are present in the migrating plume. At the top of the plume, imbibition relative permeability is present as water is displaced by rising CO_2. At the tail of the plume, imbibition relative permeability is prevalent as water imbibes behind the migrating plume. In the imbibition process some CO_2 is trapped in the pore space, effectively sequestering the CO_2 in the rock until the immobile gas dissolves over time.
- Hydrodynamic trapping of mobile CO_2 beneath an effective geological seal.

<u>Seismic activity of the area</u>
Sites with high seismic activity, or sites where CO_2 injection could trigger an earthquake, are not considered suitable for GCS.

Economics

The main issues that can influence GCS are:

- EOR will be the most economic solution for CO_2 storage. As a result of injection some of the remaining oil will be mobilised and could provide income that could help to offset the cost of storage. High oil price will increase significantly EOR profitability and hence, further reduce the cost of storage. Conventional methods of oil production, recover approximately 30% of the original oil in the reservoir. EOR, principally with water flood can increase secondary recovery rates by 60-70%. Tertiary recovery techniques, such as CO_2 flooding has been used in parts of the USA. Also, using CO_2 for EOR will free up large amounts of natural gas currently used for oil production. However, some oil reservoirs will be more economic than others for CO_2 flooding, depending on intrinsic reservoir and oil characteristics and CO_2 miscibility. Therefore, these reservoirs should be used first for CO_2 storage. Consideration should also be given to costs associated with EOR for offshore locations. Excessive cost and restricted access has hindered offshore EOR to date.
- EGR. Injection into depleted gas reservoirs to maintain or increase pressure is technically feasible, although it is not normal practice. Enhanced gas production of nearly depleted gas fields is not anticipated to be the driving factor, for CO_2 storage. However, it could help to offset some of the CO_2 storage costs. Eventually, CO_2 will break through into the produced gas and CO_2 clean-up equipment would have to be installed, hence increasing CO_2 storage costs.
- GCS facility infrastructure. The capital cost will be the most expensive cost component of a CO_2 underground storage project. Existing facilities in depleted reservoirs could be

more cost effective than developing an aquifer, despite reservations made[5] (see Section 3.4.3). However, a cost assessment of the various options will be required.

Future competition with natural gas for storage formations

Future competition of GCS projects with natural gas storage is more likely to exist in countries with little underground natural gas storage infrastructure. In the USA for example, there is a general consensus[4] that currently, there is sufficient storage capacity to cover demand under normal conditions. In the UK however, the increased dependence on natural gas imports, the growth in natural gas demand and the need for supply flexibility, are anticipated to increase demand for natural gas underground storage facilities.

Most of the existing storage reservoirs throughout the world are designed to meet peak gas demands. Current economic conditions dictate that storage facilities are increasingly expected to meet high daily or even hourly swings. Therefore, storage reservoirs with high injection and withdrawal capabilities are becoming the main choice of many storage operators. Mainly, salt caverns are associated with high deliverability on demand and an increased demand in salt caverns is anticipated.

Similarly for the UK, natural gas storage growth is anticipated to concentrate mainly on salt caverns and high deliverability depleted oil and gas reservoirs within reach of major centres. No evidence could be found that aquifers will be used in the UK, in the foreseeable future, for natural gas storage.

As demand for natural gas storage increases, CO_2 storage is expected to be forced to the more remote sites, mainly offshore, increasing CO_2 storage cost. Therefore, aquifers and remote North Sea depleted hydrocarbon reservoirs are considered to be less likely to be used in the near future for natural gas storage; and hence are considered more appropriate for CO_2 storage.

Assuming future competition for underground storage space, potential exists for simultaneous CO_2 and natural gas storage at different levels in the substrata, within the same area. There is very little, relevant information from existing UNGS facilities, with the exception of the Sleipner field, where CO_2 from gas production is injected into an underlying aquifer (Utsira sand). In a similar scenario, natural gas could be stored below or above an aquifer, where CO_2 is injected. Any leaking gas from an underlying UNGS reservoir could be trapped by the overlying aquifer used for CO_2 storage. However, if the GCS aquifer is below the UNGS reservoir, any CO_2 leakage could accumulate into the overlying UNGS reservoir. This will primarily affect gas quality and depending on the CO_2 leakage into the UNGS reservoir, CO_2 induced corrosion of wells, pipelines and over-ground equipment could occur.

Legislation

Legislation and consequently requirements for the development and operation of aquifers and hydrocarbon reservoirs can influence site selection (see Section 3.2.4). In European legislation for natural gas storage there is greater demand for detailed analysis of aquifers than of hydrocarbon reservoirs.

Safety, environment and public acceptance

Safety and environmental issues (see Section 3.6.4) could influence site selection, however, not to the extent of natural gas storage projects, due to the benign risk associated with CO_2.

However, public opposition is very likely to affect site selection, mainly for onshore GCS projects. Strong public opposition can determine the fate of a CO_2 storage project. Experience from natural gas storage projects, especially in the USA and also Europe, indicate that public opposition is likely to occur during GCS site selection, especially if the proposed site is near a residential or public area. Initially, North Sea reservoirs will probably be more acceptable to the public than onshore reservoirs. Especially for onshore GCS reservoirs, the benefits of CO_2 storage should be communicated to the public at an early stage, in order to increase the chances of achieving public acceptance.

Depleted reservoirs versus aquifers for GCS projects

There are many similarities between the CO_2 storage and natural gas storage. Most of the advantages and disadvantages associated with the selection of depleted reservoirs or aquifers for UNGS (see Sections 3.4.1 and 3.4.2) are also applicable to GCS. Table 3.13, summarises the advantages and disadvantages of depleted reservoirs and aquifers for GCS.

North Sea platforms in depleted reservoirs could be an ideal candidate for GCS projects for the following reasons.

- Existing installations may only have to be reconditioned for CO_2 injection. It is important to note however, that delaying CO_2 injection from existing platforms in depleted reservoirs could bring structure and equipment into disrepair and could significantly increase capital costs.
- Containment of the depleted reservoirs has been proven and operators have a good knowledge of the site.
- EOR or EGR will increase oil or gas production.
- Future competition for geological space, for carbon or gas storage use, is more likely to be for onshore or near-shore reservoirs than far-field North Sea offshore reservoirs. Onshore reservoirs are more likely to be used for natural gas storage than for CO_2 storage.
- Far-field North Sea offshore reservoirs are unlikely to be near a water aquifer used for drinking water or irrigation in the UK. Hence, drinking water pollution may not be a major concern in these areas.
- The public will not be affected or endangered by any potential CO_2 leakage and minimum so less public opposition could be anticipated for offshore GCS projects.
- Small CO_2 leakages (eg, 1%) into the bottom of the sea, are not anticipated to have adverse effects; and carbonate compounds formed by CO_2 dissolving into water, may directly benefit organisms (see Section 3.6.4). This CO_2 retention by the seawater, could also be taken into account when adjusting for carbon tax credits, following a minor CO_2 leakage.
- Monitoring of the stored CO_2, using seismic techniques will be cheaper for offshore locations, than for onshore sites and ROVs could be used to detect small seabed leakages (see Section 3.5.4).

- The main concern with GCS is caprock leaks, as large quantities of CO_2 could migrate to surface. Caprock leakage in depleted reservoirs is a very rare event, with only one UNGS caprock leakage incident identified in 90 years. Therefore, depleted reservoirs can be considered less likely to result in a significant CO_2 leakage.
- Existing UNGS legislation could be adapted easier for offshore sites than for onshore, especially if CO_2 injection is not considered 'dumping of waste' when used for EOR. In this case, GCS does not fall within the definition of 'dumping' and could be permissible under the London Convention. Even, if it is considered 'dumping of waste', CO_2 injection could be allowed under the 'force majeure' (see Section 3.2.4), assuming the definition of 'stress of weather', when the safety of human life is threatened, includes climate change from greenhouse gases (eg, CO_2).

Table 3.13: Advantages and disadvantages of formations, from a CO_2 point of view

	Depleted oil and gas reservoirs
Advantages	• Proven containment and good knowledge of the geology, minimising risk of leakage through caprock. • Existing wells, infrastructure and gas distribution network that can be used for CO_2 injection, potentially reducing capital costs of CO_2 injection. • In the medium to long term CO_2 may react with the formation to block CO_2 permanently and further seal the reservoir. • EGR. Gas fields tend to be more widely distributed than oil fields and CO_2 can be injected at the base of the gas field to increase gas production. Injection into depleted gas fields, to maintain or increase pressure is technically feasible, although it is not normal practice. • EOR could be used to drive oil, hence generating revenue through CO_2 storage. So far there are no records of leakage through the caprock, during EOR operations. The relevant advantages of using CO_2 as a fluid for EOR are: - Reservoir pressure can be kept lower, reducing risk of caprock fracture and energy required for CO_2 injection. - CO_2 is easily dispersed in the reservoir, enhancing oil recovery. - Operators have better control of pressures and where the CO_2 goes. Also the gas oil ratio can be more easily managed. - CO_2 may dissolve the reservoir rock, enhancing permeability and releasing stranded oil. However, CO_2 dissolution and precipitation, especially in carbonates, could occur over time, which could result in reduced permeability.
Disadvantages	• Often depleted reservoirs are old and existing infrastructure requires significant maintenance and monitoring to ensure that leakages, especially through wellbore, are minimised. • Existing infrastructure is not originally designed for CO_2 and has to be upgraded at an extra cost. • Asphaltenes can build up causing formation damage around the injection/producing wells. • CO_2 can lower pH of formation, mobilising metals that were previously stable. • During EOR scale deposition, due to CO_2 reaction with minerals and formation water, can result in inefficient oil sweeping.
	Aquifers
Advantages	• Slow interaction of CO_2 with aquifer, could neutralise CO_2 over a long period of time. CO_2 can react with the formation and form carbonates that will lock CO_2 permanently. • CO_2 will dissolve in water and hence it will leak out as fast as the water moves out of the aquifer. In some aquifers water is believed to move out at a very slow rate. • Aquifers are widespread and occur around the world, hence reducing transport costs. • Deep aquifers are typically not very hydro-geologically active. • Saline water is not potable; hence CO_2 does not affect its quality. • CO_2 in water forms carbonic acid which could dissolve various minerals in the rock matrix and in the event of a small leakage, some minerals will be carried over to overlaying formations. In small quantities these can be beneficiary for controlling aquifer

	pressure and enhancing local flora. Therefore, a non-migration requirement may not be necessary for a CO_2 storage project in brine aquifer. • Open aquifers are every extensive and flat and more likely to be considered for offshore CO_2 storage. Closed aquifers have defined boundaries, produced by geological folding, faulting or both, and are more likely to be acceptable in onshore locations. The most suitable of unconfined aquifers will be those with slow moving water (eg, 1-10cm/yr) and vast capacities. In these aquifers lateral migration of CO_2 will take thousands of years before reaching the boundaries of the aquifer and dissolution/density increase in the water will slow the advance of CO_2 saturated water to some extend. Suitable aquifers should have a low permeability caprock to reduce CO_2 leakage. • Aquifers are typically too shallow for the production of geothermal energy.
Disadvantages	• High level of geological risk, as the containment of aquifers has not been proven. The risk of a substantial reservoir leak exists. • Takes more time to develop as there is little information on the site beforehand. Hence, it can be more expensive when compared with a depleted hydrocarbon reservoir. • Supercritical CO_2 is a very good solvent and carrier of minerals and potentially could carry heavy metals or natural radioactive substances to surface.

3.5 UNGS monitoring, inventory verification, leakage detection, remediation and GCS applicability

The key to successful gas storage is to ensure that injected gas remains in the intended formation and no gas can escape. The majority of the UNGS facilities use reservoir simulation models and well logging. However, a number of techniques[6] have been developed by the gas storage industry to ensure gas containment and are described in the following sections.

3.5.1 Monitoring

Monitoring consists of recording data and comparing information against set values. For example, gas losses through corrosion spots or casing collars could be detected by detecting rising annulus gas pressures, temperature, noise, neutron logs in wells, or even pressure comparison with neighbouring wells. There were cases when leakage occurred due to inappropriate characterisation of the geology of the site or high storage pressure, which allowed horizontal and vertical gas migration. A carefully designed monitoring program would detect the leaks at an early stage, before a large volume of gas is lost from storage.

Several gas monitoring techniques exist and are summarised below.

Observation wells

Observation wells monitor gas within the injection area and also beyond the intended areas. They can be very sensitive to gas leakage and are more effective than eg, pressure and volume measurement in identifying a leak.

Observation wells (see Figure 3.5) monitor mainly, pressure, by recording water level changes and can be classified as:

- Reservoir observation wells. These can be injection/withdrawal wells that are shut-in and used for reservoir pressure measurement.
- Caprock observation wells. These are completed in low permeability formations and although they cannot sense fluid movement, they can be used to detect small changes in pressure. Gas storage operators debate the usefulness of these wells; however, they are thought to be useful during initial development of aquifer storage reservoirs, particularly during a pump test.
- Water observation wells. These wells monitor water pressure in the water zone below the gas bubble or the water zone above the gas reservoir. The observation wells completed in the water zone above the gas reservoir could be used to indicate pressure changes caused by wellbore or caprock leaks.
- Spill point observation wells. These are water observation wells placed eg, at the spill points of an aquifer and are used to monitor gas leaks through the most likely spill points.

Well logging

The main purpose of well monitoring is to identify potential gas leaks from the casing or through cement faults. Permanent pressure and temperature sensors or fibre optics inside the wells are used, for real time temperature and pressure logging measurements. Neutron logging is used to identify any gas migration out of the gas storage area. New logging tools, such as nuclear magnetic resonance (NMR) could be used to improve measurements and assess fluids in porous reservoirs. Corrosion logging is used to identify corrosion problems and if necessary corrosion chemical treatment is performed. Also annulus pressures are monitored on a regular basis. If pressure is found to be high then gas and volume analysis is required to identify the source of the gas.

Seismic monitoring and reservoir simulation

Logging information, seismic explorations, geostatistics and fluid flow simulations have been utilised extensively to describe the geometrical characteristics of the formation. The seismic measurements allow the limits of the gas bubble in the reservoir and its development between two measurements to be determined and also assist in refining the reservoir simulation model. Most importantly seismic monitoring can assist in:

- monitoring small scale discrepancies (eg, faults with little slip),
- monitoring the progression of the gas bubble towards the critical spill points in several directions in order to maximise the filling of the reservoir,
- identifying gas liquid interfaces and lateral variation in strata (stratigraphy),
- identifying areas with large accumulations of gas, so that further production wells may be drilled if required,
- refining the reservoir simulation model and improving production predictions.

Two-dimensional (2D) seismic imaging, three-dimensional (3D) seismic imaging, time-lapse (4D) seismic and high resolution seismic methods can be used to accurately map an area and also monitor the expansion of the injected gas over a pre-specified period. Seismic methods are not widely used in the UNGS industry and from information available, when used, it is mainly 2D seismic and occasionally 3D.

4D is a relatively new technique and has been used successfully on the Sleipner field; however, 4D will be more useful for offshore aquifers, as it will be very expensive on land. High resolution seismic is rarely used on land. The use of precision seismic exploration (eg, 3D, 4D) offers the following advantages:

- allows uncertainties to be minimised,
- reduces number of wells drilled required for the certification,
- permits storage wells to be better located within the reservoir, therefore lowering number of development wells required,
- assists in describing geometric characteristics and petrophysical properties of reservoirs.

Fluid flow simulations have improved significantly due to:

- advances in knowledge and models of fluid flows in underground storage facilities,
- falling cost of simulation,
- increased performance and reduced costs of computers.

Fluid flow simulations give a clearer picture of underground gas distribution at any moment and any place. Therefore, working volumes, peak withdrawal rates, number and location of new wells required and minimum cushion gas required can be assessed.

4D microgravity

Microgravity is the measurements of extremely small variation in gravity associated with density variations in the subsurface. Time-lapse microgravity measurements can give a dynamic picture of the subsurface and fluid flow. 4D microgravity has been tested with some positive feedback. However, this technique can be susceptible to earth tides, changes in water table, subsidence and more work is required.

Vegetation monitoring and gas detection

A vertical gas migration, reaching the surface could result in:

- high gas content in soil,
- damage to vegetation,
- gas breaking out of water creating visible bubbles and potentially affecting drinking water,
- gas accumulation in enclosed areas, such as basements.

Gas can be monitored by soil monitoring and aerial observation of affected vegetation that could have stunted growth. Where water is present, gas can be readily observed and gas detectors can be located near wellheads, formation faults or basements. Vegetation monitoring for gas detection is rarely used in UNGS facilities and only a few examples are known.

Tracers

Using a tracer, i.e. mixing a small quantity of an easily detectable gas with CO_2, could help in detecting CO_2 movements across the reservoir and formations and ascertaining its origin.

3.5.2 Inventory verification

The main gas inventory verification techniques utilised by the gas storage industry, are described below.

Pressure-volume techniques

Pressure-volume techniques include material balance calculations which can be used to calculate remaining gas. Pressure and volume data are recorded and compared against material balances on a seasonal or annual basis. Pressure-volume calculations can give an indication of the stored gas but cannot be used to detect small leaks. Also reservoir simulation models can be used to assist with inventory verification.

Volumetric techniques

Volumetric techniques are more useful for aquifer fields where movement of water complicates the pressure-volume calculations, especially during the early injection stages, where the gas bubble has not fully developed. This technique estimates the pore space, water saturation and thickness of the gas bubble. Data is derived from core samples and well logs and cannot be used to accurately describe the reservoir. However, this technique is useful during the early stages of an aquifer development, where the gas bubble has not been formed and the pressure-volume technique cannot be used.

Seismic imaging

On a large scale, 3D and 4D techniques can also be used to verify the gas inventory. Seismic imaging can be limited by excessive costs, especially for onshore applications.

Gas migration monitoring

Assuming that no gas escapes from the reservoir, the volume of the gas in the reservoir is the same as the volume of the injected gas. This technique requires the monitoring of gas movement and the following should be monitored (Figure 3.5):

- formation around the intended reservoir,
- wellbore leaks, by well logging programs and monitoring annulus pressures,
- caprock, by monitoring gas pressure in the overlying water zones by observation wells,
- gas movement in the water baring zone under the reservoir by using observation wells.

This technique is more sensitive than volumetric and pressure-volume techniques and sometimes more than one technique are required to assure gas is not leaking.

3.5.3 Leakage detection and remediation

Monitoring and inventory verification techniques stated in Sections 3.5.1 and 3.5.2 above, can be utilised to detect gas leakages. However, small gas leakages, escaping through migration paths to surface, may not be detected in time and could result in explosion, fire or asphyxiation in enclosed areas.

Gas leaks from the wellbore could be readily repaired with standard oil and gas techniques.

Gas from a leaking caprock is likely to migrate to shallower formations, until it reached another caprock that does not leak. Shallow wells can be drilled to recover gas from the shallow zones. Also, gas withdrawal could be used to minimise reservoir pressure, hence reducing further gas leakage to shallow zones. Detailed seismic studies will be required to establish the shallow zones where the bulk of the gas has accumulated and multiple shallow wells maybe required to recycle the shallow gas.

Another technique used for controlling migrating gas is the continuous withdrawal of water below the gas bubble. Withdrawal of significant volumes of water lowers the pressure in the gas storage zone, hence reducing gas leakage through the caprock. This technique has been put in practise at one Midwestern gas storage field and continues to be utilised.

After implementation of a gas recycle program or pressure control procedure via water withdrawal, steps should be taken to minimise leakage by:

- Minimising reservoir pressure to below original reservoir pressure. This is essential in the case of an aquifer field.
- Minimising the duration of maximum pressure in the reservoir. This can be achieved by delaying injection during the injection season and withdrawing early during the withdrawal season.

The leakage detection and remediation program used for a gas leakage from the Mt. Simon aquifer reservoir provides some useful insight into the above techniques.

Mt. Simon aquifer was developed in early 1960's and following gas migration to the surface, several shallow gas wells were used successfully to withdraw shallow gas and control the leak. It has been speculated that faulting or minor fracturing of the caprock was responsible for the gas migration and several tests were performed to identify the leak source, including the following.

- Tracer surveys. Several different radioactive tracers were injected into different sections of the gas reservoir, but no tracer was found in the shallow produced gas.
- Seismic data analysis. The aim was to identify any faults and drill a well to that particular location to produce gas if possible, hence minimising upward migration to the surface. Another possibility was to use the well for some type of 'squeeze job' using either cement or foam to seal or reduce the gas migration. However, 1970's seismic technology was not detailed enough to locate any faults or fractures with enough confidence to drill a well.
- Controlled injection and withdrawal. Preferential injection or withdrawal from certain areas of the field was performed, in order to identify which area had more impact on the gas migration. Here again the conclusion was uncertain.

3.5.4 Monitoring, leakage detection and remediation for GCS

CO_2 monitoring and leakage detection

Monitoring is very important for a GCS project and it aims to:

- ensure safety of storage project and identify potential leaks,
- verify quantity of CO_2 injected, for accounting purposes,
- assess whether storage capacity is being used effectively,
- ensure effectiveness of EOR (where appropriate).

Monitoring and inventory verification techniques utilised by natural gas storage operators can be used directly to monitor and verify CO_2 inventory and also detect any CO_2 leakages. Monitoring of a GCS project can be split into short term monitoring and long term monitoring, hence allowing monitoring requirements to be defined.

<u>Short term monitoring</u>

Monitoring of CO_2 during injection will be required, as it is very important to ensure the containment of the injected CO_2 and identify potential leakages at an early stage. Similarly to

UNGS projects (see Section 3.5.1), the following monitoring and inventory verification techniques can be used for short term monitoring:

- Observation wells. Especially for aquifers, observation wells can be used to monitor the CO_2 behaviour, spill points and also water zones below or above the reservoir for any signs of CO_2 leakage. For depleted reservoirs, even through are not generally required by legislation, many UNGS operators have observation wells and consideration should be given on a project by project base. Monitoring CO_2 movement around the intended reservoir, can provide assurance that if no CO_2 is detected, then all CO_2 injected has been successfully trapped. The exact location of the observation wells can be obtained by a combination of reservoir modelling, 3D seismic, electrical imaging and gravity surveys.
- Well logging, ie, temperature, pressure monitoring and neutron and corrosion logging.
- Seismic imaging (eg, 3D and 4D). Unmapped spill points may exist with hydraulic continuity away from the aquifer. Therefore, seismic monitoring is more appropriate for aquifers. Seismic monitoring may not be necessary for oil and gas reservoirs, where containment is proven. It should be noted that seismic reflection surveys may not always be so successful; costs for these surveys are high and in some cases the spatial resolution or the detection threshold may not be adequate.
- Remote sensing of CO_2 using satellites. This is very complicated due to the long distance through the atmosphere over which CO_2 is measured and the atmospheric CO_2 fluctuation.
- Electrical imaging and gravity surveys.
- Land-surface deformation. Surface deformation can be measured by satellite and tiltmeters placed on the ground surface which can measure changes in tilt of a few nano-radians. Taken separately or together these measurements can be inverted to provide a low-resolution image of subsurface pressure changes. However, these technologies are new and have been used only on a few monitoring programs.
- Reservoir simulation.
- Vegetation monitoring and CO_2 gas detection. Detection of small CO_2 leakage to surface will be difficult, as there is no reliable CO_2 detection measure that could adjust for background CO_2 emissions. CO_2 readings can be taken before injection and used for comparison against post injection CO_2 readings. Minor CO_2 leakage could improve vegetation and although it could be a sign of potential CO_2 leakage, the environment is not affected. CO_2 detectors could be located near wellheads, formation faults and enclosed areas (eg, basements), and are anticipated to be useful mainly for detection of a large leak.
- Vadose zone and soil monitoring for CO_2 concentrations using soil gas surveys and vadose zone sampling wells and gas composition analysis.
- Tracers could be used to enhance detection sensitivity.
- For offshore wells, divers and remotely operated vehicles will be required for inspection. Also, geophones could be used to listen for CO_2 bubbles.

<u>Long term monitoring</u>

Post injection monitoring could potentially run into thousands of years and will be required for two reasons:

- To ensure that no CO_2 leaks from the reservoir over the years, mainly from the wellbore and also from the reservoir.
- To identify when CO_2 monitoring is no longer required. Injected CO_2 may be held in the formation as follows: in an aqueous phase, dissolved in brine; in solid minerals resulting from the reaction of CO_2 with formation rock or waters, or bound onto hydrocarbons, particularly asphaltenes and bitumens. When CO_2 is fixed in location, no further monitoring will be required.

Post CO_2 injection, the main monitoring methods could be based on:

- Surface monitoring and land-surface deformation.
- Vadose zone and soil monitoring for CO_2 concentrations.
- Divers, remotely operated vehicles and geophones, for offshore wells.
- Observation wells.
- Geophysical surveys (eg, seismic monitoring).

Maintaining an observation well over thousand of years can be very challenging from an economic, ownership and legal point of view (see Section 3.2.4). Existing well construction materials are designed for operation over tens of years and not over hundreds or thousands of years (see Section 3.6.1). Leakage incidents identified were predominately the effect of leaking wells; therefore, consideration should be given to the need for observation wells for long term monitoring.

Alternatively, observation wells could be used for a relatively short period of time, post CO_2 injection, eg, 50-100 years; to ensure that CO_2 movement in the reservoir has stabilised and no leakage has occurred. Then, if CO_2 appears to be stabilised and there are no signs of loss of containment, observation wells could be plugged and abandoned. Following plugging and abandonment of the observation wells, monitoring could take the form of periodic geophysical surveys (eg, seismic imaging, electrical imaging and gravity surveys), reservoir modelling and surface monitoring.

This approach could assist in:

- Fixing the risk to GCS operators to a specific period of time, hence encouraging operators to undertake GCS projects.
- Reducing the maintenance costs associated with observation wells, especially if required over thousands of years.
- Reducing the potential of CO_2 leakage through the wells (assuming plugging methods are suitable for GCS).

<u>Monitoring requirements</u>
Monitoring requirements need to be set on a project (local) scale and also a global scale.

On a project or local scale, short term and long term monitoring requirements could be set, as proposed in the sections above. When setting the monitoring requirements consideration should also be given to the size of local population (if any). If a GCS project was located near an urban area, extra precautions would be required compared to a remote offshore location project. For example, remote offshore GCS projects may require minimum post-injection monitoring (eg, mainly ROV and geophone monitoring) compared to onshore projects near urban areas where seismic monitoring may be required to provide an early warning of loss of containment.

On a global scale, monitoring will provide assurance that CO_2 emission reduction goals are being met. Any significant CO_2 leakage will counteract any greenhouse benefits gained during CO_2 storage. A national and international set of CO_2 reporting and monitoring standards will be required to ensure consistency in CO_2 accounting throughout the nations.

Non-migration type approach

In the USA the movement of injected fluids in an underground source of potable water is explicitly prohibited for class I-III wells. No federal requirement exists for observation wells or even monitoring for detecting leakages. Therefore, the non-migration policy is based on a complaints system, eg, detection of injected fluids into a drinking water aquifer and not a proactive system where a leakage is identified at an early stage, allowing remediation to be taken.

A similar approach adopted for GCS will encourage operators to undertake GCS projects. However, the main disadvantage of the non-migration approach is that it may require a consequence (eg, environmental, health) for a reservoir leakage to be detected.

Assuming the GCS reservoir is in a remote offshore location, then the impact of a small reservoir leak is likely to be minor and the non-migration approach could be considered. However, for onshore GCS projects, especially near an urban area, a reservoir leak could have significant consequences and therefore, the non-migration approach will be difficult to justify and some form of post-injection monitoring is likely to be required.

CO_2 leakage remediation

Wellbore leakage

Most gas leakage incidents in UNGS facilities are associated with defective wellbores, especially with poor cement jobs, improperly plugged wells and corrosion. Cementing casing and plugs have to withstand thousand of years and existing cement technology can not guarantee this. However, existing technology can successfully identify and seal a wellbore leak.

Caprock leakage

From the remaining caprock leakage incidents, information from CCP[6] indicated that all geological controlled gas migration problems have occurred in aquifer reservoirs. Caprock leaks are more difficult to be dealt with and some experience exists from aquifer reservoirs. In the 1970s, there was an attempt to locate a caprock leakage, with the intention to seal the leakage; however, no documented cases of successful sealing of leaking caprocks exist. There have been significant advances in seismic technology since 1970s and 3D, 4D, high resolution crosswell and vertical seismic profiling could assist is directing a wellbore to a specific location. Research[6] has been performed on foams and other materials to control the leak through a geological fault or fracture.

Vadose zone remediation of CO_2

CO_2 leakages to the vadose zone can be treated similarly to leakages of volatile organic components (VOC) to the vadose zone. Information obtained from LBNL[156], indicated that standard passive and active vadose zone remediation techniques can be used for remediating CO_2 leakage plumes in the vadose zone. In more detail:

- Barometric pumping enhances the removal rate of CO_2.
- Passive CO_2 removal from high-water saturation regions near the water table is limited by low gas saturation and high solubility in groundwater.
- For vapour extraction using a vertical well, the well screen should not be too close to the water table.
- A combination of an impermeable cover and vertical well will improve the removal rate of CO_2 if the well screen is relatively shallow.
- The combination of horizontal and vertical wells is more effective than having one or the other.
- Permeability anisotropy results in a faster removal rate at an early stage and slower rate later on.

Remediation options for leaking geological projects

In summary, the following CO_2 leakage scenarios (see Figure 3.4), that may require remediation, can be envisaged:

- Leakage from the storage reservoir.
- Leakage through an active or abandoned well.
- Leakage that has reached shallow groundwater.
- Leakage that has reached the vadose zone and has affected the soil.
- Atmospheric CO_2 leakage from large releases to the surface.
- Low level leakage that has accumulated in buildings.
- Leakage that has reached surface water.

Research detailed in the CCP report[20] provides the following remediation options (see Table 3.14 to Table 3.20) for the above leakage scenarios. In some cases the methods are well established. In others, they are more speculative, but may nevertheless one day become useful.

Table 3.14: Options for remediation of leakage from the storage formation.

Leakage Point	Remediation Options
Storage Reservoir	• Lower injection pressure by injecting at a lower rate or through more wells • Lower reservoir pressure by removing water or other fluids from the storage structure • Intersect the leakage with extraction wells in the vicinity of the leak • Create a hydraulic barrier by increasing the reservoir pressure upstream of the leak • Lower the reservoir pressure by creating a pathway to access new compartments in the storage reservoir • Stop injection to stabilize the project • Stop injection, produce the CO_2 from the storage reservoir and reinject it back into a more suitable storage structure

Table 3.15: Remediation options for leakage from injection and abandoned wells

Leakage Point	Remediation Options
Active or abandoned wells	• Repair leaking injection wells with standard well recompletion techniques such as replacing the injection tubing and packers • Repair leaking injection wells by squeezing cement behind the well casing to plug leaks behind the casing • Plug and abandon injection wells that can not be repaired by the methods listed above. Rules for well abandonment are region specific, but in all cases involve either plugging the well with cement, or plugging parts of the well with cement. • Stop blowouts from injection or abandoned wells using standard techniques to "kill" a well such as injecting a heavy mud into the well casing. After control of the well is re-established, the recompletion or abandonment practices described above can be used. If the wellhead is not accessible, a nearby well can be drilled to intercept the casing below the ground surface and "kill" the well by pumping mud down the interception well.

Table 3.16: Remediation options for accumulations of CO_2 in shallow groundwater

Leakage Point	Remediation Options
Shallow groundwater	• Accumulations of gaseous CO_2 in groundwater can be removed, or at least made immobile, by drilling wells that intersect the accumulations and extract the CO_2. The extracted CO_2 could be vented to the atmosphere or reinjected back into a suitable storage site. • Residual CO_2 that is trapped as an immobile gas phase can be removed by dissolving it in water and extracting it as a dissolved phase through groundwater extraction wells. • CO_2 that has dissolved in the shallow groundwater could be removed, if needed, by pumping to the surface and aerating it to remove the CO_2. The groundwater could then either be used directly, or reinjected back into the groundwater.

Leakage Point	Remediation Options
	• If metals or other trace contaminants have been mobilized by acidification of the groundwater, "pump-and-treat" methods can be used to remove them. Alternatively, hydraulic barriers created to immobilize and contain the contaminants by appropriately placed injection and extraction wells. In addition to these active methods of remediation, passive methods that rely on natural biogeochemical processes may also be used.

Table 3.17: Remediation options for surface fluxes and accumulations of CO_2 in the vadose zone and soil gas

Leakage Point	Remediation Options
Vadose Zone and Soil Gas	• CO_2 can be extracted from the vadose zone and soil gas using standard vapor extraction techniques from horizontal or vertical wells (see Table 3.18). • Fluxes from the vadose zone to the ground surface could be decreased or stopped using caps or gas vapor barriers. Pumping below the cap or vapor barrier could be used to deplete the accumulation of CO_2 in the vadose zone. • Since CO_2 is a dense gas it could be collected in subsurface trenches. Accumulated gas could be pumped from the trenches and released to the atmosphere or reinjected back underground. • Passive remediation techniques that rely only on diffusion and "barometric pumping" could be used to slowly deplete one-time releases of CO_2 into the vadose zone. This method will not be effective for managing ongoing releases because it is relatively slow. • Acidification of the soils from contact with CO_2 could be remedied by irrigation and drainage. Alternatively, agricultural supplements such as lime could also be used to neutralize the soil.

Table 3.18: Remediation options for managing high concentrations of CO_2 from large releases to the atmosphere

Leakage Point	Remediation Options
Atmospheric CO_2 from large releases to the surface	• Large releases will be managed using techniques that are established for industrial usage of CO_2. For CO_2, because it is considered to be a non-toxic and inert gas, dilution with air is the primary method for managing a release. • For releases inside a building or confined space, large fans could be used to rapidly dilute CO_2 to safe levels. • For large releases spread out over a large area, dilution from natural atmospheric mixing (wind) will be the only practical method for diluting the CO_2. • For ongoing leakage in established areas, risks of exposure to high concentrations of CO_2 in confined spaces (eg, cellar around a wellhead) or during periods of very low wind, fans could be used to keep the rate of air circulation high enough to ensure adequate dilution.

Table 3.19: Remediation options for managing chronic low level releases into indoor environments

Leakage Point	Remediation Options
Indoor environments with chronic low level leakage	• Low level releases into structures can be eliminated using techniques that have been developed for controlling release of radon and volatile organic compounds into buildings. • The two primary methods for managing indoor releases are basement/substructure venting or pressurization. Both would have the effect of diluting the CO_2 before it entered the indoor environment.

Table 3.20: Remediation options for releases into surface waters

Leakage Point	Remediation Options
Surface water	• Shallow surface water bodies that have significant turnover (shallow lakes) or turbulence (streams) will quickly release dissolved CO_2 back into the atmosphere. • For deep, stably stratified lakes, active systems for venting gas accumulations have been developed and applied at Lake Nyos and Monoun in Cameroon.

3.6 UNGS design, operational aspects and CO_2 applicability

Design and operational aspects identified in UNGS facilities and their GCS applicability are presented below.

3.6.1 Well Design

The main factors that would affect well design for GCS projects are:

- Casing and cement required for the well's life expectancy.
- Corrosive properties of CO_2. Well materials, must be compatible with fluids with which the materials may be expected to come into contact.
- Depth of the injection zone and injection pressure.

Casing/tubing
There is no standard injection-well design. However, all such wells have similar features. A typical injection-well consists of the following concentric pipes.

- The exterior pipe, or surface casing is designed to protect freshwater in the aquifers through which the well passes and to prevent corrosion. It extends from the surface to below the base of the deepest potable water aquifer, and is cemented along its full length.
- The intermediate pipe or 'long string' casing extends from the surface through the top of the injection zone and is cemented along its full length, especially for waste injection wells.
- The innermost pipe is the injection tubing in which the gas is actually transported. A packer is used to isolate the injection zone from the casing and also assist the detection of any leakage.

In order to increase efficiency more and more UNGS wells are drilled using large diameter completion, especially when there is no production of liquid. Also, to reduce pressure drop along the production tubing, some new UNGS wells are drilled without tubing (mono-bore wells) in order to minimise gas flow perturbation. Mono-bore wells could be used for CO_2 injection, however, as there will be no tubing, wellbore containment has to be based mainly on the casing which could lead to casing leakage.

Cementing
Zonal isolation and gas tightness are the most important aims for cementing a wellbore-casing annulus and plugging a well. Especially for UNGS facilities, pressure and temperature cycling can affect the cement significantly. Conventional portland cement will shrink during settling (under tensile loading), potentially creating microannuli which could allow gas leakage to the surface or lower pressure zones.

Existing cementing technology cannot guarantee the thousands of years required for successful CO_2 storage. Conventional portland based cements or oilfield cements can be rapidly carbonated under high CO_2 pressure. Cement carbonatation can lead to strong degradation of the set cement, which could result in CO_2 leakage either to the surface or lower pressure zones.

Research[152] indicated that conventional portland based cements have a strong sensitivity to carbonatation with up to 40% of carbonatation associated with a decrease of the pH from 12-13 to 6.5-7, but without alteration process. Different types of cement are currently developed for high pressure high temperature (HPHT) wells, that could exceed the design life of portland cement by far.

Horizontal wells

Horizontal wells appeared in the 1980's mainly in oil production and since then, have been successfully used for production from many oil and gas fields.

Very few UNGS facilities around the world have horizontal wells, but this technique is expected to grow fast over the coming years. Horizontal drilling enables the conversion of depleted fields with poor petrochemical characteristics into gas storage facilities. Horizontal wells can be used to enhance well productivity by 1.5 to 6 times higher than vertical well productivity and can also minimise water coning during withdrawal. The cost of a horizontal well is generally higher, approximately 1.3 times that of a vertical one. However, horizontal wells are considered more profitable for depleted reservoirs with low permeability, than aquifers which have high permeability. Horizontal wells have resulted in a decrease in the number of wells required for a UNGS development.

Although more expensive, horizontal wells could be used for CO_2 injection, especially in converted aquifers. Installing a horizontal well will minimise caprock damage and also assist in injecting at the base of the aquifer.

Well stimulation

Stimulation activities can be used to increase storage well deliverability, however are not performed as frequently as with production wells.

Corrosion

Corrosion at injection wells will be a major concern, due to the corrosive nature of CO_2. Corrosion could be minimised by use of gas drying techniques, which could potentially increase the GCS cost.

Saline waters can also increase the rate of casing/tubing steel and cement corrosion and should be designed to the appropriate industry standards.

Well depth

Well construction costs are highly proportional to well depth, ranging from $300,000 for an average, Class I well to approximately $1 million for a deep Class I well[12]. Retrofitting an old production well into an injection well can be considered to be roughly half the cost of the construction of a new well.

3.6.2 Well abandonment

Similarly to well abandonment in the oil and gas industry, the main requirements for GCS are as follows (see also Section 3.2.4):

- All discrete permeable zones penetrated by the well should be isolated from each other and from the surface or seabed, using permanent barriers. Normally an 100ft isolation plug above and below of any transition zone, is required for wellbores in eg, depleted reservoirs. For GCS wells as the reservoir will be pressurised, a deeper isolation plug should be used, or if possible the whole wellbore should be cemented.
- Some guidelines[8], eg, do not require downhole equipment removal, provided isolations are in place. Other guidelines[9] eg, require removal of all downhole equipment and uncemented casing/tubing strings. For GCS, removal of uncemented casing and tubing strings prior to cement plug installation could reduce leakage paths to surface, from corroding tubing and casing.
- Some guidelines do not set specific requirements for containment verification. However, some minimum requirements are recommended eg, the first barrier should be tested to 500psi minimum above the leak off or estimated fracture gradient at the base of the barrier. For a high pressure well, pressure testing of the second barrier is not required, as it will be very difficult to get conclusive information.
- Careful selection of the barrier (cement) and the placement technique is required due to the high pressure and corrosive nature of CO_2.
- Records of active and abandoned wells should be carefully kept by both the operator and relevant government agent.

3.6.3 Reservoir aspects

Reservoir overpressurisation

As discussed in Section 3.1, converted aquifers used for UNGS are normally overpressurised by 30-40% above formation pressure. Depleted reservoirs normally do not exceed discovery pressure, although some UNGS operators have exceeded storage pressure by almost 90%. As the key factor for long-term safety of GCS is the quality of the reservoir rock the following should be considered:

- Maximum pressure of CO_2 injection should be below the capillary pressure of the caprock, to prevent CO_2 percolation. Even, if some leakage is allowed though the seals, the fracturing pressure of the caprock is the limiting pressure for injection of CO_2.
- Overpressurisation of depleted gas reservoir used for GCS should be avoided. Depressurisation through production and repressurisation with CO_2 above discovery pressure, could potentially fracture the caprock or create leak paths to overlying formations. If the reservoir pressure is required to exceed the initial pressure, substantial proof is required of the presence of a gas-tight caprock, especially for GCS in aquifers.

Inert gas injection as cushion gas alternative

Another use for CO_2 that could assist GCS, could be to provide cushion gas in aquifers for UNGS. Cushion gas accounts for a significant part of the development of an UNGS aquifer. Cushion gas could be replaced with an alternative inert gas such as CO_2. However, to minimise the risk of formation damage and also gas mixing, the following technological aspects have to be studied extensively[19]:

- Hydrodynamic analysis and conditions of inert injection related to storage operation or development.
- Geochemical analysis.
- Simulation studies for the optimisation of inert injection and storage operation.
- Location of inert gas wells.
- Gas mixing monitoring.
- Inert gas manufacturing technology.

The most important aspect of using CO_2 as cushion gas, is the extent of mixing with the working gas. Experimental studies on enhanced gas recovery using CO_2, have demonstrated that there is limited mixing of displaced methane with CO_2, in carbonate rock cores[62]. Also, the higher density and viscosity of CO_2 relatively to methane, is anticipated to limit mixing of the two gases.

Since 1979, Gaz de France has been using inert gas* to replace natural gas as cushion gas, in three UNGS aquifers. A very efficient measuring network and modelling tool is required to handle gas mixing phenomena and predict inert production according to different cycling scenarios and a total saving of 20% of cushion gas can be achieved.

3.6.4 Risk assessment

Major risks associated with operation of natural gas UNGS facilities, can be grouped into the following three categories.

- Safety risk. Gas migration to surface is the major concern associated with UNGS facilities. Gas migrating to surface could ignite, causing explosion and fire. Gas can accumulate in basements and enclosed areas and can cause asphyxiation.
- Environmental risk. Natural gas migration to surface is not considered a significant threat to the environment and most likely it would affect vegetation on a local scale. However, most importantly, cyclic operation of UNGS facilities can result in ground heaving, subsidence and stimulation of earthquakes in certain areas. Incidents have been reported where UNGS facilities were blamed for subsidence and earthquakes.
- Economic risk. The economic risk for an UNGS facility can range from loss of gas (valuable commodity), to remediation, compensation, litigation cost and possibly facility shut down, assuming a gas leakage with significant impact to people and property.

Risk associated with CO_2 storage is different from natural gas storage due to the benign risk associated with CO_2 and also the long duration required for successful storage. In more detail, the effects[18] of CO_2 leakage and CO_2 injection should be addressed for each specific GCS project:

- Effects of CO_2 on humans. CO_2 is an asphyxiant and respiratory problems occur at concentrations higher than 15,000ppm. High CO_2 concentrations, eg, 70,000ppm –

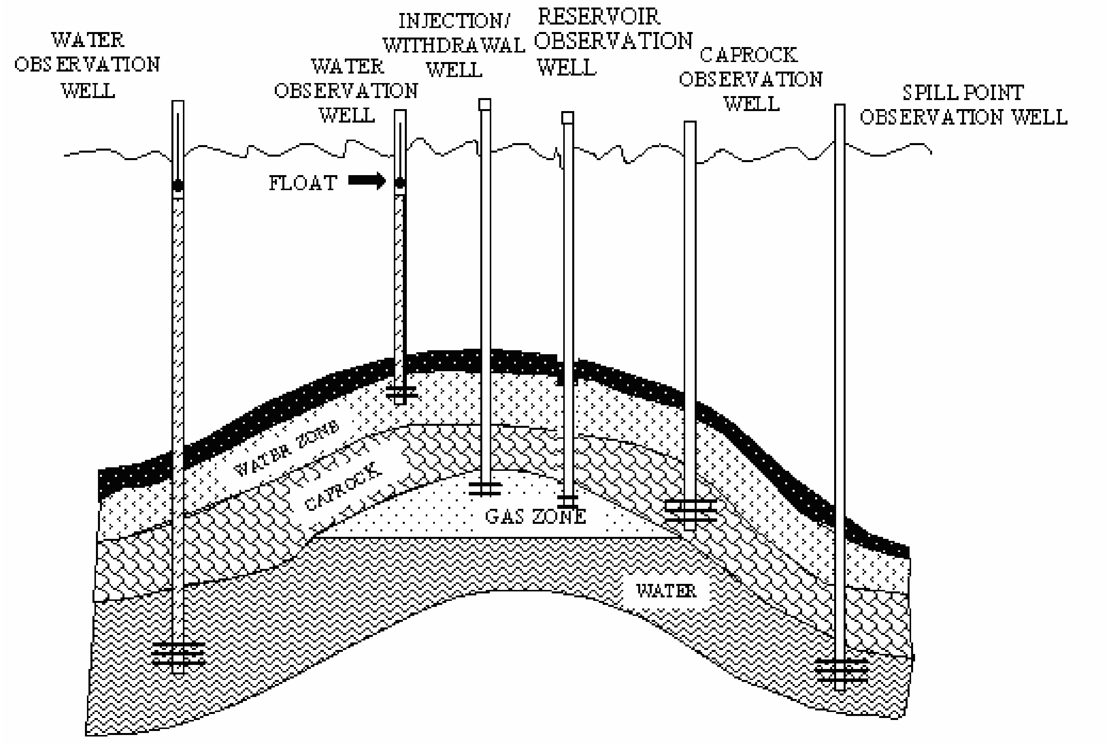
* Cushion gas used in France is believed to be flue gas, however no confirmation to this effect could be obtained.

100,000ppm (7-10%) can result in unconsciousness and dizziness within a few minutes, where as very high CO_2 concentrations, eg, 170,000ppm – 300,000ppm (17-30%) can result in unconsciousness, coma and death within 1 minute.

- Effects of CO_2 on vegetation. CO_2 is an essential material during photosynthesis and when atmospheric CO_2 doubles (from 360ppm to approx. 700ppm), vegetation production is increased by 25-40%. There appears to be little benefit in concentrations higher than 800ppm, however, it is anticipated that plants can tolerate concentrations of up to 1,000ppm. There are also reports for a selection of plants, that increased levels of CO_2 could increase plant nutritional value, by increasing photosynthesis rates and growth substrates, such as sugars.
- Effects of CO_2 on fresh water. CO_2 is chemically reactive with water and can form carbonic acid and potentially cause breakdown of the formation rock. This could lead to release of minerals that have been deposited in sediments or even naturally occurring radioactive materials, associated with the formation rock. Also change in water chemistry could have an impact on the biological integrity of water. It is suggested that optimum level of CO_2 in water is 50ppm.
- Effects of CO_2 on ground water. CO_2 in groundwater will form carbonic acid and reduce the pH of the water. Acid water may react with eg, limestone, resulting in salt formation, hence increasing ground water salinity. It is important to monitor naturally occurring CO_2, especially in areas of known CO_2 presence, in order to minimise false alerts from CO_2 in soil near a GCS area.
- Effects of CO_2 on oceans. CO_2 has the ability to dissolve into water and form, at eg, 1%, carbonic acid (H_2CO_3). This will then dissociate into carbonate ions (CO_3^{2-}). The carbonate ions can cause the precipitation of other ions in the water, such as limestone ($CaCO_3$) and dolomite (mixed $CaCO_3$ and $MgCO_3$). More CO_2 dissolving into water and forming carbonate compounds, may directly benefit organisms that use it. In the event of large leaks impacts on the marine environment can be expected.
- Effects of CO_2 on soil. Soil CO_2 levels can vary from 1% (10,000ppm) to 3% (30,000ppm). Some authors suggest that soil concentrations can easily be elevated to 10-15% CO_2 purely by enhanced activity in the carbon cycle due to availability of vegetable matter. At concentrations of 20% in soil, trees have been reported to have died, due to inadequate supply of oxygen to the roots.
- Major release of CO_2. A significant release of CO_2 following a catastrophic event (eg, earthquake) could potentially affect people, mainly in the immediate area; and possibly contribute to climate change.
- Induced earthquakes. During reservoir pressurisation with CO_2, potential exists for induced earthquakes or ground heave.

Risk criteria, similar to the HSE individual and societal risk criteria, could be set for GCS activities.

Figure 3.5: Types and location of observation wells (Gas Technology Institute, CO_2 Capture Project)[6]



4. CONCLUSIONS AND RECOMMENDATIONS

4.1 Conclusions

The following conclusions have been made:

- In Europe, the majority of the UNGS depleted reservoirs are deeper than 800m and the majority of the converted UNGS aquifers are less than 800m deep. Only a few deep aquifers have been developed in Europe and therefore competition for geological space is more likely to exist for depleted reservoirs than for aquifers.
- The majority of the depleted reservoirs and almost all converted aquifers have observation wells, possibly indicating operators' confidence in observation wells, for reservoir monitoring.
- Competition with natural gas is more likely to exists in countries with little underground gas storage infrastructure. In the USA there is a general consensus[4] that currently, there is sufficient storage capacity to cover demand under normal conditions. In the UK however, the increased dependence on natural gas imports, growth in natural gas demand and need for supply flexibility will increase demand for UNGS facilities. Future competition for geological space, is more likely to occur with onshore or near-shore reservoirs than far-field North Sea offshore reservoirs. Onshore reservoirs are more likely to be used for natural gas storage than for CO_2 storage.
- Operators in countries with experience in underground gas storage (ie, USA and Canada) operate their UNGS depleted reservoirs above reservoir discovery pressure, whereas in Europe only a few depleted reservoirs exceed discovery pressure. Increasing reservoir pressure improves deliverability in UNGS reservoirs, which is not applicable for GCS, although it will increase the amount of CO_2 stored. Therefore, increasing CO_2 storage pressure above discovery pressure, although it will increase CO_2 mass stored, could also increase the risk of caprock fracture.
- The majority of the UNGS converted aquifers operate between 20% and 40% above the aquifer formation pressure, which could be a good indication for GCS projects in aquifers.

Legislation studied from the USA, Canada and northern Europe indicates that the existing regulatory framework, with some modifications, could be used to regulate GCS projects. Some common aspects that need to be addressed and clarified are as follow.

- Generally, natural gas legislation assumes that natural gas stored underground is an expensive commodity, which must be preserved from escaping the formation. So far CO_2 is portrayed as 'waste', with the potential for polluting underground fresh water. Therefore, clarification is required on whether CO_2 can be treated as a valuable commodity or a waste.
- In the USA there is no clear regulatory requirement for reservoir leakage monitoring, i.e. there is no need for observation wells, even though the majority of the UNGS facilities in the USA (approximately 80% of depleted reservoirs and almost all aquifers) have observation wells. In Canada observation wells are required for all types of UNGS facilities. In Europe, EN1918-1/2-1998 states that observation wells are required for aquifers, but there is no clear requirement for depleted oil and gas reservoirs.

- Natural gas legislation addresses liability for environmental incidents and damage to property, mainly during the operational phase of an UNGS facility. In general, the UNGS owner is fully liable for any damage resulted from an UNGS activity and some countries have clear legislation, which assigns liability to the UNGS owner in perpetuity. However, it is evident that, after wells and site have been abandoned the government eventually assumes liability for the site, as companies have either seized operation or merged with other companies. Therefore, ownership of the post-abandonment injection wells and CO_2 injected, should be clearly defined and consideration should be given to limiting the duration of the operator liability once injection has ceased.
- Mainly for offshore installations, there is a clear requirement for post-abandonment monitoring of remaining facilities. Long term monitoring requirements should be clarified for both offshore and onshore sites.
- Duration of ownership of a post-abandonment GCS project and consequent monitoring requirements should be addressed. Reducing these requirements from perpetuity to a fixed period of time (eg, 50-100 years) would encourage GCS projects and minimise future uncertainty. Some form of insurance or bond would be required, for eg, post-abandonment well repair.
- To assist international emissions trading schemes (eg, emissions tax credit, etc), legislation should also cover future inventory verification.
- It is envisaged that there maybe difficulty in arranging an agreement between the multiple regulatory agencies at a national and also global level. Cooperation will be required at any level and a global reference standard could be useful in providing some common grounds for setting the GCS regulatory framework.

All UNGS leakage incidents identified were listed in Table 3.11. Leakage incidents identified are anticipated to represent at least all significant UNGS leakage incidents. To the degree that available information allows, the following conclusions can be made:

- Seventeen UNGS leakage incidents were identified. Nine UNGS leakage incidents were reported until the 1970s and eight between the 1980s and 2004.
- From the 1980s to date, there was one leakage incident in a depleted reservoir and one in a converted aquifer, both with minor consequences (no reported injuries or property damage). During the same period, there were six leakage incidents in salt caverns and converted coal mines, two of which involved fatalities.
- The majority of the leaks were associated with wellbore or loss of well control and also two incidents were the results of caprock leak. Remediation action taken was mainly associated with wellbore repair and also with pressure reduction in the reservoir or gas recycling from the shallow zones; or even abandonment of the field.
- The main consequences from the reported leakage incidents were gas leak, explosion and fire; resulting in injuries, fatalities and property damage.
- Catastrophic leaks, where a large volume of gas leaks to surface, can mainly be associated with caverns, as once a leak path is developed there will be a rapid move of gas along the leak path. A small leak in a cavern could result in a concentrated gas release to surface, whereas a small leak from a porous reservoir is more likely to result

in a diffused gas leak. Therefore, the impact of a leak from a cavern is more likely to be severe than a diffused leak from a porous reservoir.

The UNGS leakage frequency calculated in this report was based on leakage incidents identified (see Table 3.11) and was found to be 2.02×10^{-5}/well-yr. The UNGS leakage frequency estimated in the Marcogaz study was 5.1×10^{-5}/well-yr and has been obtained, following a survey of seven UNGS operators in the EU. The Marcogaz frequency was also found to be very similar to the estimated oil and gas blowout frequency.

The leak frequency calculated in the Marcogaz study is approximately 2.5 times higher than the leak frequency calculated in this report. A possible explanation is that leakage incidents identified by Marcogaz during the EU operators' survey, could possibly include significant (ie, incidents that resulted in damage, injury, or significant gas release, etc) as well as minor gas leakages (eg, injection tubing leakage).

In comparison, the UNGS leakage incidents identified in this report could probably represent significant UNGS leakage incidents since the beginning of UNGS operations; as reporting of minor leakages, especially prior the 1970s cannot be considered reliable. Similarly, the following leakage frequencies could be used for GCS:

- 2.02×10^{-5} /well-yr, for a significant CO_2 leakage, resulting in significant loss of CO_2, which could, potentially, affect the environment.
- 5.1×10^{-5} /well-yr, for an average CO_2 leakage from a GCS facility.

The frequency of leaking abandoned wells could not been calculated, although a significant number of abandoned wells in the USA are reported to be leaking. Old, not properly abandoned and possibly unregistered wells could be an issue in GCS projects and proposed areas should be surveyed thoroughly.

Identification of a suitable underground gas storage facility is a complex decision, taking into account:

- Legislation and safety aspects.
- Geological, topographical and physical conditions.
- Commercial issues, such as capital and operational costs, proximity to population centres, any existing compression and distribution infrastructure.

The main criteria used for site selection for natural gas storage in depleted reservoirs and aquifers are as follows.

- Sealed formation, with sufficient porosity and permeability and a thick caprock, preferably with overlaying caprocks and alternating aquifers.
- Sites with high seismicity should be avoided and associated risks such as abandoned wells or adjacent facilities should be carefully addressed. Other issues such as proximity to dwellings and potential potable/irrigation water contamination should also be considered.

- Capital costs, influenced mainly by available infrastructure, UNGS capacity, reservoir depth and permeability. Existing infrastructure in depleted reservoirs is expected to reduce the UNGS capital costs. However, a survey of UNGS operators[5] indicated that there is little difference in capital costs between depleted reservoirs with existing facilities and aquifers.

The above criteria are also applicable to GCS site selection and development. However, as CO_2 fixing is an important factor for successful CO_2 storage, the formation should have suitable components in the rock matrix to react with CO_2 in order to assist mineralisation, and therefore permanent CO_2 fixing.

Initially, from an economics point of view, EOR and possibly EGR, will be the most attractive options for GCS.

The main advantages of depleted reservoirs are, proven containment and existing facilities which can be used for CO_2 injection. The major advantages of converted aquifers are that aquifers are widespread around the world, aquifer water can neutralise CO_2 over the years, and many aquifers are not hydro-geologically active (ie, very slow water movement), increasing aquifer containment. However, the aquifer containment is not proven and can be expensive to develop.

Future competition of GCS projects with natural gas storage is more likely to exist in countries with little underground natural gas storage infrastructure. In the UK, the increased dependence on natural gas imports, growth in natural gas demand and need for supply flexibility; is anticipated to increase demand for UNGS facilities. However, salt caverns and high deliverability depleted reservoirs, are becoming the main choice of many storage operators. No evidence could be found that aquifers will be used in the UK, at least in the foreseeable future, for natural gas storage.

North Sea platforms in depleted reservoirs could be an ideal candidate for GCS projects for the following reasons.

- Existing installations may only have to be reconditioned for CO_2 injection. It is important to note however, that delaying CO_2 injection from existing platforms in depleted fields could bring structure and equipment into disrepair and could significantly increase capital costs.
- Containment of the depleted reservoirs has been proven and operators have a good knowledge of the site.
- EOR or EGR will increase oil or gas production.
- Future competition for geological space, for carbon or gas storage use, is more likely to be for onshore or near-shore reservoirs than far-field North Sea offshore reservoirs. Onshore reservoirs are more likely to be used for natural gas storage than for CO_2 storage.
- Far-field North Sea offshore reservoirs are unlikely to be near a water aquifer used for drinking water or irrigation in the UK. Hence, drinking water pollution may not be a major concern in these areas.

- The public will not be affected or endangered by any potential CO_2 leakage, and so minimum public opposition is anticipated for offshore GCS projects.
- Small CO_2 leakages (eg, 1%) into the bottom of the sea, are not anticipated to have adverse effects; and carbonate compounds formed by CO_2 dissolving into water, may directly benefit organisms (see Section 3.6.4). This CO_2 retention by the seawater, could also be taken into account when adjusting for carbon tax credits, following a minor CO_2 leakage.
- Monitoring of the stored CO_2, using seismic techniques (if required) will be cheaper for offshore locations, than for onshore sites. ROVs and geophones could be used to detect small seabed leakages (see Section 3.5.4).
- The main concern with GCS is caprock leaks, as large quantities of CO_2 could migrate to surface. Caprock leakage in depleted reservoirs is a very rare event, with only one UNGS caprock leakage incident identified in 90 years. Therefore, depleted reservoirs can be considered less likely to result in a significant CO_2 leakage.
- Existing UNGS legislation could be adapted more easily for offshore sites than for onshore, especially if CO_2 injection is not considered 'dumping of waste' when used for EOR. In this case, GCS does not fall within the definition of 'dumping' and could be permissible under the London Convention. Even, if it is considered 'dumping of waste', CO_2 injection could be allowed under the 'force majeure' (see Section 3.2.4), assuming the definition of 'stress of weather', when the safety of human life is threatened, includes climate change from greenhouse gases (eg, CO_2).

To ensure successful GCS, monitoring of the injected CO_2 is required, which aims to:

- Ensure safety of storage project and identify potential leaks.
- Verify quantity of CO_2 injected, for accounting purposes.
- Assess whether storage capacity is being used effectively.
- Ensure effectiveness of EOR (where appropriate).

The following monitoring techniques have been developed by the gas storage industry to ensure gas containment and could be used for CO_2 monitoring.

- Observation wells, which monitor mainly pressure, by recording water level changes.
- Well logging. The main purpose of well monitoring is to identify potential gas leaks from the casing or through cement faults.
- Seismic monitoring and reservoir simulation. Logging information, seismic imaging (mainly 3D and 4D), geostatistics and fluid flow simulation can been utilised to identify any gas leakages.
- Vegetation monitoring and CO_2 gas detection and/or tracers.
- Vadose zone and soil monitoring for CO_2.
- Electrical imaging and gravity surveys.
- Land-surface deformation.
- Reservoir simulation.
- Remote sensing of CO_2 using satellites.
- For offshore wells, geophones, divers and ROVs.

From the above monitoring techniques the most likely methods to be used for the short term monitoring of GCS projects (ie, during injection) are observation wells, well logging and reservoir simulation. The high cost associated with seismic surveys is anticipated to minimise their use in GCS projects.

Following CO_2 injection, post-abandonment monitoring methods could be based on:

- Surface monitoring (including satellite based land surface deformation monitoring), or divers, ROVs and geophones for offshore wells.
- Observation wells. Experience from UNGS operations indicates that observation wells are more likely to be used for converted aquifers, than for depleted reservoirs, to monitor for any signs of CO_2 leakage. However, maintaining an observation well over thousand of years can be very challenging and potentially result in well leakage. Therefore, consideration should be given to the need for observation wells, especially for long term monitoring. Also, if observation wells are required, they could be used for a relatively short period of time, eg, 50-100 years or until CO_2 movement in the reservoir has stabilised and containment has been verified and then plugged and abandoned.
- Vadose zone and soil monitoring for CO_2.
- Geophysical surveys (eg, seismic monitoring) to verify integrity of reservoir (mainly caprock) and wells (ie, cement plugs and corrosion of casing). The high cost associated with seismic surveys is anticipated to affect their use in GCS projects.

Monitoring requirements need to be set on a project (local) scale and also a global scale. When setting the monitoring requirements consideration should also be given to the size of local population (if any). If a GCS project were to be located near an urban area, extra precautions would be required compared to a remote offshore location project. For example, remote offshore GCS projects may require minimum post-injection monitoring (eg, mainly ROV and geophone monitoring) compared to onshore projects near urban areas where seismic monitoring may be required to provide an early warning of loss of containment.

On a global scale, monitoring will provide assurance that CO_2 emission reduction goals are being met. Any significant CO_2 leakage will counteract any greenhouse benefits gained during CO_2 storage. A national and international set of CO_2 reporting and monitoring standards will be required to ensure consistency in CO_2 accounting throughout the nations.

The main gas inventory verification techniques utilised by the gas storage industry, are described below.

- Pressure volume techniques, including material balance calculations which can be used to calculate remaining gas.
- Volumetric techniques, which are more useful during the early stages of an aquifer development.
- Seismic imaging, ie, 3D and 4D techniques used, on a large scale, to verify the gas inventory.

- Gas migration monitoring, ie, if no gas escapes from the reservoir, then the volume of the gas in the reservoir is the same as the volume of the injected gas.

Should a leakage from a wellbore occur, standard oil and gas techniques can be used to repair and plug the well. However, a caprock leakage will be more difficult to identify and repair. To date there are no documented cases of successful sealing of leaking caprocks. However, significant advances in seismic technology eg, 3D, 4D, high resolution crosswell and vertical seismic profiling, could assist in directing a wellbore to a specific location. Research[6] has been performed on foams and other materials to control a leak through a geological fault or fracture.

Some additional aspects that could affect GCS projects are as stated below.

- To increase the CO_2-to-formation water contact, CO_2 should be injected deep in the formation and/or multiple injection wells should be used. This will increase dissolution of water into the aquifer brine, hence trapping CO_2 as a residual phase by gas-water relative permeability hysteresis. Mineralisation might be aided by choosing a formation with suitable components in the rock matrix that will react with the dissolved CO_2.
- Casing and cement should be suitable for the required well's life expectancy. Existing cementing technology can not guarantee the thousands of years required for successful CO_2 storage. However, different types of cement are currently being developed for high pressure high temperature (HPHT) which potentially could exceed the design life of portland cement by far.
- Consideration should be given to removal of all downhole equipment and uncemented casing/tubing strings and deeper plugs should be required for well abandonment. Cementing if possible, of the whole wellbore could be desirable, especially when considering the thousand of years required for successful carbon fixing, the high reservoir pressure and the corrosive nature of CO_2, which could result in CO_2 migration.
- Overpressurisation of depleted reservoirs used for GCS should be avoided. Depressurisation through production and repressurisation with CO_2 above discovery pressure, could potential fracture the caprock or create leak paths to overlying formations.
- Another use for CO_2 could be to provide cushion gas in aquifers, for UNGS. Experimental studies on enhanced gas recovery using CO_2, have demonstrated that there is limited mixing of displaced methane with CO_2, in carbonate rock cores. Therefore, CO_2 could potentially be used as cushion gas for underground gas storage.

CO_2 related (safety, health and environmental) risks are different to natural gas risks due to the benign nature of CO_2 and long duration required for successful storage. Some CO_2 leakage can be anticipated over the years and as long as it remains below certain thresholds, it is not anticipated to affect the environment.

Risk criteria, similar to the HSE individual and societal risk criteria, could be set for GCS activities.

4.2 Recommendations

The following recommendations have been made:

- A clear definition of whether or not CO_2 is a waste product, is required.
- Identify municipal and hazardous waste (eg, radioactive waste) injection regulations and analogues. Also assess legal position for radon leakage and GCS applicability.
- Existing technology for CO_2 pipelines and handling facilities is proven in terms of medium term integrity. Further research is required on the long-term effects of CO_2 on equipment, especially on cement and casing.
- For subsurface monitoring, further research is required on techniques for monitoring the integrity (cement plugs, corrosion of the casing) of abandoned wells.
- More research is needed into the feasibility of seismic monitoring, especially in GCS reservoirs containing residual gas. Existing seismic monitoring techniques may not be able to discriminate between residual natural gas and CO_2.
- Additional research is required on detecting and controlling (eg, using foam) geological faults or caprock flaws, especially for converted aquifers.

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5.2 People and organisations contacted

A selection of people and organisations contacted is as follows:

- A Wildenborg, Netherlands Institute of Applied Geoscience TNO, Netherlands.
- Alexandre Rojey, IFP, France.
- Amanda Francis, National Britannia Group, UK.
- Andy Chadwick, Jonathan Pearce and Jim Riding, British Geological Society, Kingsley Dunham Centre, Nottingham, UK.
- Anthony Fernando, Business Development Manager, Star Energy Group Plc.
- B. Goffe, V.Barlet-Gouedard, B.Piot & J.P Caritey, Sclumberger.
- Bill Horvath, Energy Information Specialist, National Energy Information Centre, USA.
- Brent Miyazaki, President, Innovateur International, Inc. Pasadena, USA.
- Christian Fouillac, Le Bureau de recherches geologiques et minieres, et service geolique national est l'etablisse, France.
- Christine Fagen, Cox Hanson O'Reilly Matheson, Canada.
- Dave Dewett, Consultant, Advantica.
- David Curry, Ed Garrett, Oil and Gas Section Administrator, Florida Geological Survey, USA.
- Doug Brennan, Pennsylvania Powerport, USA
- Dr Nick Riley, Program Manager, Sustainable Energy & Geophysical Surveys, British Geological Society, Kingsley Dunham Centre, Nottingham, UK.
- Duncan Bate, Prof. Peter Styles, Prof. Graham Williams, Keele University.
- Franz May, Peter Gerling, BGR, Germany.
- H. Alkan, ISTec/GRS Cologne, Germany & G. Pusch, Technical University Clausthal, Germany.
- Hans Plaat, HP Petroleum Engineering Services, Reserves Evaluation Underground Gas Storage, The Netherlands.
- Hartmut von Tryller, Andreas Reitze, Fritz Crotogino, SOCON, Sonar Control Kavernenvermessung GmbH, Germany.
- Joachim Walbrecht, BEB Transport und Speicher Service, Germany.
- John Harvard, Energy Markets Unit, DTI.
- John McGrane, Assistant Secretary, NOGEPA.
- John Rowley, Dave Evans, Nikki Smith, British Geological Society, Kingsley Dunham Centre, Nottingham, UK.
- Kamel Bennaceur, Slumberger IPM, West Sussex, UK.
- Kent Perry, Director, E&P Research Gas Technology Institute, Illinois, USA.
- Laurie McClenhan, MHA Environmental Consulting, Inc. The Geological Society.
- Lydia Dumont, Conference Coordinator, The Geological Society, UK.
- Marilu Habel, Department of Conservation, California, USA.
- Michelle Bentham, Sam Holloway, Karen Shaw and Nichola Smith, British Geological Society, Kingsley Dunham Centre, Nottingham, UK.
- Ms. Lisbeth Koefoed, Assistant to the Secretary General, Secretariat of the International Gas Union P.O. Box 550 c/o DONG, Denmark.
- Paulette Bond, Department of Environmental Protection, Florida, USA.

- Peter Radgen, The Fraunhofer Institute for Systems and Innovation Research ISI, Germany.
- Prof.Dr.-Ing. Reza Ghofrani,
- Rob Aptroot, IGU Coordination Committee secretary, Netherlands.
- Robert Sedlacek, Geozentrum Hannover, Geological Survey of Lower Saxony, Germany.
- Thomas Beutel, KBB Hannover, Germany & Stuart Black, ScottishPower, Glasgow, UK.
- Tim Small, Principal Inspector, Gas and Pipelines, HSE.
- Tom Welch, Head of Sales and Marketing, Centrica Storage Limited, UK.
- Troels Aier & Hans 0bro2, DONG, Denmark.
- Univ. Prof Dr.-Ing. Habil. Karl Heinz Lux, Technical University of Clausthal.
- Veronique Barlet, Schlumberger.

6. APPENDICES

Appendix A. Scope of work

SAFE STORAGE OF CO_2: EXPERIENCE FROM THE NATURAL GAS STORAGE INDUSTRY

IEA/CON/04/109

Background

The storage of CO_2 in geological formations is an attractive mitigation option because it offers the potential to achieve deep reductions in atmospheric greenhouse gas emissions when used in conjunction with other options like energy efficiency and renewable energy. The main geological formations that are being considered for CO_2 storage include: depleted oil and gas fields, deep saline aquifers and deep unminable coal seams. Many advocates of geological storage, point to the fact that the geological formations considered have held hydrocarbons and saline water for many millions of years and hence their integrity has been demonstrated. They then extrapolate this point to suggest, that the integrity of the formations to store CO_2 for geological timescales can be assured for that reason. However, such an assumption alone is unlikely to assure all parties in the debate that CO_2 cannot leak out of these reservoirs. To demonstrate effective retention of injected CO_2 other measures are needed. Such measures include: monitoring of CO_2 injection projects, risk assessment studies and the development of rules and standards for CO_2 storage. All these actions will help to build confidence in CO_2 storage as a global mitigation option and help allay fears that injected CO_2 will leak (to any significant degree) and cause adverse ecosystem or environmental damage. Such activities are now underway worldwide. However it may be several more years before a credible data base is established that will allow the issue of security of storage to be finally answered. In the intervening period, this issue will represent a potential barrier to the introduction of CO_2 storage technology.

To help to address this barrier in the near term it will be useful to consider industrial analogues for CO_2 storage, one such analogue is natural gas storage. The storage of natural gas in geological formations has been underway in many parts of the world, notably North America and Europe since the 1970's. Both these regions are developing projects for CO_2 storage. There is therefore experience from the natural gas storage industries in North America and Europe that can be drawn upon to assist the development of the CO_2 storage industry. Also since natural gas is both a valuable commodity and flammable gas, best efforts are made to minimise leakage from any storage site. If this experience can be drawn upon to the benefit of CO_2 storage then this might help allay fears over the potential for CO_2 leakage in the near term.

The aim of this study is to review the regulatory processes and operational practises within the natural gas storage industry and assess their applicability to CO_2 storage. The objective of the study will be to develop a report that can act as a reference manual for IEA Greenhouse Gas R&D Programme (IEA GHG) members in their discussions with policy makers and environmental pressure groups to demonstrate that geological can be a safe and environmentally friendly mitigation option.

Technical Background

The storage of natural gas is an integral, and vital, part of the natural gas production and supply industry. Natural gas is stored for a number of reasons, which can include:

- Security of supply
- Meeting seasonal supply and demand

- Peak lopping
- Greater system efficiency

Natural gas is stored in a number of reservoirs, such as depleted oil and gas fields, aquifers, and in purpose-made caverns in salt and other rock. Typically, hydrocarbon fields and aquifers are used for seasonal gas storage, whilst salt cavities are more suitable for peak lopping. Depleted oil and gas reservoirs tend to be favoured as stores in regions where they are numerous, such as onshore USA. They can be converted from production fields at minimal cost. Conversion to a storage site can take advantage of existing wells, gas gathering systems and pipeline connections. The geology of the fields is usually well known. Also the fields are demonstrated storage sites. However, because the gas is stored in permeable rocks, extraction rates are controlled by the permeability of the host rock and can be limited. Hence these reservoirs are used to meet seasonal demands.

The industry tends to use aquifers in regions where oil/gas fields are limited for instance in the mid-Western USA where most of the US aquifer sites are located. It is considered that aquifers take much longer to establish than hydrocarbon structures because often little is known about the sites beforehand and their establishment costs are higher.

Mined salt caverns are developed in very thick salt formations, known as salt domes. The salt domes are solution-mined to produce caverns. Because of the solution-mining operation (and the need to store or dispose of the discharged brine in an environmentally acceptable manner) they are the most expensive of the three types of natural gas storage facility to be developed. Indications are that they cost between 2 and 3 times more than the other types of storage facility. This type of natural gas storage facility will not be typical of that used for CO_2 storage which will primarily use oil/gas fields and deep saline aquifers.

Currently, only 11% of natural gas storage capacity in the USA uses aquifers. In Europe and Central Asia, the general pattern of use of geological reservoirs is similar to that in the USA. Of the 134 natural gas storage sites in use in 1996 in Europe and Central Asia, 72 were in depleted oil/gas fields, 36 in aquifers, 19 in salt caverns and 2 used abandoned coal mines. However, this varies from place to place - in France, of the 14 developed natural gas storage sites, 11 are aquifers, because of the lack of on-shore oil fields.

In the USA, the existing capacity of natural gas storage was 104.6 Gm^3 (3,695Bcf) in 1993 at 375 onshore sites. Of this capacity 86% (90 Gm^3) is in depleted oil and gas fields. A further 47 projects, adding extra capacity of 12 Gm^3 (429Bcf) of natural gas, were proposed during the period 1994 to 1999. The majority of these new gas projects are based on salt cavern reservoirs. Based on UNECE data in Europe and Central Asia the total stored capacity was 175 Gm^3. As an indication, the total volume of natural gas stored in the USA, Europe and Central Asia represents a storage capacity for CO_2 of some 0.6Gt [1].

The natural gas storage industry is not new; storage in geological formations commenced both in North America and in Europe in the 1970's. Therefore considerable operational experience has developed since that time. Also because of the flammable nature of the gas being stored (unlike CO_2) regulatory processes and safety procedures have to ensure leakage is effectively minimised. Again this experience can potentially be drawn upon to the benefit of the fledgling CO_2 storage industry. The geological reservoirs used for natural gas storage are typically those closest to the demand centres i.e. large cities/centres of population. This

[1] An indication of the mass of CO_2 that could be stored is given by a simple comparison of molecular weights (assuming that the storage pressures for natural gas and CO_2 would be similar).

proximity to towns/cities again means that safety procedures are at their most stringent to prevent leakage occurring.

Scope of Study

Although there are four main types of reservoirs used for natural gas storage it is considered by IEA GHG that not all these reservoir types are relevant to the geological storage of CO_2. It is therefore considered that the focus of the study should be on depleted oil and gas fields and aquifers and not on salt caverns or purposefully engineered storage caverns or abandoned coal mines.

The study would aim to:

1. Review the global locations where natural gas is routinely stored underground in geological formations. The review would outline the volumes of natural gas that are being stored, the types of reservoirs used for natural gas storage, the distribution of the different geological formations that are being used worldwide to store natural gas, the on shore or offshore distribution of storage sites and the timescales over which the industry has been storing natural gas in those regions. The review should also consider the depths that natural gas is typically stored which may be shallower than would be considered for CO_2 storage (typically greater than 800m). In addition, it should highlight any issues that might arise. For instance how long will gas storage development increase and will there be any competition between natural gas and CO_2 storage for geological reservoir space? If, however, natural gas is not stored in reservoirs below 800m there is unlikely to be any competition. Alternately, if both natural gas and CO_2 storage occur at the same time at different levels in the substrata is there any potential that the storage operations could comprise the integrity of each other which would require changes in current regulatory procedures for natural gas storage.

2. Review the current regulations in countries like Canada, USA and Europe that cover natural gas storage and comment on their relevance to CO_2 storage. The aim of the review would be to highlight the key issues within these regulations that ensure natural gas storage is undertaken safely and consider whether these key issues could be transferable to CO_2 storage. The review should also highlight any regional differences in the natural gas storage regulations and comment how such differences might translate themselves into CO_2 storage regulations in the key regions.

3. Review publicly available information on reported leakages from natural gas storage reservoirs worldwide. The aims of this review would be to:

   - attempt to derive a frequency of leakage from natural gas storage reservoirs that has occurred in the main regions where natural gas storage is currently practised,
   - determine the main causes of leakage that have occurred in natural gas storage reservoirs and consider their relevance to CO_2 storage.
   - comment on the impacts of such leakage in terms of collateral damage and injuries/deaths resulting from these incidents

   It is noted that there are a number of listed references to leakages from natural gas storage installations in the USA, most of which occurred in the 1970's. The most recent and probably most serious occurred at the Yaggy gas storage project at Hutchinson, Kansas, USA in 2002. The limited number of more recent leakage incidents has been interpreted as due to improve operational experience and improved operational safety. In Europe data on reportable incidents in natural gas storage projects has been collated by

MARCOGAZ[2]. Between 1970 and 1998, 8 incidents had been reported to MARCOGAZ. The pattern of incidents is similar to the USA experience and was higher in the 70's and 80's. The contractor should review and compare the operational causes of leakage in the USA and Europe and where possible comment on the changes in operational safety that occurred in the USA and Europe to reduce leakage incidents. The contractor should then comment on the key reservoir integrity issues identified and their relevance to CO_2 storage.

4. Review the industrial practises that are used in the natural gas storage industry and comment on their relevance to CO_2 storage. Particular emphasis should be placed here on those practises that emphasise the security of stored gas. The industrial practises to be considered include:

   - Reservoir screening/selection approaches used,
   - Environmental impact analysis requirements and leakage avoidance assessments required for permitting purposes.
   - Risk assessment, management and operational safety practises employed. Safety practises could include; avoidance of reservoir over pressurisation, monitoring of induced seismicity within the reservoir all of which are aimed at leakage avoidance etc.,
   - Monitoring activities, both surface and sub-surface, with particular emphasis on leakage monitoring activities, taking account of the difficulty of detecting small leakages of CO_2 in the presence of natural background emissions.
   - Well abandonment procedures,
   - Remediation procedures employed in the event of a leak occurring.

   In effect the contractor will be advising on "best practise" from the natural gas storage industry that is relevant to CO_2 storage. The contractor should highlight instances where practises in the natural gas storage industry are different from those currently perceived for CO_2 storage. An example is observation wells. In Europe, observation wells are used to monitor the reservoir pressure, extent of the gas bubble and leakage into overlying reservoirs. However the application of observation wells for CO_2 storage has not been favoured by the oil and gas industry in Europe, particularly for offshore storage. However the regulatory bodies may well decide to extend existing procedures and as a result monitoring wells could be imposed if natural gas storage regulations were extended to CO_2 storage, which could have cost implications. The contractor should comment on the likelihood that such precedents could occur. Observation wells are not used for monitoring storage in all cases in the USA - whilst they are used for natural gas storage projects they are not required for the Underground Injection Programme where reliance is placed on reservoir modelling of the plume of injected fluids. In such instances the contractor should comment on the efficiency of observation wells for leakage monitoring compared to other monitoring techniques, like geophysical surveying, and the likely cost implications on a storage project. An IEA GHG study on monitoring for verification of stored CO_2 will be made available to the contractor.

5. The contractor should highlight any differences found in the treatment of different reservoir types and review the reasons why differences arise. For example in European regulations there is a separate standard for aquifers which is more extensive than for oil and gas reservoirs. It is clear in the language of the standard that there is more concern

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[2] MARCOGAZ is the technical association for the European natural gas industry. Their details and the database for major accidents on underground storage facilities can we found at http://marcogaz.org/. The data base is listed under the heading gas infrastructure.

about the long-term integrity of aquifers as natural gas stores. The standard also requires more detailed analysis of the reservoir prior to the development of an aquifer storage site. In addition, the standard also assumes that most of the data required will not be readily available and that detailed data collection will need to be made before the design of the storage facility can begin. The contractor should comment on the impacts of any differential treatment of different reservoirs and their implications for CO_2 storage.

IEA GHG will supply a number of reference materials that are relevant for the development of this study. These reference materials include:

- IEA Greenhouse Gas R&D Programme Report No. PH4/23, Rules and standards for the transmission and storage of CO_2, August 2003
- CO_2 Capture Project (CCP) Report No. 2.1.6, Early detection and remediation of leakage from CO_2 storage projects
- CO_2 Capture Project Report No. 2.2.9, Natural Gas Storage Experience and CO_2 Storage.

Copies of the IEA GHG and CCP studies referred to in the tender will be supplied to the contractor for their use in this study once the study commences.

Additional reference material on natural gas storage project incidents can be readily found on the world-wide web and from publicly available papers from conferences.

It is expected that much of the work will involve desk-based activities but the contractor might consider it necessary to gain additional perspectives on certain issues, so contact with appropriate people in suitable organisations could also be considered. In that case, examples of the organisations which the contractor would contact should be included in the proposal, and the names of the organisations and people contacted should be included in the final report for reference purposes.

Reporting

A draft report, containing the results of the study, will be produced. An unbound paper copy of the draft report and an electronic copy will be delivered by the date specified in the Instructions to Tenderers. The IEA Greenhouse Gas R&D Programme will send copies of the draft report to its expert review panel for their comments and they will be asked to deliver their comments to the IEA GHG Greenhouse Gas R&D Programme within 1 month. Appropriate comments will be passed on to the contractor as soon as possible. The contractor will modify the report to take these comments into account and will deliver the final report within one month of receiving the comments.

Two copies of the final version of the report will be supplied on paper, one of which will be unbound. The final report will also be supplied electronically, on a PC 3.5" diskette, Iomega 100 Megabyte ZIP disk or PC CD-ROM, in Microsoft Word and PDF formats (including all diagrams, illustrations, tables etc.). All diagrams, pictures and illustrations must also be supplied as *.tif, *.jpg or *.gif files at a resolution no less than 300 dpi, unless they have been created in Corel Draw, PowerPoint or Excel, in which case copies in the original format are acceptable. If pictures are inserted into PowerPoint then original *.tif files should also be supplied separately. Photocopies of photographs and illustrations are not acceptable.

The final report (and any material supplied with it, and including this specification) are the property of the IEA Greenhouse Gas R&D Programme and its contents must not be reported or published in any form, written or electronic, without the permission of the IEA Greenhouse Gas R&D Programme.

In addition to the final report, a paper (up to 10 pages) summarising the key findings of the study should be produced for open publication, either in a journal or for presentation at a conference. The conference or journal will be agreed in consultation with IEA GHG.

Progress Meetings

Allowance should be made for up to three meetings (including a project launch meeting) at the offices of the contractor carrying out the study. These meetings may not be necessary given good progress and agreement of the various issues by fax, e-mail or other means. The contactor should indicate whether they would be able to hold progress meetings by video conference if required.
The contractor should nominate in their proposal their proposed frequency and mode of communication for the progress meetings. IEA GHG will be responsible for the costs of its representative attending the meetings.

Form of proposal

The proposal should include the names and qualifications of the persons to be involved in the work. A schedule of the proposed work should be described together with the fixed total cost (in UK pounds sterling) for the work described, together with a breakdown of each individual's contribution (in hours/weeks or days).

If the contractor has not previously carried out work for the IEA GHG programme, references should be given of two independent parties familiar with the work of those tendering for this contract.

Appendix B. UIC regulations. Logs and tests required for Class I injection wells

The logs and tests required[18] for Class I injection wells, under the UIC regulations are summarised below.

Continuous monitoring	Injection pressure, flowrates and ambient monitoring.
One year interval	- Radioactive trace log (RTS). - Annulus pressure testing. - Annulus pressure test to verify no tubing, casing and packer leaks. Temperature and noise logs may be used if required. - Reservoir testing. - Wells should be shut-in for a certain period of time, to ensure valid readings. - Pressure fall-off test to determine characteristics of injection zone. - Pathway of injected waste. No upward migration channels by casing/cement shoe.
Five years interval	- Temperature log. - Casing inspection log. - Casing inspection log. - Check for fluids movements between separate formations. - Check for corrosion. - Check zone for isolation of waste. - Well construction/loss of cement.
Well plugging	- Run mechanical integrity test logs: RTS, temperature, noise. - For final well plugging: casing inspection log and cement bond log prior to well plugging
Other logging tools for safety	- Open hole logs. - E-logs, SP log, Neutron logs, micro F-logs, fracture logs. - Repeat formation tester. - Open hole fluid sample. - Collar location (cement bond log, temperature, casing and casing inspection log). - Thermal decay tool. - Determine cavity top outside casing. - Sonar calliper log. - Determine cavity size and direction.